Transmission Pricing Methodology Consultation

Cross-submission by Transpower New Zealand Limited

Date: 23 December 2021

Contents

Attachments:

A. Chapman Tripp letter: Assurance of Transpower's cross-submission

B. Revised proposed TPM (in PDF and Word)

1. Introduction

1. This is Transpower's cross-submission in response to submissions on the Electricity Authority's (**Authority's**) consultation paper on the proposed transmission pricing methodology (**TPM**). Transpower welcomes the opportunity to provide a cross-submission. As we have noted previously, we consider cross-submissions are particularly useful for matters such as TPM reform where there are competing and disparate views, and complex subject matter.

2. We have closely considered all submissions provided by stakeholders to the Authority as part of its consultation. This cross-submission focuses on some key subjects and does not respond to everything submitted. If we have not responded to a submission, that does not necessarily mean we agree with it. For the most part, our views on all aspects of the proposed TPM are set out in our 30 June reasons paper[1] and 2 December submission.[2]

3. We have included a revised proposed TPM with this cross-submission containing a limited number of further recommended changes, most significantly in relation to prudent discounts, for the Authority's consideration.[3] The prudent discount changes are discussed in section 8 below and respond to certain submitter proposals.

4. We consider the revised proposed TPM with these minor changes is consistent with the Guidelines (except to the extent a clause 2 departure has been previously identified), the Authority's statutory objective and our regulation under Part 4 of the Commerce Act 1986. If the revised proposed TPM does not include a drafting change suggested by a submitter, that means we do not agree with it.

5. Unless otherwise stated, references to clauses of the proposed TPM in this cross-submission are to the clauses of the revised proposed TPM accompanying this cross-submission.

2. Scope of the submissions

6. A number of submissions on the Authority's consultation paper raised matters outside the scope of the TPM. This includes matters relating to:

   6.1 the efficacy of the Authority's 2020 TPM guidelines (**Guidelines**) decision, including its compliance with the Authority's statutory objective;

   6.2 the sufficiency of the Authority's regulatory statement in terms of the requirements of the Electricity Industry Act 2010;

   6.3 the manner in which distributors pass transmission charges through to their customers, including the reach of the transitional price cap; and

   6.4 Transpower's regulation under Part 4 of the Commerce Act 1986, including WACC and risk sharing.

7. This was particularly notable in those submissions on Type 2 first mover disadvantage (**FMD**) that raised issues about whether Transpower should be subject to revenue risk for anticipatory capacity in connection investments (MEUG and Vector, in particular). As we have pointed out throughout the Authority's transmission pricing review, most recently in our Submission, any

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1 TPM Proposal: Reasons Paper, 30 June 2021 (**Reasons Paper**)

2 Transmission Pricing Methodology Consultation: Submission by Transpower New Zealand Limited, 2 December 2021 (**Submission**).

3 The tracked changes in the revised proposed TPM are against the version of the proposed TPM that accompanied our Submission.

policy decision that Transpower should bear increased risk for transmission investments (including the effect that would have on Transpower's WACC) is for the Commerce Commission and our regulation under the Commerce Act and is not a matter for the Authority or the TPM.

8. There were also submissions in relation to the allocation of overhead opex to benefit-based investments (**BBIs**) and the benefit split between load and generation under the simple method that essentially challenged the Authority's policy decision to charge generators for interconnection investments at all. Again, this policy matter was settled by the Guidelines and is not open to revisit as part of TPM development.

9. A number of submitters raised the point that benefit-based charges (**BBCs**) under the proposed TPM will result in increased uncertainty about future transmission charges. For example, CEC (for Trustpower): *"Unlike a conventional LRMC tariff, the BBC methodology - and even the BBIs on which this is applied - are likely to remain uncertain to the customer at the time of their consumption: ie several years in advance of the BBI commitment. This uncertainty will add substantial risk to customer decision-making and associated profitability"*.

10. We see this as inherent in the benefit-based and asset-specific nature of the proposed TPM's approach to recovering the costs of the interconnected grid, as mandated by the Guidelines. The existing interconnection and HVDC charges, in contrast, are determined in a mechanistic way with limited variables that impact on forecasts of future charges. Going forward, any forecasts of transmission charges Transpower provides will, by necessity, come with more qualifications.[4]

3. As little complexity as possible, as much complexity as needed

11. We agree with Mercury the TPM should "*Avoid unnecessary complexity where the benefits are minimal*" and the Authority should err on the side of simple options "*where more than one option would give effect to the Guidelines and the difference in benefits and costs is relatively small and uncertain.*"

12. This is consistent with the principle in clause 1(b) of the Guidelines, which requires the proposed TPM to strike a balance between precision and practical considerations, including simplicity, robustness, certainty and the costs of administering and complying with the new TPM.

13. We consider this principle should extend to TPM-related matters such as possible Code amendments for loss and constraint excess allocation.

14. We depart from Mercury on which TPM options are complex. Some options incorporated into the proposed TPM (or mandated by the Guidelines) are, by their nature, complex. However, contrary to Mercury's view, we consider our proposal for allocating overheads to BBIs would be straightforward to implement.

4. Connection charges: first mover disadvantage

15. We note and agree with Contact's comments in relation to our proposal for recovering the cost of anticipatory capacity in connection investments, and the potential issues associated with the Authority's alternative approach: "*We see the alternative benefit-based options as being overly*

[4] We disagree with Counties Energy's suggestion to address uncertainty about future BBCs by requiring Transpower to provide five-year BBC commitments. Given the investment-specific basis for BBCs (as to timing, covered cost and allocations) the certainty introduced by a mechanism like this would be artificial and create winners and losers. It would also work against the role of BBCs in encouraging investment scrutiny.

complex and therefore unlikely to elicit the stakeholder interrogation of anticipatory investments that the Authority assumes … Under Transpower's "pool and share" approach a stakeholder would be able to approximate with a reasonable degree of accuracy the additional costs to them of anticipatory investments. It is therefore more likely that stakeholders will be motivated to interrogate anticipatory investments". Contact also "*agree[s] with many of Transpower's other points on this issue*".

16. We also note and agree with Northpower and Top Energy that "*the proposed Benefits Based Cost Allocation for anticipatory connection investments … will lead to load customers paying high costs without any benefit which is not consistent with the Guidelines*". Consistent with our Submission, Northpower and Top Energy support their position with a critique of the Authority's Northland example in Appendix E of its consultation paper:

> Our concern is that in our area, we are the only regional beneficiary. The analysis in Appendix E section E.15 shows that 99.7% of the cost would fall onto load customers in the Northland low voltage region. In other words, Transpower can construct capacity that is not required or requested by us, and this will still be charged to us.
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> This runs counter to the basic principle of the TPM that the beneficiary of the cost pays. In this scenario, we would bear all of the cost and risk, and the benefit of lower connection costs (from efficiently building larger scale connection assets) would go to the future hypothetical connecting party. This in effect socialises the costs of the early investment to residential and small commercial consumers, and privatises the benefits to the later connecting party which is likely to be a large load or generator.

17. Mercury *"does not consider there is an efficient or fair way for Transpower to invest in capacity above what a connection customer needs and apportion that additional capacity's cost to any customer(s)."* We disagree. There are significant economies of scale in transmission investment, and it will sometimes be necessary, prudent and efficient to invest in anticipatory capacity rather than making piece-meal investments as each customer commits to new connections (which, owing to construction lead times, may fall short of 'just in time'). We do not consider the efficiency of anticipatory capacity, and whether such investments should be made in the first place, to be up for debate as part of TPM development. Investment approvals and incentives, including for anticipatory capacity, are matters for our regulation under Part 4 of the Commerce Act. The question from a TPM perspective is what is the best way to recover the costs of anticipatory capacity. Mercury's submission does not engage on that question.

5. Benefit-based charges: simple method

18. There was clear delineation between generators (arguing for more costs to be allocated to load under the simple method) and load (arguing the opposite). This included Contact, Mercury, Meridian, Nova and Trustpower who support a 75 (load): 25 (generation) split under the simple method.

19. Very little new evidence was presented in submissions on this topic. In our view, such evidence as was submitted provides an inadequate basis for moving away from the initial 50:50 (or, more correctly, unweighted) allocation we have proposed, noting this would be subject to review and potential amendment for later simple method periods based on actual allocations produced under the standard methods. In our view, the submissions reflect the interests of the parties, particularly generators, and they have been provided without objective, evidence-based rationale for any particular split.

20. Meridian and Mercury relied on the argument it is more efficient to recover the costs of interconnection investments from load than generation.[5] In our view, this is an example of a critique of the Guidelines rather than the proposed TPM. The Guidelines are premised on it being efficient to charge both load and generation for interconnection investments based on their expected positive net private benefits (**EPNPB**), for the reasons set out in the Authority's Guidelines decision paper.

21. Mercury submitted "*The cost and benefit analysis scenario which assumes a weighting factor of 75% to load and 25% to generation from the outset indicates materially higher net benefits than a scenario in which the weighting remains at 50:50 over the full 28 years being assessed ($2.4b vs $1.25b).*" Trustpower made similar submission points.

22. The Authority addressed this point in its consultation paper: "*Switching to, say, a 75:25 weighting factor if that is found to be a more reasonable allocation at the first five-year review point, would still yield near $2.4b in net benefits (see Appendix D). Thus, even if a 75:25 weighting factor were ultimately found to be empirically the appropriate option, the costs of waiting until the five-year review to implement this threshold would be relatively small. It may well be that the review identifies a different weighting factor*".[6]

23. Contact, Counties Energy and Nova submitted that the simple method is too simple, and does not adequately identify beneficiaries:

    23.1 Contact: "*We also consider the proposed 50:50 allocation of benefits between load and generation under the simple method to be such a poor representation of actual beneficiaries in this instance as to be meaningless … [The simple method] assumes that the net private benefits of load and generation customers are broadly equal to Transpower's modelled electricity flows within and between regions. We consider this to be an oversimplification*".

    23.2 Counties Energy: "*For example, [an investment] to increase transmission capacity into a region because of higher load will benefit load with lower prices while at the same time the lower prices will be a negative benefit to generators. Another example is transmission reliability improvements that will again benefit load over generation because reliability improvements reduce the times when the System Operator has to offer very high nodal prices to ensure N-1 supply (actual transmission outages are rare) … CEL would recommend a different logic be applied for the simple TPM allocations that are for a specific region. For example, where the GXP is for injection then allocate the costs to the generators and when for load then allocate to EDBs and directly connected industrial customers. For those few GXPs that are both injection and load, then allocate based on the percentage of GWh injection and load*."

    23.3 Nova: "*In Nova's view: a) load is the primary beneficiary of the n-1 security standard. b) a high proportion of low value investments are associated with improving power quality and Grid reliability rather than capacity upgrades. Load is the primary beneficiary of such investments and therefore an equal allocation between load and generation cannot be an equitable or efficient allocation.*"

24. We disagree with these submissions:

    24.1 The vast majority of our low-value interconnection investments (to which the simple method is required to apply) are to replace aging assets at the end of life, not to enhance

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5 Some submitters also argued this in relation to the allocation of overheads to BBIs.

6 Authority's consultation paper, paragraph 5.38.

the grid.[7] Even if a low-value investment relieves a constraint and reduces nodal prices, that does not mean load customers are the only, or necessarily principal, beneficiaries.

24.2 To the extent these submissions advocate a case-by-case approach for low-value interconnection investments, that would significantly detract from the main (and in our view highly desirable) design feature of the simple method, being its simplicity. The Guidelines require the proposed TPM to balance precision with simplicity (clause 1(b)(ii)), and specifically for the simple method to be "*simple*" and implemented at a lower cost to participants than the standard methods (clause 22(a)).

25. Several submissions appear to assume the 50:50 split under the simple method is a specifically engineered feature of the simple method. That is incorrect. As we said in our Submission, *"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."*[8]. As noted above, we have proposed a variable adjustment factor, initially set to a value of 1, which would allow different splits to be engineered for later simple method periods if the evidence from standard method allocations supports it.

26. Finally, in our view, it is appropriate to recognise load customers will pay 100% of residual charges under the proposed TPM. This means, regardless of whether load receives more than 50% of EPNPB from interconnection investments, and despite an initial 50:50 split under the simple method, load customers will likely pay substantially more than 50% of the cost of interconnection investments. As we noted in our Reasons Paper, *"Accounting for the residual charge, we estimate that generators (in aggregate) would be allocated ~15% of the non-connection transmission charges for the 2020/21 pricing year (our indicative pricing for the new TPM). This could potentially change to ~12-37% in the 2034/35 pricing year"*.[9]

6. Benefit-based charges: standard methods

27. Most submissions on the standard methods related to policy, as reflected in the Guidelines, rather than the proposed TPM. We respond below to some specific submissions on the standard methods in the proposed TPM.

28. **Stakeholder consultation:** Vector submitted that stakeholders should have an opportunity to comment on Transpower's decision whether to use clause 54 (market benefits based on quantity) or 55 (market benefits based on price and quantity) of the proposed TPM.

29. We agree. Clause 16 of the proposed TPM requires Transpower to consult on the starting BBI customer allocations for high-value, post-2019 BBIs. This will include consultation on our decision to use clause 54 or 55 in calculating market benefits for those BBIs.

30. **Resiliency method:** Vector questioned why the resiliency method allocates solely to load.

31. As explained in our Reasons Paper,[10] given the large difference between the value of lost load in the Code ($20k/MWh) and the operating profit of generation (of the order of $100/MWh), we

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7 "*These include, using the year to June 2020 as an example, renewal and replacement throughout the country of insulator sets (874 units, total cost of $5.1m), tower attachment points (631 units, $2.9m), batteries (119 units, $2.1m) and grillage encasement works (174 units, $8.3m).*" (Reasons Paper, chapter 7, paragraph 269).

8 Submission, paragraph 34.

9 Reasons Paper, chapter 7, paragraph 329.

10 Reasons Paper, chapter 7, section 15.

consider the resiliency method will result in allocations that are broadly in proportion to EPNPB without allocations to generation.

32. **Counterfactual:** Unison recommended a change to the counterfactual definition: "*In the CUWLP case-study, when Transpower determined to proceed with the CUWLP the most relevant counterfactual was that "the investment would proceed in future when higher confidence was reached that Tiwai would exit", not that the investment would never proceed. Clause 45(2)(a) does not clearly permit this as a scenario. Our recommendation is that clause 45(2)(a) include provision that the counterfactual "or include the investment proceeding in future*.""

33. We disagree. The counterfactual needs to be the state of the grid without the investment in order to identify the beneficiaries and market benefits of the BBI. If we included the BBI occurring in the counterfactual, both the factual and counterfactual would have the same grid state (after the investment proceeds in the future), and the beneficiaries would receive no allocation. An analogous example is replacement and refurbishment expenditure – the counterfactual needs to be decommissioning the asset being replaced (rather than continuing to maintain the asset at a higher cost than replacing it) so we can identify the beneficiaries and benefits of the continued operation of the asset.

34. **Expected benefits not reflecting actual benefits at a future point in time:** In relation to our CUWLP case study, Unison submitted *"there is very real risk that the benefits to load customers in a "Tiwai exits" scenario never eventuate and the primary benefits of the investment are relief of import constraints to lower South Island customers."*

35. The possibility of beneficiaries and allocations not reflecting actual benefits (assessed after the fact) is a consequence of the Guidelines' requirement that allocations are determined ex-ante with limited provision for adjustment.

36. The specific issue Unison has highlighted is related to our proposal to remove disbenefits after combining with positive benefits over time and across scenarios.[11] This can result in a situation where there are two groups of beneficiaries (groups 1 and 2) in different scenarios (scenarios A and B), but only group 1 receives a charge because the disbenefits of group 2 in scenario A outweigh its benefits in scenario B. This may be particularly stark if scenario A is the present state of the grid and the transition from scenario A to B has uncertain timing and would not trigger an SSCGU.

37. Alternative approaches may be available under the Guidelines as there is flexibility in terms of how EPNPB is assessed. One alternative raised by Unison is a variation on our proposal where disbenefits are removed before scenarios are combined, not after. This approach has some intuitive appeal where two scenarios that have different beneficiaries cannot occur simultaneously e.g. Tiwai leaving/staying in the CUWLP case study.

38. On the other hand, the word *"expected"* used in the context of cash flow analysis is usually interpreted as referring to a statistical mean, in this case of positive and negative benefits across all possible futures. Furthermore, our proposal is aligned with our typical treatment of benefits assessed through the investment test (clause 23 of the Guidelines). For these two reasons, we consider our proposal better complies with the requirements of the Guidelines.

39. **Demand forecast scenarios:** Unison submitted that "*clause 46 [of the proposed TPM accompanying the Authority's consultation paper should] be permissive of allowing different load development scenarios between the factual and counterfactual where the BBI would have a material influence on load investment decisions.*"

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[11] Reasons Paper, chapter 7, section 13.3.

40. We disagree. As we said in our Reasons Paper "*the counterfactual and factual will always use the same demand forecast. In other words, we will assume the transmission investment does not affect the decision for load to connect to the transmission grid. This is a simplifying assumption which limits the scope of the modelling to the electricity market. If we were to assume the demand forecast is influenced by the transmission investment, we would need to significantly expand the scope and complexity of the model – for example, modelling how the electricity price affects consumption and investment decisions in other markets such as transport and industry i.e. a general equilibrium model*."[12]

41. We do not have experience with general equilibrium modelling, and including a requirement to assess the likely entry/exit of load as a response to transmission investment would significantly impact on the costs of administering and complying with the new TPM (clause 1(b)(iv) of the Guidelines). We consider holding the demand forecast constant between the factual and counterfactual will result in allocations that are broadly proportionate to EPNPB.

42. **Mitigating disputes:** Unison submitted "*it may be useful to include either within the TPM or in a separate document a statement of a test and process for the determination of critical assumptions to ensure that: Transpower does not become bogged down in resolving and defending critical assumptions – there should be a reasonable hurdle to challenge the determinations of assumptions; and decisions on assumptions are seen as legitimate, by ensuring the impartiality of decision-makers on critical assumptions.*"

43. Clause 45(5) of the proposed TPM requires the assumptions and other inputs we use for a standard method allocation to be as consistent as reasonably practicable with those used for the investment test, except if we consider they would not result in allocations that are broadly proportionate to EPNPB (as required by clause 23 of the Guidelines). The investment test, and the proposed TPM, requires forecasts of benefits 20 years into the future. It is inevitable there will be contention regarding assumptions and inputs. We do not consider it within the scope of the TPM (or appropriate) to prevent stakeholders providing their views on the assumptions and other inputs we use.

44. The assumptions book is also relevant in this context (clause 39 of the proposed TPM). The assumptions book, on which we must consult, will, over time, provide further transparency and consistency in terms of the assumptions and detailed methodologies we use for standard method allocations. We are currently working on content for the initial assumptions book.

45. **Impartiality:** We do not understand Unison's submission that the CUWLP investment, or perhaps the allocations in our CUWLP case study, demonstrates a lack of impartiality by, or a conflict of interest within, Transpower. We strongly reject that contention, for CUWLP or any other transmission investment. Transpower is interested in revenue adequacy and incentivised to invest efficiently, neither of which are impacted by BBC allocations.

7. Benefit-based charges: covered cost

46. As with submissions on the simple method, there was clear delineation between generators (arguing for more costs to be recovered through residual charges) and load (arguing the opposite). The exception was Trustpower who submitted: "*If overhead opex is reasonably attributable to a BBI investment then it should be part of the costs of that investment*".

47. Few of the submissions engaged with the requirement in clause 15(c) of the Guidelines for the covered cost of a BBI to include "*an amount of opex reasonably attributable to the benefit-based investment*". In our view, as with submissions on the simple method and with the exception of

[12] Reasons Paper, chapter 7, paragraph 107.

Trustpower, the submissions reflect the vested interests of the parties, particularly generators, who made them, rather than providing objective rationale for a different approach.

48. Contact submitted "*the proposal to introduce an attributed opex component to benefit-based charges is inefficient because it will increase costs to generation*". Meridian submitted "*it is more efficient and direct to assign costs to load customers. This is because the demand-side of the electricity market is more inelastic than the supply-side*".

49. The Guidelines are premised on it being efficient to charge both load and generation for interconnection investments based on their EPNPB. It is not the role of the proposed TPM to second guess, or water down, the Authority's policy decision by taking a strained interpretation of the words "*reasonably attributable*" in the Guidelines with the aim of reducing the costs recovered through BBCs.

50. Our Part 1 refer-back response, Reasons Paper and Submission detail why we consider allocating a share of overheads to BBIs would be reasonable, and why we are not satisfied departing from the requirements of the Guidelines by not allocating any overheads to BBIs would better meet the Authority's statutory objective.[13] Having carefully considered the submissions on this topic, we remain of this view.

51. We disagree with Contact's submission that allocating a share of overheads to BBIs is contrary to the Authority's statutory objective or its policy intent (as reflected in the Guidelines).[14]

52. As noted above, and contrary to Mercury's submission, our proposal for allocating a share of overheads to BBIs does not give rise to material complexity or cost issues. It is a straightforward mathematical exercise using inputs we already have.

53. Contact submitted our proposal is a "*material … late stage*" policy change. This is not correct. Transpower has maintained its view that a share of overheads should be allocated to BBIs throughout the TPM development process. This approach has been visible through the publication of our Checkpoint submissions and responses to the Authority's refer-backs on our website.

8. Prudent discount policy

54. Rio Tinto submitted in detail on the prudent discount policy in the proposed TPM. We respond below to the points raised by Rio Tinto and other submitters on this topic.

55. We agree with some of Rio Tinto's submissions, and have recommended corresponding changes to the prudent discount provisions in the revised proposed TPM accompanying this cross-submission. Rio Tinto did not submit in response to our prudent discount consultation during our development of the proposed TPM, so this is the first opportunity we have had to consider Rio Tinto's views.

56. Specifically, we agree:

    56.1 the discount rate for the commercial viability present value calculation should be a post-tax WACC, not pre-tax, because tax impacts are captured in the cash-flows. We recommend the definition of "*ID WACC*" and "*prudent discount rate*" be changed

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13 TPM Proposal 30 June 2021: Decision Part 1 refer back: Transpower's response, 25 August 2021, section 2; Reasons Paper, chapter 6, section 5; Submission, section 6.

14 Contrary to the Contact's submission, we have not proposed to use clause 2 of the Guidelines to depart from the Guidelines' requirements for calculating covered cost. In our view, the attributed opex component of covered cost will result in a reasonable allocation of overheads to BBIs, as required by clause 15(c) of the Guidelines.

accordingly. We also recommend clause 121(3) be amended to be specific to depreciation tax loss or gain, which is consistent with our proposal for calculating covered cost;[15]

56.2 clause 122(2) may have implied the alternative project is required to be fully amortised over the prudent discount calculation period. We have added clause 122(3)(a) to clarify that is not the intended operation;[16] and

56.3 if the alternative project for a stand-alone cost prudent discount (**SACPD**) comprises an optimised grid, the value of the optimised grid should be depreciated according to the age of the part of the existing grid that is optimised. This is now confirmed in clause 137(3).[17]

57. We note and agree with Rio Tinto's support for the customer having a right to terminate its SACPD agreement. For the reasons set out in section 10.3 of our Submission, we do not agree with Mercury's contrary view or Mercury's contention that a right to terminate would result in *"frivolous"* SACPD applications.

58. We also note and agree with Southern Generation's support for the prudent discount practice manual being optional: *"The proposed TPM is also fairly prescriptive about what must be included in the TPM in relation to prudent discounts. This information as well as engagement with Transpower should provide sufficient information to make quality applications for a prudent discount. A PD practice manual might be useful at a later date."*

59. **Multi-customer SACPD applications:** Rio Tinto submitted that multi-customer SACPD applications should be permitted.[18] This would allow several customers to 'join forces' to design a hypothetical alternative project that supplies that group of customers and then have the application assessed on a multi-customer basis (rather than separately for each of the customers).

60. We do not consider this is appropriate, or intended by the Guidelines. Allowing SACPD applications to be assessed on a multi-customer basis would be contrary to clause 47(b) of the Guidelines, which requires the alternative project to be a *"hypothetical investment that would be required to supply <u>solely that designated transmission customer</u> [i.e. the applicant customer]"* (emphasis added). We do not consider departing from this requirement would be consistent with the intent of the Guidelines.

61. Allowing multi-customer SACPD applications could result in an outcome where one or more customers in a consortium who are supplied with interconnection services below efficient stand-alone cost (when assessed on an individual basis) nonetheless receive a SACPD because of their association with other customers in the consortium. The discounts would then be funded by other customers, potentially resulting in a cascade effect where the increase in charges to other customers raises the likelihood they would qualify for a SACPD individually or collectively.

62. In an extreme scenario, all customers would join forces to design a hypothetical alternative project that supplies all of them. If that project (which may have no prospect of actually being constructed) satisfies the SACPD tests, the result would be Transpower failing to recover its recoverable revenue, as there would be no customers outside the consortium to 'pick up the

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15 This is also consistent with how the existing prudent discounts under the current TPM were assessed (Aniwhenua/Matahina and Waipori).

16 Again, this is consistent with the assessment of the existing prudent discounts under the current TPM.

17 The standard approach used for optimised valuation methodologies is to first optimise the assets based on modern equivalent assets (e.g. resulting in optimised replacement cost) and then depreciate the value to reflect the age of the grid (e.g. resulting in optimised depreciated replacement cost. This is a standard and orthodox approach to optimisation, consistent with the previous ODV Handbook rules and the Commerce Commission's application of TSLRIC under the Telecommunications Act.

18 We interpret Rio Tinto's submission to be supporting the assessment of SACPD applications on a multi-customer basis, rather than merely having more than one applicant named on a single application. We have no concerns about customers collaborating for the purpose of preparing an application,

slack'[19]. In that case, a hypothetical notion of efficiency would have completely overtaken real-world efficiency.

63. We recommend new clause 137(4) of the proposed TPM to clarify that SACPD applications must be assessed on a single customer basis.

64. **Brownfields optimisation:** Rio Tinto submitted that clause 138(1) of the proposed TPM *"is an extremely narrow application of a standalone test"*.

65. We disagree. Our reasons for preferring a brownfields optimisation are set out in chapter 13, section 5.3 of our Reasons Paper, and include that brownfields optimisation is consistent with the approach the Commerce Commission adopted for total service long run incremental cost (TSLRIC) pricing for Chorus' unbundled copper local loop (UCLL) and unbundled bitstream access (UBA) services under the Telecommunications Act. Rio Tinto's submission has not changed our view, including our view that holding connection assets constant in the optimisation exercise (clause 138(1)(b)) is appropriate.

66. We note the intent of SACPDs is to reflect the stand-alone cost of transmission services the relevant customer "*receives from the interconnected grid*" (clause (vi)(a) of the Guidelines). This, in our view, effectively removes connection assets and connection charges from the optimisation exercise. We therefore disagree with Rio Tinto's and Refining NZ's submissions that the requirements of the Guidelines for SACPDs will not be met unless connection charges are discounted along with BBCs and residual charges.[20]

67. We disagree with Rio Tinto's submission that the definition of "*transmission services*" in the proposed TPM is limited to transmission services provided by Transpower, which would in turn limit the scope of alternative projects for SACPD applications. The Code does not enshrine Transpower as the only possible grid owner (per definition of "*grid owner*" in Part 1).

68. **Existing corridors and easements:** Rio Tinto submitted that *"the efficient stand-alone cost should be calculated assuming the hypothetical entrant would be able to access transmission corridors at the same cost as Transpower"* and *"no cost should be attributed to these corridors if utilised by the alternative project"*.

69. We disagree. Although the alternative project for an SACPD application does not need to be capable of being constructed, we consider it would stretch the concept of efficient stand-alone cost too far if no cost were attributed to existing transmission corridors. Although much of the existing grid was constructed at a time when transmission corridors were relatively inexpensive, this is part of the real-world efficiency of the existing grid which should not be ignored in the assessment of a SACPD application.

70. The approach Rio Tinto is advocating would require using a selective mix of historic cost (where historic cost is lower than replacement cost) and replacement cost to calculate the alternative project costs.

71. Accordingly, we recommend the addition of clause 121(2)(b) of the proposed TPM to confirm that Transpower's historic statutory rights are not imported to the efficient transmission services provider constructing the hypothetical alternative project.

72. We note this same issue arose in relation to the Commerce Commission's determination of the TSLRIC price for UBA and UCLL copper access services under the Telecommunications Act. The approach the Commerce Commission adopted was to maintain a requirement that forward-looking replacement cost be used, rather than backward or historic actual costs.

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19 Or there might be only a handful of customers outside the consortium, which would create different problems.

20 We also note Refining NZ's observation that the SACPD provisions fail to consider transmission alternatives is not correct. The definition of "alternative project" includes transmission alternatives for SACPDs.

73. **Alternative project costs:** Rio Tinto submitted: *"Alternative projects that include transmission alternatives could have other significant benefits and costs, such as avoided energy costs and market impacts [which are] relevant for determining inefficient bypass and standalone costs."*

74. The Guidelines expressly restrict the analysis for SACPDs to "*the standalone cost of transmission lines services*" (clauses (vi)(a) and 47). For SACPDs, the Guidelines do not contemplate any assessment of the impact of the alternative project on wider costs or prices.

75. The Guidelines are more liberally worded for inefficient bypass prudent discounts (**IBPDs**) but we do not consider the commercial viability test should differ in scope between the two different types of prudent discount. Also, the analysis supporting the two existing IBPDs under the current TPM did not factor in any impact of the relevant alternative project on wider costs or prices.[21]

76. We disagree with Rio Tinto's submission that the present value calculation for the alternative project costs should include a residual value for the non-amortised costs over the rest of the economic life of the alternative project. If that were the case, we would have to do the same for the present value of the avoided transmission charges to ensure the commercial viability test in clause 122(1) of the proposed TPM compares 'apples with apples'. In our view, estimating avoided transmission charges out to 50+ years would not be possible with a reasonable level of confidence.

77. **Substantially similar level of service:** Rio Tinto submitted *"In assessing whether an alternative service is substantially similar, an assessment is also needed of the services actually demanded by the customer."*

78. In response to our TPM development consultation, we received several submissions about the importance of ensuring the alternative project provides a genuinely equivalent service. We only received one contrary submission from NZ Steel that *"The PDP provisions should provide for those who are willing and able to accept a [lesser] supply for a [lesser] cost."*

79. We disagree with the alternative perspective put forward by Rio Tinto, and in NZ Steel's earlier submission to Transpower, which would introduce subjectivity and create incentives for an applicant to overstate their willingness to accept a lower quality service. It should be noted that while the applicant could claim it does not need or want the service quality it is currently getting, the prudent discount would not result in any change in the actual service quality the applicant receives.

80. We remain of the view, as detailed in our Reasons Paper, that the "*cost of supplying transmission services that are of equivalent value to the customer*" (clause 47(b) of the Guidelines) should be determined objectively, by reference to the actual service the applicant receives, not subjectively from the applicant's perspective.

81. We disagree with Rio Tinto's submission that clause 120(2)(d) of the proposed TPM (Transpower's discretion to consider all relevant measures of quality for transmission services) should be removed. This clause is consistent with clause 47(b) of the Guidelines, which requires Transpower to consider *"access to energy, quality of energy supplied, reliability, security of supply, the cost of resource or other regulatory consents, <u>and such other matters as Transpower considers relevant</u>"* (emphasis added).

82. **Renewal of prudent discount agreements:** Network Waitaki submitted *"a prudent discount be allowed to automatically renew unless conditions have materially changed to trigger pre-specified reopeners."*

83. We disagree. The best way to determine if *"conditions have materially changed"* is through repeating the prudent discount application process and applying the applicable tests again. That

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21 Aniwhenua/Matahina and Waipori.

said, much of the ground work for the renewal application will have been done for the original application. The proposed TPM requires that the term of prudent discount agreements to match the relevant prudent discount calculation period, subject to the ongoing satisfaction of any conditions precedent to Transpower's approval of the discount and with an ability for early termination, if required. We think this reflects an appropriate term, and allows for roll-over of discounts to be re-evaluated at the appropriate time.

TRANSPOWER

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chapman tripp

Memorandum

Date: 22 December 2021

To: Transpower

by email

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Confidential and Privileged

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

Introduction

1 Transpower intends to make a cross-submission to the Electricity Authority (**Authority**) in response to submissions provided as part of the Authority's consultation on the proposed transmission pricing methodology (**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 cross-submission:

3.1 comments in response to select issues raised by stakeholder submissions; and

3.2 revised TPM drafting, which builds on the drafting that accompanied Transpower's submission to the Authority of 2 December 2021.

4 In making its cross-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 cross-submission, including its revised 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 cross-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 cross-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

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**

Commented [A1]: Typo

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**

Commented [A2]: Consequential on change to generalise former clause 5(7). See comment on that clause below.

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)

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**

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 a **simple method period**, the period ending on the last **trading period** of the second 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—
(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**

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 alternative~~investment~~**

Commented [A3]: Typo

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

Commented [A4]: On further consideration, we think the term "transmission investment" is more intuitive than "grid investment" to describe both investments in the grid and transmission alternatives.

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, the asset's physical asset life as defined in the **Transpower IMs**

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

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
(a) 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 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)

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**

ID WACC means, for **Transpower** or a **distributor**, the post-tax 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** information disclosure regulation under Part 4 of the Commerce Act 1986

Commented [A5]: The appropriate WACC for the prudent discount calculations is post-tax, not pre-tax. See also changes to the definition of "prudent discount rate" and clause 45(4).

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**~~**transmission investment** or group of related ~~**grid investment**~~**transmission 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 investment**~~**transmission investment**; or
   (ii) the other person agrees to make a contribution to the capital, maintenance, operating or other cost of a ~~**grid investment**~~**transmission 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)

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**

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
(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 investment**~~**transmission investment**s 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** (post-tax) 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 post~~pre~~-tax weighted average cost of capital, that post~~pre~~-tax weighted average cost of capital; or
(iii) otherwise, a post~~pre~~-tax weighted average cost of capital for the applicant **customer** determined by **Transpower** by applying the methodology for estimating **ID WACC** (post-tax) for **distributors** in the **EDB IMs**; or
(b) for a **stand-alone cost prudent discount**, **Transpower's ID WACC** (post-tax) 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 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**~~**transmission 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

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

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**~~**transmission 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
(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
(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
(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
(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

(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**

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

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 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—

(a) was approved by the Electricity Commission under section III of Part F of the **rules**; or

(b) was individually approved by the **Commission** as a major capex project or listed project under the **Transpower Capex IM**; or

(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 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**

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—
(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**

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**.

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

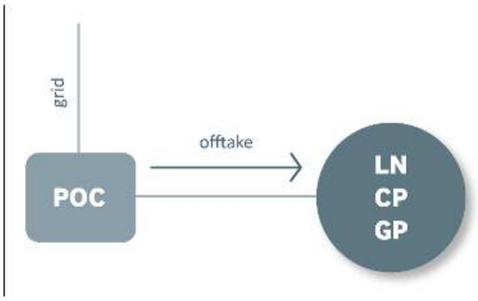


Figure 2

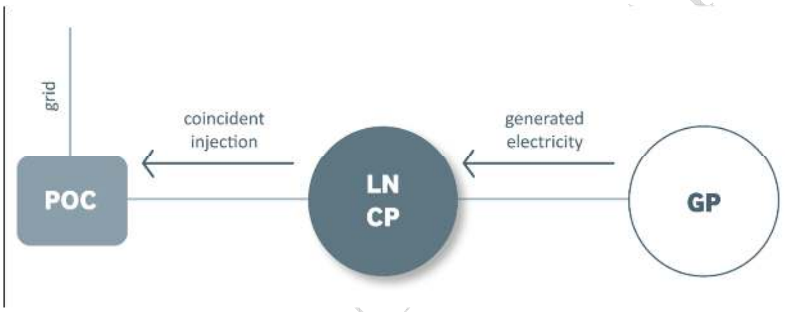
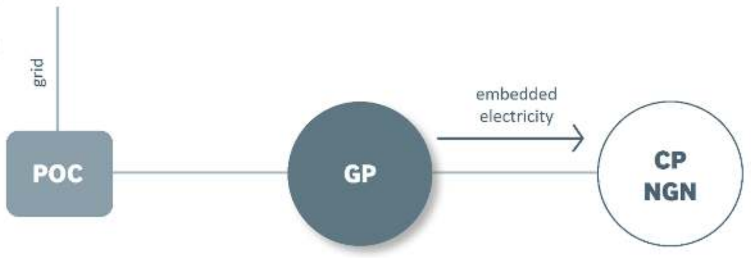


Figure 3

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.

~~(7)~~(1) 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)~~(a) ~~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)~~(a) ~~other **reconciled quantities** published or made available to **Transpower**:~~

~~(d)~~(a) ~~**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)~~(a) ~~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**.~~

Commented [A6]: This subclause is now clause 11(4) and generalised to apply to all allocation data, not just gross demand/energy. This is because the data sources listed will also be the primary data sources for offtake and injection.

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 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.

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

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

(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

(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

(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

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

(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

(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

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**.

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.

(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.

(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) Except as otherwise stated in this **transmission pricing methodology**, **Transpower** may use the following information to calculate **allocation data**~~**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**:

(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.

~~(3)~~(5) **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.

~~(4)~~(6) 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%.

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).

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**.

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

14 Exceptional Operating Circumstances

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

(a) a **Transpower** requirement, **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**.

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

General

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.

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).

(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.

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

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**.

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**.

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

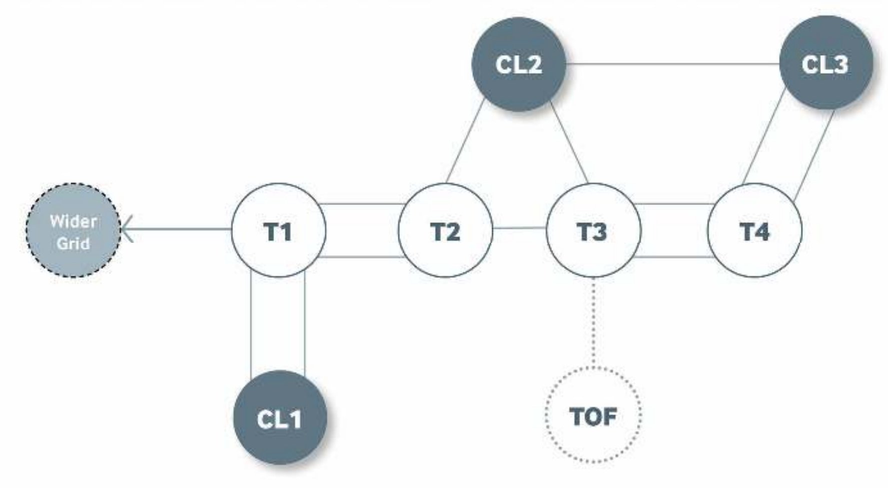
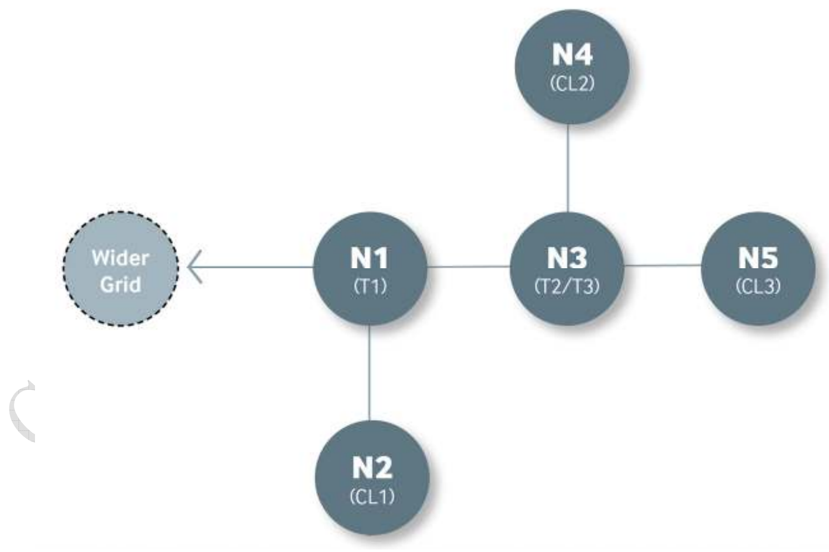


Figure 6



(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**.

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

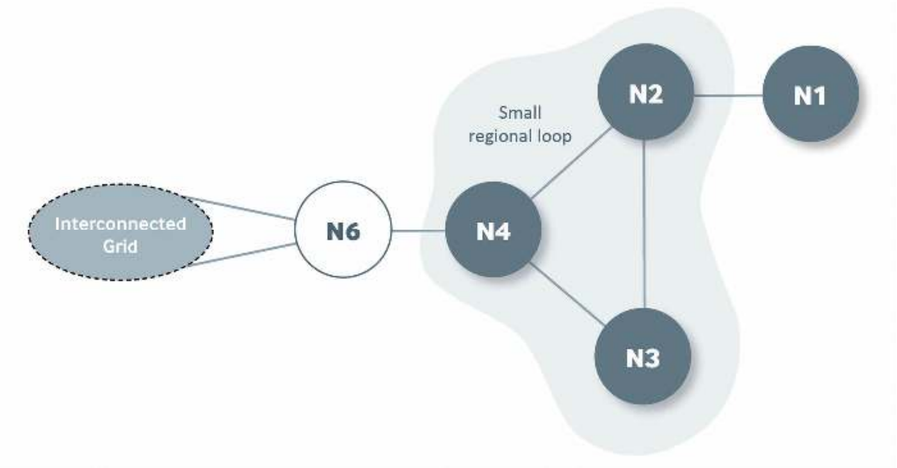


Figure 8

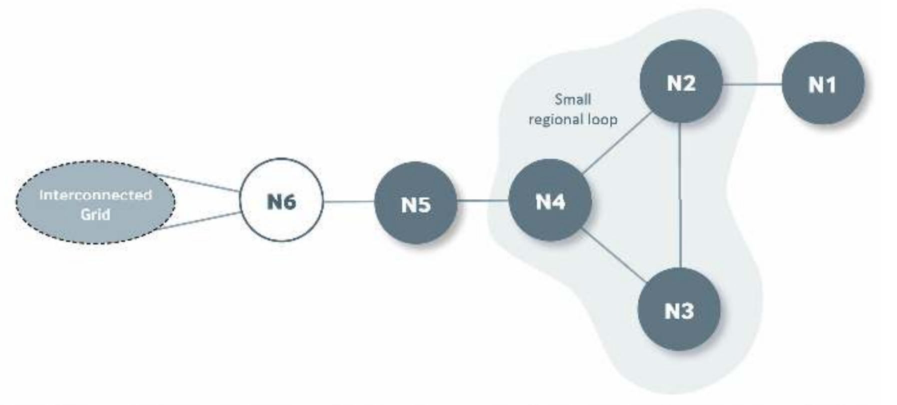
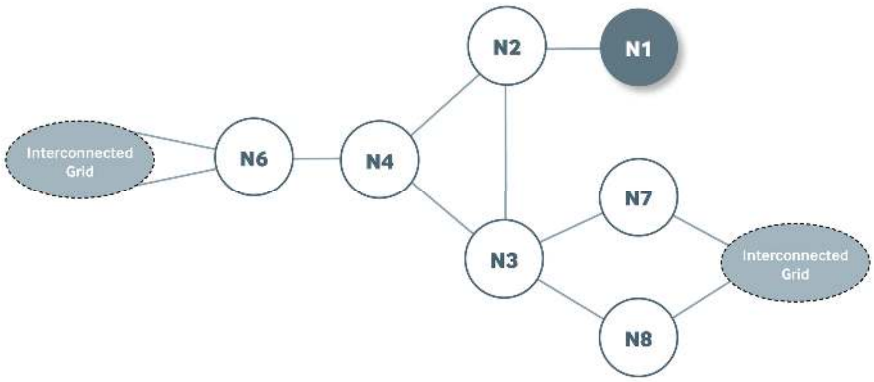


Figure 9



(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.

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**.

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:

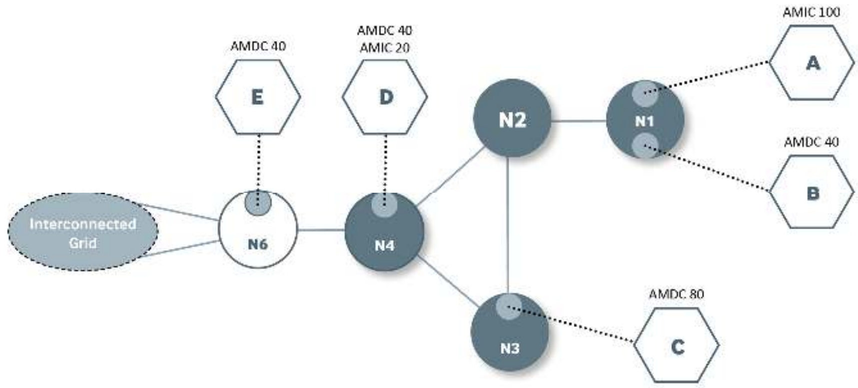
(b) The following table shows which **connection assets** are "for" the **connection locations** at N1, N3, N4 and N6. The **links** with an asterisk are "deep" **connection assets** for the relevant **connection location** because they are not located at, and do not directly connect to, the **connection 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



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

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**

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:

$$A = ARR \times RC$$

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**; or

(b) otherwise, subject to subclause 28(1), the **replacement cost** of the **connection asset** at the end of the preceding **financial year**.

(2) 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** for 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**.

28 Anticipatory Capacity in Connection Assets

(1) Subject to subclause (3), **Transpower** may reduce the value of RC in subclause 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) 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.

(3) **Transpower** must not reduce the value of RC under subclause (1) below any previously reduced value of RC for the **connection asset**.

(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:

$$CC = \Delta RC \times ARR$$

where

ΔRC is the absolute value of the reduction in the value of RC for the **pricing year**

ARR is the **connection asset** return rate for the **pricing year** calculated under subclause 27(2); 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)

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)

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:

$$O = OC \times (1 - ICR_{op})$$

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:

$$OC = ORR \times (S - (0.1 \times S_{cust}))$$

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:

$$ORR = \frac{OC_{switch\ total}}{(S_{total} - (0.1 \times S_{cust\ total}))}$$

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):

link	connection location	customer	connection customer allocation
N1-N2	N1	A	$\frac{100}{140} = 0.7143$
		B	$\frac{40}{140} = 0.2857$
N2-N3 N3-N4 N2-N4	N1	A	$\frac{100}{220} = 0.4545$
		B	$\frac{40}{220} = 0.1818$
	N3	C	$\frac{80}{220} = 0.3636$
N4-N6	N1	A	$\frac{100}{280} = 0.3571$
		B	$\frac{40}{280} = 0.1429$
	N3	C	$\frac{80}{280} = 0.2857$
	N4	D (offtake)	$\frac{40}{280} = 0.1429$
		D (injection)	$\frac{20}{280} = 0.0714$

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**.

(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.

(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**

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

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:

$$T_{inc} = \frac{r \times C}{1 - r}$$

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**

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 investment**~~**transmission investment**s in the **HVDC link**, an allocation of **HVDC opex** for the preceding **financial year** as determined by **Transpower** subject to subclause (2); or

(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

Commented [A7]: Redundant

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**~~**transmission 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

(c) has an **opening RAB value** for the preceding **financial year**,

is treated as if it were a **grid asset**.

43 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

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**.

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:

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** (pre-tax).

(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**.

Standard Method: Price-quantity Method

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**.

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**~~**transmission investment** comprised in the **BBI** is an **enhancement investment**, the **counterfactual** must include the ~~**grid investment**~~**transmission investment** not being made:

(b) if a ~~**grid investment**~~**transmission investment** comprised in the **BBI** is a **replacement investment** or **compliance investment**, the **counterfactual** must include the immediate decommissioning of the relevant **grid asset** or **transmission alternative** without replacement:

(c) if a ~~**grid investment**~~**transmission 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 it without replacement.

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**.

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**.

50 Individual NPB

A **customer's individual NPB** for a **BBI** (NPB) is calculated as follows:

$$NPB = \sum_{g} \left(PVRNPB_g \times \frac{IRA_g}{IRA_{g\ total}} \right)$$

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.

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 is the **BBI's standard method rate**.

(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).

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 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

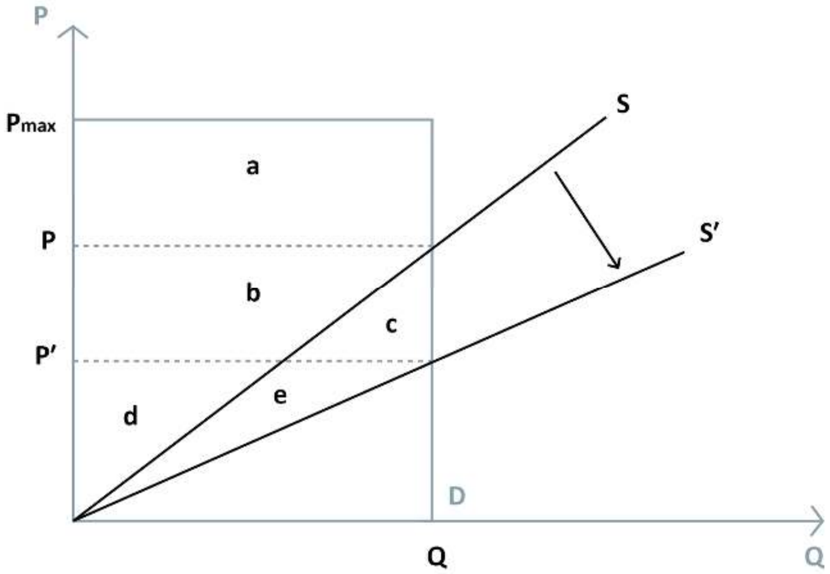
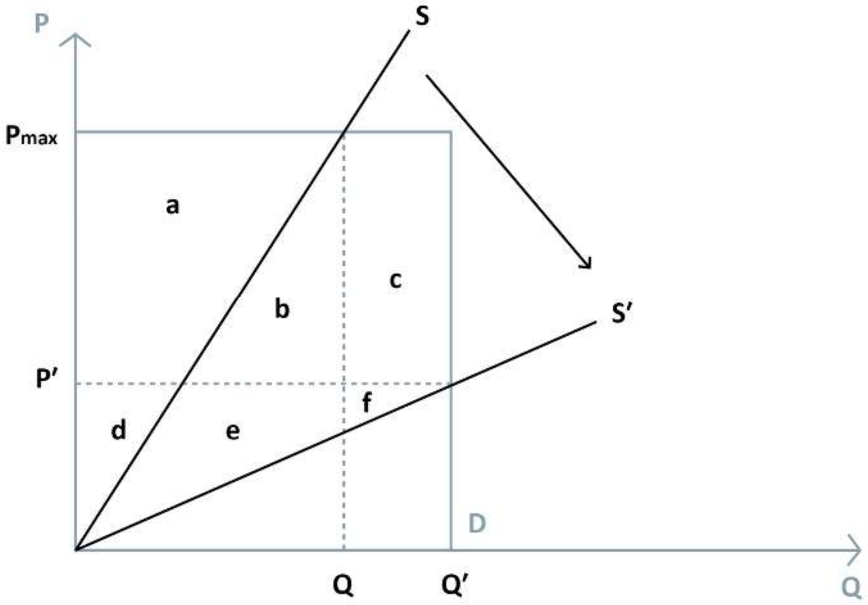


Figure 12



(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**.

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**.

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) the modelling under clause 52; and

(b) the period or periods during which the **market BBI** is modelled to generate 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**:

(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).

(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).

(5) To avoid doubt, subject to clause 49, expected market benefits and disbenefits are not summed between different **regional customer groups**.

(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.

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**.

(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**.

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**

	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**.

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:

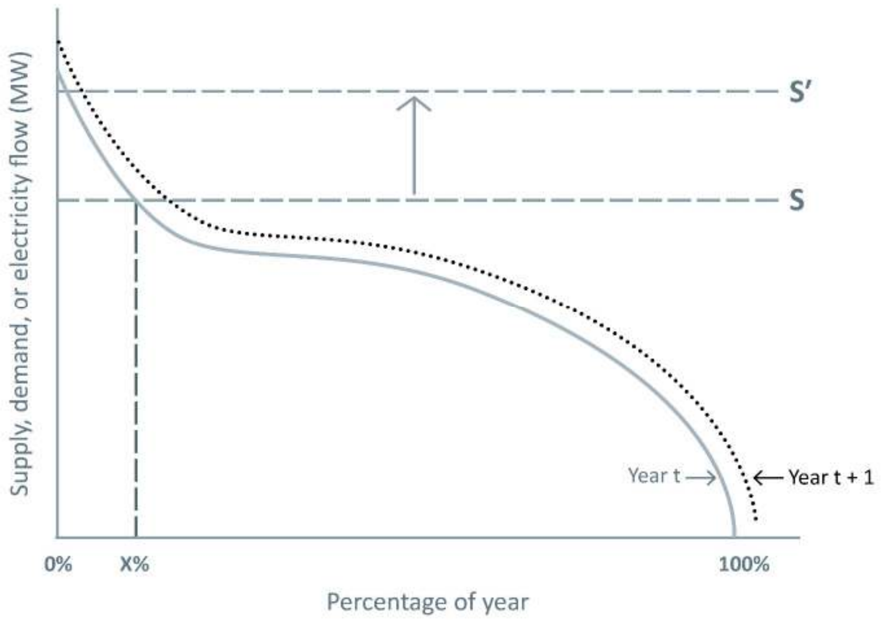
$\Delta ECE = CE \times \Delta P$

where

CE is **Transpower's** estimate of **curtailed energy** caused by the **outage scenario** occurring in the **market scenario**

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).

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

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**.

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**.

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

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)~~45(2)45(2)~~; and
  - (ii) those **high –value intervening BBIs** to which **Transpower** applies the **simple method** in accordance with subclause 45(3); and
  - (iii) **anticipatory capacity BBIs**.

(2) Under the **simple method**—

(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 investment~~transmission investments comprised in the **BBI** are located.

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**.

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).

(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**.

(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** 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**.

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—

(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**.

66 Regional Customer Groups
Subject to subclause 28(5), 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**

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**.

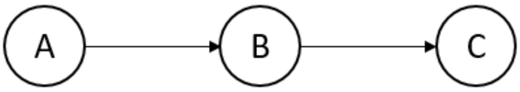
Transpower must publish the **demand adjustment factor** in the **assumptions book** before the start of the **simple method period**.

(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

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:

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)

(3) The **intra-regional allocator** for the **regional customer group** under the **resiliency method** is mean historical annual **offtake** (subclause (5)).

(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)

(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

(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**.

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 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).

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

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**.

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**.

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**,

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; and

(b) may be re-estimated by **Transpower** under clause 76.

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

$LATGE_n$ 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.

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**.

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** are fully operational, but may only re-estimate each of the **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 **recent load customer's AMDR** baseline or average **total gross energy** baseline.

[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.

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

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

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**.

(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).

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**.

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 applying paragraph (a).

82 Connection Charge Adjustment Event: Sale of Business

(1) This clause 82 applies in the case of the **connection charge adjustment event** in paragraph 79(1)(c).

(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**.

(5) **Transpower** must start the purchaser's **monthly connection charges** calculated under paragraph (3)(b), (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.

(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**.

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

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)—

(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.

(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).

(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**.

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 **BBI's write-down** due to the **material damage**, to the extent the **write-down** 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).

(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 applying subclause (3).

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:

$$F = \frac{1}{1 + CA}$$

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

regional customer group	beneficiary	regional NPB	intra-regional allocator	individual 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))

regional customer group	beneficiary	regional NPB	intra-regional allocator	individual 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%

After (paragraph (3)(d))

regional customer group	beneficiary	regional NPB	intra-regional allocator	individual 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

beneficiary	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%

Transition (paragraph (6)(a))

beneficiary	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%

After (paragraph (6)(b))

beneficiary	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**.

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 applying subparagraph (a)(i).

(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

regional customer group	beneficiary	regional NPB	intra-regional allocator	individual 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))

regional customer group	beneficiary	regional NPB	intra-regional allocator	individual 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 than 10 years before the date the exiting **customer** ceased to be a **customer**.

(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 (3)(a)(iii) do not apply; and
(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**.

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.

(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 than 10 years before the date the **large plant** was disconnected.

(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.

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**.

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**.

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.

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 **customer** 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)).

93 Benefit-based Charge Adjustment Event: Sale of Business

(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.

(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

(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.

(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.

(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**.

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**.

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

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**:

(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.

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 applying paragraph (a).

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

(4) This clause 98A applies in the case of the **residual charge adjustment event** in paragraph 96A(1)(c) or 96A(1)(d).

(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**.

(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.

(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**.

99 Residual Charge Adjustment Event: 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

(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.

(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.

(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**.

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

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).

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**.

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**:

$$RT = \$5m \times \frac{CPI}{CPI_{base}}$$

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.

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).

(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**.

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).

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.

(3) Otherwise, **Transpower** must reject the **application**.

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
 (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~~transmission investment comprised in the **eligible BBI** is the expected future peak electrical loading of the ~~grid investment~~transmission investment over the **eligible BBI's forecast loading period**, as determined by **Transpower**.

(3) The **investment reassignment factor** for a ~~grid investment~~transmission investment comprised in the **eligible BBI** is the proportion of the ~~grid investment~~transmission investment**'s** total **replacement cost Transpower** determines it would incur to replace the ~~grid investment~~transmission investment with a ~~grid investment~~transmission 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~~transmission investment i, where ~~grid investment~~transmission investment i is a ~~grid investment~~transmission investment comprised in the **eligible BBI**

IRF_i is ~~grid investment~~transmission investment i's **investment reassignment factor**.

(5) **Transpower** may **publish** in the **reassignment practice manual**, for 1 or more types of ~~grid investment~~transmission investment in, or in relation to, **interconnection assets**, information about the relationship between the ~~grid investment~~transmission 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**.

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.

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**.

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**.

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**.

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 investment**~~**transmission investment**s 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; 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**;

(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 investment**~~**transmission 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**.

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.

(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

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**.

(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.

(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**.

(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.

(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**).

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**; or
(b) the greater of 0 and n-2024 if the **capped customer** is a **direct consumer**

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:

$$\Delta CPI_n = \frac{CPI_{n-2}}{CPI_{19}} - 1$$

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**.

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

Commented [A8]: See section 8 of our submission for discussion of the substantive changes in this Part.

General

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.**

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**.

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).

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.

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**~~.~~,

(a) 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); and
~~(c)~~(b) an efficient **transmission services** provider is assumed not to have any of **Transpower's** historic statutory rights in respect of **works** or activities.

~~(2)~~(3) The **alternative project costs** must be calculated accounting for the **customer's** or efficient **transmission services** provider's depreciation tax loss (positive value) or gain (negative value) for each year of the relevant prudent discount calculation period~~the impact of the relevant capital, operating, maintenance and overhead costs on the **customer's** or efficient **transmission services** provider's tax liability~~.

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**.

(3) To avoid doubt—

(a) the calculation under subclause (2) does not assume the **alternative project** is fully amortised over the **prudent discount calculation period**; and

(b) any residual value of the **alternative project** at the end of the **prudent discount calculation period** is ignored in the calculation under subclause (2).

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).

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**.

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) The~~A~~ **prudent discount** agreement must provide for—

(a) the **prudent discount** agreement to be of no effect unless and until all of the conditions precedent of **Transpower's** approval (if any) are satisfied; and

~~(a)~~(b) the **customer** to pay **Transpower** an annuity, calculated under clause 126, in monthly instalments; and

~~(b)~~(c) **Transpower** to calculate the **customer's transmission charges** in accordance with clause 135 or 140, as applicable; and

~~(c)~~(d) **Transpower** to have the right to terminate the **prudent discount** agreement immediately if any ~~of the~~ condition~~s~~ subsequent of **Transpower's** approval is not, or ceases to be, satisfied; and

~~(d)~~(e) 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—

(a) satisfaction of all conditions precedent of **Transpower's** approval (if any); and

(b) 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**, subject to satisfaction of all conditions precedent of **Transpower's** approval (if any).

~~(3)~~(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**.

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)

Commented [A9]: If Transpower approves an application subject to a condition precedent, that may affect the term of the prudent discount agreement.

r is the relevant **prudent discount rate**.

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**.

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.

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.

(7) The **prudent discount practice manual** may be part of the same document in which the **assumptions book** or **reassignment practice manual** is contained.

Inefficient Bypass Prudent Discount

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.

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**.

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** the **customer** currently receives from~~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).

Commented [A10]: For consistency with the drafting of the definition of "alternative project" and in clauses 120(2) and 137(1).

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 investment**~~**transmission investment**s, 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 investment**~~**transmission investment**s, 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**.

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**.

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

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**.

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.

~~(2)~~(3) In calculating the **alternative project costs**, **Transpower** must value any optimised **grid** comprised in the **alternative project** in a way that accounts for **depreciation** according to the age of the part of the existing **grid** that is optimised.

~~(3)~~(4) To avoid doubt, **Transpower** must carry out the assessment under subclause (1) on a single **customer** basis.

Commented [A11]: Clarification

138 Assessment of Efficient Stand-alone Investment

(1) An **efficient stand-alone investment** is an investment in the **grid** or one or more~~a~~ **transmission alternatives** 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—

Commented [A12]: Clarification

(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~~The **efficient stand-alone investment** does not need to be in the same location or follow the same route as the existing **grid**.

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**.

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

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**

$BBC_{recipient\ k}$ 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)

$RC_{recipient}$ 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

BBC_{cb} is **customer** c's **annual benefit-based charge** for **discounted BBI** b and the **pricing year**

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).

(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**

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).

(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%