TRANSPOWER

TPM Proposal 30 June 2021 Decision Part 1 refer back: Transpower's response

25 August 2021

Contents: Chapter 1

1 Introduction

1. On 28 July 2021, the Electricity Authority (**Authority**) asked Transpower to reconsider some aspects of the proposed TPM that Transpower submitted on 30 June 2021 (**30 June proposed TPM** and **30 June proposal**), excluding matters relating to the benefit-based charge (**BBC**) allocation methodologies.[1] This document provides to the Authority our response following reconsideration of these matters. The Authority responded separately with its feedback on the BBC methodologies on 18 August 2021.

2. The Authority otherwise accepted all other non-BBC allocation methodology related aspects of the proposed TPM for the purposes of its upcoming consultation. We welcome the Authority's comments about the quality of the work undertaken and level of commitment and constructive engagement from both teams. This is reflected in the limited number of matters the Authority has asked Transpower to reconsider.

3. Our role at this step in the process is to reconsider the aspects referred back by the Authority, having particular regard to any new information, analysis or observations supplied by the Authority. The Code requires us to make decisions on each topic having regard to the Authority's statutory objective in section 15 of the Electricity Industry Act 2010, the Guidelines, and any determination made under Part 4 of the Commerce Act 1986, as applicable.

4. In a couple of places the Authority has framed its feedback in terms of non-compliance when the essence is a difference of view about which of the Guidelines-compliant options being considered better promotes the statutory objective. Given the nature of the statutory objective it was probably inevitable there would be different judgments about the application of it to aspects of the proposed TPM.

[1] Authority, letter to Alison Andrew, *Transpower's proposed TPM*, 28 July 2021.

5. In these situations, we are required by the Code to form and explain our view. In providing our explanation we have been mindful that there may be places where the Authority takes a different view about how best to promote its statutory objective, and the Authority may prefer its view for the industry consultation ahead.

6. We have also considered the Authority's feedback on the drafting of the 30 June proposed TPM. This feedback was helpful, and we have taken it into account (as well as the matters discussed below) in preparing the resubmitted proposed TPM provided with this document. The resubmitted proposed TPM includes responses to the Authority's drafting feedback.

2 Overheads (BBC covered cost and connection charge)

7. The 30 June proposed TPM includes a requirement that a share of overhead be allocated to the covered cost of each benefit-based investment (**BBI**), for recovery through the BBC. The Authority has asked us to reconsider this feature. In the Authority's view only directly attributable opex should flow through to the BBC, and all overhead should be recovered from load customers only through residual charges.

8. In its feedback, the Authority expressed its view that (i) Transpower's 30 June proposal is not available under the Guidelines, (ii) the Authority's approach is available under the Guidelines, and (iii) the Authority's approach is preferable under its statutory objective.

9. We have considered this feedback carefully. As we explain below, having worked through the issues raised by the Authority we have concluded:

   9.1 Transpower's 30 June proposal is available under, and consistent with, the Guidelines' requirement for opex that is "reasonably attributable" to a BBI to be included in its covered cost.

   9.2 The Authority has clearly stated its preference for a different approach. This seems to be a development in its previous thinking and statements,[2] but the Authority's current preference is clear. As a matter of form this approach falls to be considered under clause 2, which poses the same question of which approach to allocation of opex better promotes the statutory objective.

   9.3 The ultimate choice falls to be made by reference to the statutory objective. Having worked through the issues presented, we have concluded the 30 June proposal better advances the statutory objective.

2.1 Interpretation of clause 15(c)

10. Clause 15(c) of the Guidelines requires the covered cost of a BBI to include *"an amount of opex <u>reasonably attributable</u> to the [BBI]…"* (emphasis added). The key question raised by the Authority's feedback is how to interpret *"reasonably attributable"* in this context. "Reasonably

[2] For example, from the Authority's 2019 Issues Paper: *"the proposed guidelines will allow Transpower to use broad cost allocation rules to allocate opex to benefit-based investments"* (paragraph B.72); *"… overheads … attributable to a benefit-based investment … would, under this proposal be included in the covered cost of the investment"* (paragraph B.73); *"It is proposed that any remaining overheads and unallocated operating expenses (after the attribution discussed in paragraph B.73 above) would be recovered through the residual charge"* (paragraph B.221).

attributable" is not defined in the Guidelines, but we consider that its meaning can be inferred from:

10.1 the natural meaning of "reasonable";

10.2 the context of the Guidelines as a whole; and

10.3 approaches applied by the Commerce Commission in other regulatory regimes.

The natural meaning of "reasonable"

11. As a starting point, we do not consider there is a single reasonable cost allocation mandated by the Guidelines, with all other options being therefore unreasonable.

12. In our view, when read in the context of economic regulation, for a cost allocation under clause 15(c) of the Guidelines to be reasonable it needs to fall between incremental and stand-alone cost. We consider our proposed approach falls within this range. The Authority's preferred approach would result in an allocation that is below incremental cost and below the level required to avoid cross-subsidies. For this reason, the Authority's preferred approach falls to be considered under clause 2, which we have done.

13. Expanding on this, it is important point to note that directly attributable costs are an accounting concept and do not translate exactly to incremental/avoidable costs, or what the Commerce Commission refers to as "economic common costs". The incremental/avoidable costs of providing a service or, in the TPM context, a particular BBI will include directly attributable costs and also a share of overhead where the size of the overhead depends in part on the provision of that service or asset. This is illustrated well by an example the Commerce Commission used in the appeals against its initial settings under Part 4 of the Commerce Act.[3]

The context of the Guidelines

14. The Guidelines themselves do not otherwise provide any direct guidance. Clause 6 of the Guidelines does require Transpower to provide information about *"the extent to which the residual charge comprises unallocated opex"*, but that is not a requirement to allocate all overhead to residual charges.[4] Similarly, the language in clause 27 confirms that it is the role of residual charges to recover *"any remaining recoverable revenue"* that has not otherwise been recovered from other transmission charges.

15. The use of *"reasonably attributable"* in clause 15(c) of the Guidelines may be compared to the language in additional component F (clause 64). Additional component F provides for an alternative where opex is attributed to the particular BBI it was spent on, and generalised allocation rules or proxies are not used. It can be inferred that the default position under clause 15(c) does not include these restrictions, again implying there is no requirement to use a direct attribution method only, or to allocate all overhead to residual charges.

16. We also consider allocating all overhead to load customers only through residual charges would conflict with the principle in clause 1(e) of the Guidelines - that in developing the proposed TPM *"Transpower must, as far as reasonably practicable, … avoid discriminating*

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[3] Wellington International Airport Ltd v Commerce Commission [2013] NZHC 3289, from [1807]. In that example the incremental cost of the fibre service is directly attributable cost + the avoidable/incremental component of the shared cost (the poles) = $75 + $5 = $80.

[4] We do not agree clause 6 supports the Authority's preferred approach. In paragraph 10.34 of its 2020 Decision Paper the Authority said residual charges *"will recover unallocated overheads and costs"*, suggesting not all overhead will be "unallocated".

between designated transmission customers, except to the extent allowed by these Guidelines or otherwise necessary to achieve the Authority's statutory objective".

17. The Authority has emphasised that clause 15(c) of the Guidelines envisages reasonable attribution of opex to individual BBIs, rather than the pool of BBIs as a whole. We agree. However, this does not exclude attributing overhead to individual BBIs using a generalised allocation rule or proxy, as we have proposed.

Approaches in other regulatory regimes

18. The Authority acknowledges there is regulatory precedent for how we should interpret "*reasonably attributable*" under Part 4 of the Commerce Act 1986 and Part 6 of the Telecommunications Act 2001. Our 30 June proposal is consistent with this precedent.

19. The Commerce Commission input methodologies under this legislation draw a distinction between "directly attributable" and "shared" or "common" costs. "Directly attributable" requires that costs are wholly and solely incurred in providing the regulated service. We consider the absence of this wording from clause 15(c) of the Guidelines is significant to its interpretation.

20. For example, in schedule 1 of the Telecommunications Act, TSLRIC (total service long run incremental cost) is defined as including "*a reasonable allocation of forward-looking common costs*". We are not aware of any suggestion in the Commerce Commission's determination of TSLRIC prices that "a reasonable allocation" could be interpreted as a zero allocation of common costs.

21. The Authority has suggested that "*Cost allocation under the TPM is for a different purpose*" than under the Commerce Act or Telecommunications Act. We do not glean anything from the different purposes to mean costs that are reasonably attributable under that legislation should not be treated as reasonably attributable under the Electricity Industry Act or TPM.

22. While the Authority states "*We … agree with Transpower's statement that clause 15(c) of the guidelines does not use the words "directly attributable" or refer to only avoidable or incremental costs being attributed to BBIs*", the Authority's principal feedback is that Transpower "*should*" only allocate costs that are directly attributable, incremental or avoidable to the covered cost of BBIs. However, this is not an argument that goes to the meaning of clause 15(c). We address this argument below in the context of the Authority's statutory objective.

2.2 The statutory objective

23. Because the Guidelines are not prescriptive as to which of the available cost attribution methodologies should be adopted for overhead, and the alternative proposed by the Authority is potentially available under clause 2, it is necessary to consider the alternative approaches against the Authority's statutory objective.

24. We consider the efficiency limb of the Authority's statutory objective is most relevant in this context. We discuss efficiency below then turn briefly to competition and reliability.

25. We consider the efficiency limb of the Authority's statutory objective is better promoted by our 30 June proposal than the Authority's preferred approach.

26. First, as explained above, the approach proposed by the Authority would result in a cost allocation to BBIs that is less than incremental cost. It would produce results that fail the

efficiency test of being subsidy-free. We believe efficiency is better promoted by an approach that gives results within the range that is expected in orthodox regulatory economics.[5]

27. Second, the essential logic of the Guidelines is that the move to beneficiaries-pay charging, being the fundamental cornerstone of the new regime, better promotes efficiency. We consider TPM design choices that are internally consistent with that approach are to be preferred.

28. The Authority has designed the Guidelines to prioritise cost recovery through BBCs and minimise use of "administrative" charges (the residual charge is an administrative charge), and decided that doing so will promote its statutory objective. This is consistent with the Authority's Decision-Making and Economic Framework,[6] which ranks beneficiaries-pay above administrative options such as the residual charge.

29. Our proposed approach to opex allocation upholds these principles by facilitating primary cost recovery under the benefits-based framework, and helps minimise the extent to which charges affect non-beneficiaries.

30. In relation to the Authority's statement "*Transpower's proposed approach to overheads … places additional costs on generators that are not related to the benefits generators receive from the grid*", we note that under the Guidelines the determination of net private benefits and covered cost are independent tasks. The Authority considered and rejected capping BBCs on the basis of net private benefits.

31. Third, we have reached a different view on whether our 30 June proposal is analogous with a tax on generators, as the Authority's feedback suggests. Our proposed approach ensures generators, and other beneficiaries of BBIs, pay properly cost-reflective BBCs. In a context where generators will pay BBCs and the judgment to be made is as to the size of those BBCs, we think the tax analogy falls away.

32. We note that, in its First Issues Paper, the Authority's view was there are benefits from generators facing higher transmission costs:[7]

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

33. In relation to competition, we simply comment on the Authority's statement in paragraph B.22 of its 2019 Issues Paper that "*Our view is that the recovery of overheads should reflect how they would be recovered in a workably competitive market*". In our view:

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5 And reflected in the Guidelines clauses relating to the stand-alone cost prudent discount.

6 Authority, Decision-making and economic framework for transmission pricing methodology, Decisions and reasons, 7 May 2012.

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

33.1 regulating for the outcome in a workably competitive market is not the same thing as promoting competition in a market; and

33.2 in any event, when the Commerce Commission considered this question under Part 4 of the Commerce Act and Part 6 of the Telecommunications Act, it concluded a workably competitive market would result in common costs (including overhead) being shared and not allocated to one service or group of customers.

34. We do not consider the decision on how to allocate opex to covered cost has a direct bearing on reliability.

2.3 Our conclusion

35. Having carefully considered the Authority's feedback, and its alternative proposal, we reconfirm our 30 June proposal. Our proposal is to allocate a share of overhead opex to the covered cost of BBIs (as well as to our other grid investments including investments in connection assets, non-grid investments and to fully depreciated investments). We also confirm that if this proposal is accepted by the Authority then the rationale for the (existing) injection overhead component in the connection charge ceases and that component should be removed from the proposed TPM.[8]

3 Connection charge - the first mover disadvantage issue (Type 2)

36. The 30 June proposed TPM addresses Type 2 first mover disadvantage for connection investments (**Type 2 FMD**) through the asset component of connection charges (clause 27 of the proposed TPM). The effect is that the cost of anticipatory capacity in connection investments is spread across all customers (load and generation) through their connection charges. The Authority has asked us to reconsider this feature.

37. In its feedback, the Authority expressed its view that "Failing to address the FMD issue could risk connection capacity being under-sized (given the expected increase in demand for connections associated with growth in renewable generation and as the economy electrifies) which would likely not adequately conform with the efficient operation limb of the Authority's statutory objective. A delay in investments in new generation or electrification is also a possible risk (although we consider under-sizing to be the more likely outcome)." We agree with these statements.

38. However, the Authority does "*not agree with Transpower's proposal that a socialisation approach is appropriate*", and its "*concern is to ensure that transmission pricing provides stakeholders with appropriate incentives to seek out and reveal appropriate information to Transpower and the Commission.*" The Authority considers "*these problems risk potential over-investment in anticipatory capacity*" and that our proposed approach is "*inconsistent with the*

[8] As set out in our 30 June proposal, if the Authority accepts our proposal to allocate certain overheads to BBIs, the IOH component of the connection charge will not be necessary and can be removed from the proposed TPM, because all customers will pay BBCs including based on their injection. However, if the Authority does not accept this proposal, our view is that the IOH should be retained, consistent with the current TPM. We note that the Guidelines provisions with respect to the IOH are similar the previous Guidelines and do not preclude the IOH component.

benefit-based approach of the TPM Guidelines." The Authority is also considering, and intends to consult on, whether the solution to Type 2 FMD should apply to greenfields investments in addition to brownfields, and suggests alternative approaches: a targeted benefit-based allocation, and temporary socialisation for up to ten years.

39. We have considered this feedback carefully. As we explain below, having worked through the issues raised by the Authority we have concluded:

39.1 Any solution to type 2 FMD will involve some degree of socialisation. We consider pooling the risk over all customers rather than exposing a single customer or subset of customers to the risk is the most efficient approach.

39.2 Type 2 FMD is a potential problem that is more broad than brownfields connection investments, and making a distinction between greenfields and brownfields proposals risks creating a boundary issue. It is not clear that private connection investments would always be in the long-term interests of consumers, and in any event our proposal will not take away the option for our customers to make their own connection investments.

39.3 The alternative of a targeted benefit-based approach will not result in allocations that are broadly in proportion to the expected positive net private benefits of the anticipatory capacity, and is not available for Transpower to propose, whether by relying on additional component C or otherwise under clause 2.

39.4 The alternative of a temporary socialisation approach changes the cash-flows for the first mover but still leaves Type 2 FMD intact. An option that does not eliminate the risk the first mover ultimately faces the full cost of "C+X" will not resolve the problem.

39.5 We note and support the Authority's intention "*to undertake a full consultation on all options to address the FMD issue*". We suggest that these options should include our proposal and a variation of it using residual charges (rather than connection charges) to recover the cost of anticipatory connection capacity until subsequent movers connect.

3.1 Socialisation of the costs of anticipatory capacity

40. There is a tension between the Authority's acknowledgment of the reason for addressing Type 2 FMD ("*Failing to address the FMD issue could risk connection capacity being <u>under-sized</u>*") and the Authority's reasons for referring the treatment of Type 2 FMD back to Transpower for reconsideration ("*Socialising risks <u>over-investment</u> in connection capacity*"). We have grappled with that tension. In our view:

40.1 some degree of cost socialisation (i.e. beyond the customers connected by the connection investment) is necessary in order to address Type 2 FMD; and

40.2 the differences in approach often go to the extent of socialisation, rather than a binary choice.

41. We have considered the suggestion that the balance can be struck by applying a benefits-based approach to allocating the cost of the anticipatory connection capacity. Our practical challenge with that approach is that, at the time of the investment, we will not know who the future beneficiaries are. The future beneficiaries may not even exist at the time of investment. We will only have a prediction as to the type of future beneficiary, which may not transpire.

42. In places, the choice comes down to socialising the cost across a subset of customers that have been selected on the basis of necessarily poor information, or socialising the cost across

all customers. In our view the latter is more efficient. It avoids concentrating the socialisation on certain customers in an arbitrary and unfair way, when they are unlikely to represent all future beneficiaries, or possibly be future beneficiaries at all. these circumstances, the additional investment scrutiny hoped for when concentrating the socialisation is less likely.[9]

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

3.2 Greenfields and brownfields investments

44. As we have said previously, Type 2 FMD is a potential problem that extends beyond brownfields connection investments. Unfortunately, the fact that greenfields (and brownfields) connection investments are funded under investment agreements, with capital costs recovered outside the TPM, does not make Type 2 FMD a non-issue. That fact remains that it may be prudent and efficient to build more connection capacity than the funding customer wants or needs. Making a distinction between greenfields and brownfields connection investments risks creating a boundary issue for the application of any mechanism to address Type 2 FMD.

45. We have considered whether competition from non-Transpower providers for greenfields connection investments addresses this dynamic. I It is not clear that private connection investments would always be in the long term interests of consumers if they result in connection capacity being built without an eye to future capacity needs, the creation of private property rights in connection capacity or inefficient duplication of connection assets.

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

3.3 Alternative approach: Targeted benefit-based allocation

47. Our general concern about using a benefits-based approach to selectively socialise the costs of anticipatory connection capacity is explained above. In addition, when we consider implementation of this approach we have the following concerns:

    47.1 The allocations under the simple method are derived from historical flows on the interconnected grid. Although it would be workable to apply the simple method allocations to connection investments, the simple method was not designed with connection investments in mind and the logic behind the allocations does not reliably derive net private benefits arising from individual connection investments.

[9] Having more customers exposed to the cost of an investment decision may in fact increase investment scrutiny even if individual exposures are relatively low. Certainly, a customer who has no exposure to the cost of an investment decision is unlikely to be incentivised to discover or share information relevant to the decision.

47.2 The worked example provided by the Authority illustrates the implementation challenges. The principal beneficiaries of a connection investment in the Lower South Island are generators (including future generators) and load across the entire country, but in the worked example charges for the connection investment are allocated to local load only. This results in a concentration of connection charges, and in some cases the concentration could be significant. We have seen some preliminary case study work from the Authority where this appears to be the case.

48. Having worked through the issues with this approach, we have reached the conclusion that the targeted benefit-based allocation alternative would not result in allocations that are broadly in proportion to the expected positive net private benefits of the anticipatory connection capacity over its economic life, which is the cornerstone of the approach to benefit-based charging in the Guidelines. It would not be consistent with the principle in clause 1(a)(ii) of the Guidelines.[10]

49. We have considered the option of adopting additional component C to address Type 2 FMD. We have previously explained why we do not consider additional component C will be helpful in this context:[11]

> The arrangements would need to apply to "*each new connection investment*", not just connection investments where Type 2 FMD is an issue. We do not consider a change of this magnitude is justified to address Type 2 FMD for connection investments when more moderate, targeted options are available (such as the one we have proposed).
>
> More fundamentally, additional component C does not speak to how connection charges are allocated, but rather to "*the annual amount to be recovered for each new connection investment*". In our view, additional component C is about importing the covered cost concept for BBIs to connection charges, not the methods for allocating BBCs.

50. In any event, we are conscious that the focus should stay on identifying the substantive solution. If there is a workable way to address Type 2 FMD that promotes the Authority's statutory objective, it is a question of implementation and form as to whether that comes through additional component C or by way of a departure from the requirements of the Guidelines under clause 2.

3.4 Authority's alternative: Temporary socialisation – up to ten years

51. We have considered the alternative of a temporary socialisation of the cost of additional connection capacity. The essential challenge with this approach is that it changes the cash-flows for the first mover but still leaves Type 2 FMD intact. The Authority has acknowledged this difficulty, observing that this alternative *"does not eliminate the risk that the first mover would pay some additional cost in the event other parties do not connect"*.

52. Our concern is that an option that does not eliminate that risk will not be an effective solution to the Type 2 FMD problem.[12] If the second and subsequent customers do not come on

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[10] *"In developing the TPM in accordance with these Guidelines, Transpower must, as far as reasonably practicable, use the following principles, including in selecting between options which otherwise comply with these Guidelines: … (a) set charges in a way that … (ii) reflects the share of positive net private benefits those designated transmission customers are expected to derive from* [new investment in the grid, access to the grid and use of the grid]."

[11] Transpower, Chapter 5: Part C - Connection Charges, 30 June 2021

[12] A longer period than 10 years would be better, but still not a complete solution.

board within 10 years, the first mover will bear the cost of the anticipatory capacity, albeit in 10 years' time and not immediately. There remains a significant risk that, faced with the risk of ultimately bearing the full cost of "C+X", a customer would agree to pay for "C" (noting again the customer always has the option to build its own assets).

53. While the Authority states a benefit of its proposal is that *"it does not permanently socialise the costs of X"* in our view this is a disbenefit. We consider pooling the risk prudent and efficient investment in X, ex post, turns out not to be needed is a more efficient outcome than the first mover (or first movers) arbitrarily bearing the risk.

54. Considering implementation issues, the temporary socialisation alternative is workable, but would be relatively complicated to administer due to the need to operate one or more "rebate accounts". While, by themselves, the rebate accounts would not be overly onerous to operate, we are reluctant to incur additional complexity on top of the complexity already in the proposed TPM, particularly for a mechanism that in practice is unlikely to address the Type FMD problem. We are mindful here of the principles in clauses 1(b)(ii) and (iv) of the Guidelines.

3.5 Our conclusion

55. We have considered carefully the alternatives raised by the Authority. We have concluded our 30 June proposed approach will be more effective in addressing this risk and promoting the Authority's statutory objective than the alternatives. We also consider our proposed approach is appropriately straightforward and pragmatic given what we know today about the size of the Type 2 FMD problem, i.e. that it is likely to be a niche, targeted problem.

56. We note and support the Authority's intention *"to undertake a full consultation on all options to address the FMD issue"*. We suggest these options should include our proposal and a variation of it using residual charges (rather than connection charges) to recover the cost of additional connection capacity until subsequent movers connect.

4 Application of the residual charge to storage

57. Having considered the Authority's feedback, our proposal for the application of the residual charge to batteries (and other storage) remains largely unchanged from our 30 June proposal. The resubmitted proposed TPM is consistent with clauses 27 to 30 of the Guidelines by treating all grid-connected and embedded batteries as gross load for their entire offtake and embedded electricity.

58. We consider the TPM should achieve competitive neutrality, including between different technologies and between different customers, to the extent it can under the Guidelines. We also place weight on the role utility-scale batteries can play in New Zealand achieving its emissions reduction goals.

59. However, as we have said previously, the battery issue is a policy matter which is most appropriately resolved by the Authority. As we heard from submitters on our batteries' consultation, the battery issue may be a subset of wider issues arising from the use of gross load as the allocator for residual charges, and involves consideration of whether special treatment should be available for energy storage solutions such as batteries which draw energy for storage to inject during peak periods. It is clear from responses to our consultation

there is a wide range of views on whether, and to what extent, there should be a residual charge exemption, or some other special treatment, for batteries.

60. We note the Authority's comment in its feedback that referring back the battery issue is a *"precursor to the Authority fully engaging with stakeholders"*. From that we take it the Authority is still in the process of developing its policy, and needs to hear more from stakeholders on the battery issue as part of its consultation on the proposed TPM. We consider the most appropriate "baseline" for that further consultation is a proposed TPM that does what the Guidelines require in terms of the application of the residual charge to batteries, as reflected in our 30 June proposal.

61. The Authority has asked us to comment on the workability of alternative approaches. As we said in our response to the Authority's request for information (20 July 2021), we consider the partial exemption option would pose the fewest workability challenges. This is because we would not need to know how individual embedded batteries are charging and discharging to calculate total gross energy, as this would be reflected in grid offtake and non-battery generation. That said, and as we have noted previously, there are non-trivial data availability challenges for all types of generation not injected into the grid. We consider this workability issue, which arises from the use of gross load to allocate residual charges, needs to be addressed by a Code change outside the TPM, regardless of how batteries are treated.[13]

62. We also consider that if battery owners do not pay a residual charge for the electricity they "consume" as losses (i.e. electricity that is used up and not re-injected), this may over-shoot the competitive disadvantage problem, putting batteries at a competitive advantage relative to other types of generating plant that would pay a residual charge for any electricity they consume.

63. We have made two changes to the proposed TPM following consideration of the Authority's batteries feedback:

    63.1 We have added a definition of "generating plant" and amended the definition of "consuming plant" to clarify that batteries (now also defined[14]) are generating plant when discharging and consuming plant when charging. This ensures batteries are clearly captured as "plant" under the TPM, including for the purposes of the adjustment provisions in Part F of the proposed TPM.

    63.2 We have expanded the definition of "embedded electricity" in clause 5(1) to capture embedded generating plant (including batteries when discharging) injecting into embedded consuming plant and networks. Injection into embedded consuming plant and networks would not otherwise be captured as part of "gross energy", which it is required to be under clause 28(a) of the Guidelines and paragraph 2 of the definition of "gross".

13 Refer to Transpower, TPM Proposal Reasons Paper, 30 June 2021, Chapter 16, section 4.

14 As we noted in our response to the Authority's request for information, we consider the proposed Code definition of "energy storage system" in the Authority's draft decision paper for enabling participation in instantaneous reserve is too narrow for TPM purposes, and not strictly accurate in terms of how a battery stores energy.

5 Adjustments – setting the residual charge for a new entrant

64. Our 30 June 2021 proposal reflects the requirements of the Guidelines according to the Authority's interpretation in its feedback on our Checkpoint 2B resubmission.[15] We agree this interpretation results in new and existing customers being treated differently when they connect new consuming plant in terms of the timing of their resulting residual charges. We identified this as a competitive neutrality problem in our Checkpoint 2B submission[16] and resubmission.[17]

65. The Authority proposes this problem be addressed by ramping up the residual charge for a new customer to match what would happen if the new consuming plant were connected by an existing customer. Our consideration of this option has been informed by the worked example in Appendix 1, which illustrates hypothetical pricing outcomes for three potential approaches: our 30 June proposal, the ramp-up method for new customers proposed by the Authority, and the step-change approach we proposed in our Checkpoint 2B submission.

66. We do not consider the Authority's proposed ramp-up method for new customers would fix the competitive neutrality problem. The worked example illustrates that the Authority's method does not address the competitive disadvantage an existing customer with existing load would have relative to either a new customer or an existing customer connecting new load.

67. Of the three approaches considered, our view is the approach that best resolves competitive disadvantage is the approach we proposed in our Checkpoint 2B submission – make a step adjustment to an existing customer's residual charge when the customer connects large consuming plant to, or disconnects large consuming plant from, the grid or its local network or grid-connected plant. We have reintroduced these step adjustments in clauses 90 and 93 of the resubmitted proposed TPM.

68. This step-adjustment approach would be a departure from the requirements of clauses 33(a) and 33(e) of the Guidelines (as would the Authority's proposed ramp-up approach). We consider this departure is justified under clause 2 of the Guidelines.

    68.1 We consider the departure is not inconsistent with the intent of the Guidelines. Making residual charge step adjustments when there are large plant changes helps recover residual revenue "*in a way that is designed to minimise any effect on designated transmission customers' decision making*"[18], including by eliminating an incentive for the corporate structuring (avoidance behaviour) mentioned by the Authority in paragraph A.69 of its feedback.

    68.2 We consider the departure promotes the efficiency and competition limbs of the Authority's statutory objective (and, as noted above, does so in a more complete way

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15 Authority, Transpower's TPM Checkpoint 2b re-submission, 24 May 2021, paragraphs D.15 and D.16. We note that, at the time of its Checkpoint 2B resubmission feedback, the Authority considered the method we ultimately proposed to be more than merely an "available approach". The Authority described the method as a "decision reflected in the Guidelines". The Authority also considered the ramp-up method for new customers would be a departure from the Guidelines.

16 Transpower, TPM Development Checkpoint 2 submission: Adjustments, March 2021, paragraphs 27 to 29.

17 Transpower, TPM Development Checkpoint 2 resubmission: Adjustments, May 2021, paragraphs 61 to 64.

18 Being the purpose of the residual charge in clause (v) of the Guidelines.

than the Authority's proposed ramp-up method for new customers). We agree with the Authority that the behaviour our proposal is intended to avoid (for both connection and disconnection[19] decisions) is "*artificial and potentially inefficient*". Our proposal would also address the competitive neutrality problem for all load customers (new, existing with new load, and existing with existing load) and ensure a level playing field for potential competition between modes of connecting large consuming plant, particularly grid connection versus embedded connection.

69. The departure is also consistent with the principle in clause 1(c) of the Guidelines (avoiding incentives to inefficiently avoid transmission charges).

6 Adjustments – definition of reduction event

70. We consider our proposed definition of "reduction event" is consistent with clause 29 of the Guidelines. However, we do agree the definition is narrower than necessary to achieve consistency with clause 29. The Authority's feedback makes it clear the Authority intends the definition to be wider than we proposed.

71. The resubmitted proposed TPM has the following changes to the definition of reduction event:

    71.1 The exclusion for a change in the market for the customer's products or services in paragraph (c)(ii) (now (b)(ii)(B)) of the definition of reduction event now does not apply to a change in the market for the customer's services as a host customer to an unrelated entity. This means, for example, a distributor can claim a reduction event if an unrelated person connected to the distributor's local network reduces its load due to a change in the market for its products or services.

    71.2 The exclusion for financial stress in paragraph (c)(iii) (now (b)(ii)(C)) of the definition of reduction event now specifies the relevant event (e.g. being put into receivership) has to have occurred in respect of the customer or a related entity. This means, for example, a distributor can claim a reduction event if an unrelated person connected to the distributor's local network reduces its load due to financial stress.

72. We note that these exclusions exist because, generally, how a customer responds to market changes or financial stress will involve a significant element of choice. In that case, it may not be practicable for Transpower to determine if, or the extent to which, a change in the customer's expected maximum gross demand is beyond its reasonable control.

73. We have made two further changes to the proposed TPM following consideration of the Authority's feedback on the definition of "reduction event":

    73.1 We have changed the definition of reduction event to use the language "event or series of directly related events" to match the language used in the definition of "substantial sustained change in grid use".

[19] We do not agree with the Authority's comment in paragraph D.14 of its feedback on our Checkpoint 2B resubmission that plant disconnection is *"a boundary issue [between exiting and remaining customers] that creates an arbitrary distinction that cannot be avoided."* We consider our proposal for making a step adjustment to the residual charge when large plant is disconnected addresses this potential issue.

73.2 We have added wording that allows Transpower to take into account events that will occur before the start of the first pricing year but have not occurred by the time Transpower notifies transmission charges for the first pricing year.

7 Prudent Discount Policy - stand-alone cost prudent discount

7.1 Impact on transmission charges

74. We have considered carefully the Authority's feedback on our 30 June proposal for a stand-alone cost prudent discount (**SACPD**) on transmission charges. We continue to believe our 30 June proposal is consistent with the Guidelines. However, we are proposing changes in response to the Authority's feedback to more directly achieve the appropriate outcome for customers in the event of a SACPD.

75. The resubmitted proposed TPM has both the recipient's BBCs and residual charge reducing to zero in the case of a SACPD (clause 135).[20] These transmission charges will be replaced with a contractual annuity reflecting the stand-alone cost of supplying interconnection transmission services, or alternatives for them, to the recipient. The recipient's BBCs and residual charge go to zero so that the recipient does not pay more than its stand-alone cost for interconnection services (see also clause 131, where we have added some additional wording to clarify this). As a result, the recipient does not pay a cap recovery charge or any prudent discount recovery charge either.[21] The recipient's connection charges (which relate to connection services) do not change.

76. We have made two other changes to the proposed TPM following consideration of the Authority's prudent discount feedback:

76.1 We have added subclause 120(4) to address a potential issue for regulated distributors' recovery of prudent discount annuities. Prudent discount annuities, which are contractual debts rather than transmission charges, are currently not expressly captured as recoverable costs in the EDB IMs.22 This change deems the annuity payable by a prudent discount recipient to be a transmission charge payable to Transpower under the TPM, to overcome this issue.

76.2 We have added paragraph 135(b) to clarify that a SACPD agreement will not provide for a discount on transmission charges other than BBCs and the residual charge. No other transmission charge discounts need to be provided for to ensure the recipient pays no more than its stand-alone cost of interconnection services.

7.2 Funding

77. The resubmitted proposed TPM does not have any change to clause 136 (prudent discount recovery charges). The formulae in subclauses (1) and (2) provide for the same "mixed funding

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[20] We have also made a consequential change to the definition of "avoided transmission charges".

[21] Both of these transmission charges depend on a customer having non-zero BBCs and/or a non-zero residual charge, which will not be the case for a SACPD recipient. We have made a minor amendment to clause 112(2) of the proposed TPM to clarify this.

[22] Electricity Distribution Business' Input Methodologies clause 3.1.3

model" we proposed in our Checkpoint 2 submission in cases where the prudent discount impacts both the recipient's BBCs and its residual charge or connection charges.[23] As the Authority notes, it has previously indicated the mixed funding model would likely be acceptable as consistent with the Guidelines. The resubmitted proposed TPM (and the 30 June proposed TPM) gives effect to that model, facilitating recovery from other non-recipient customers on a proportionate basis, in accordance with the recovery formulae.

78. We expect it will be the case that virtually all prudent discounts will impact both the recipient's BBCs and residual charge or (in the case of an inefficient bypass prudent discount (**IBPD**) connection charges, but it is conceivable there could be a prudent discount that only impacts the recipient's BBCs.[24] In that case we do not consider it would be consistent with clauses 15 and 16 of the Guidelines to recover any part of the prudent discount through residual charges (hence $RC_{recipient}$ in subclause (1) would be zero, as would PD – A - BPDS in subclause (2)).

79. To clarify the way the proposed prudent discount recovery charge formulae work:

    79.1 The formula in clause 136(1) of the proposed TPM calculates the amount of the net prudent discount that is taken to relate to a discounted BBI (of which there may be more than one). This is the work of the first ratio in the formula. This amount is then spread across the beneficiaries of the discounted BBI, other than the recipient, in proportion to their BBCs for the discounted BBI. This is the work of the second ratio in the formula.

    79.2 If there is any part of the net prudent discount unallocated after applying the first formula (which, as noted above, will almost always be the case) the formula in clause 136(2) spreads the remainder across load customers, other than the recipient, in proportion to their residual charges.

8 Authority's feedback on our proposed TPM drafting

80. Our responses to the Authority's drafting feedback on the 30 June proposed TPM are in the annotated comments in the resubmitted proposed TPM. The resubmitted proposed TPM contains the changes we have adopted.

81. We also made a small number of other drafting improvements in the resubmitted proposed TPM. The principal ones are as follows:

    81.1 We expanded the definition of "post-2019 BBI" to fully capture all potential scenarios for BBIs making up a single interconnection investment.

    81.2 We changed paragraph (a) of the definition of "start pricing year" so it works with the proposed method for calculating covered cost. Without this extension a BBI commissioned on, say, 1 August of a year would need to have a BBC starting on the next

[23] We provided an example of how this method will spread prudent discount recovery across beneficiaries of the relevant BBIs and load customers (through their residual charges) in paragraph 19 of our Checkpoint 2B resubmission.

[24] The most obvious example of this is a generator who receives an IBPD based on an alternative project for its injection only.

1 April despite the BBI not having a value in the relevant financial year (which would have ended before the BBI was commissioned).25

81.3 We simplified and clarified subclauses 40(2) and 40(6), relating to the calculation of covered cost and what happens if a commissioned asset has not been "closed out" at the relevant time.

[25] Delaying the start of the BBC for a commissioned BBI is a departure from the requirements of clause 66 of the Guidelines, which we consider is justified under clause 2. This is discussed in section 8.2 of Chapter 6 of our TPM Proposal Reasons Paper, and those same reasons support this further minor change.

Appendix A Residual charges worked example

A.1 Introduction

82. In this appendix, we have prepared a simplified worked example for a set of hypothetical load customers illustrating the three main approaches under consideration for adjusting residual charges when new large plant is connected, including when there is a new entrant (**Worked Example**).

83. The Worked Example will analyse the residual charges payable by three different direct consumers under those approaches. Each direct consumer operates an identical factory producing the same products, with the same AMDR (**Factory**).

84. The three direct consumers are:

    84.1 L1 – an existing customer with a Factory that has been connected to the grid for at least 8 years;

    84.2 L2 – an existing customer, which connects a new Factory to the grid;

    84.3 L3 – a new customer, which connects its Factory to the grid.

85. For simplicity, we have assumed that at all times the residual charge payable with a Factory operating at full capacity would be $100.

86. The Worked Example below shows the adjustments to each customer's residual charges in each of the following scenarios:

    86.1 residual charge adjustment approach in the 30 June proposed TPM (**30 June Approach**);

    86.2 residual charge ramp-up approach for new customers, as proposed by the Authority (**Authority Approach**); and

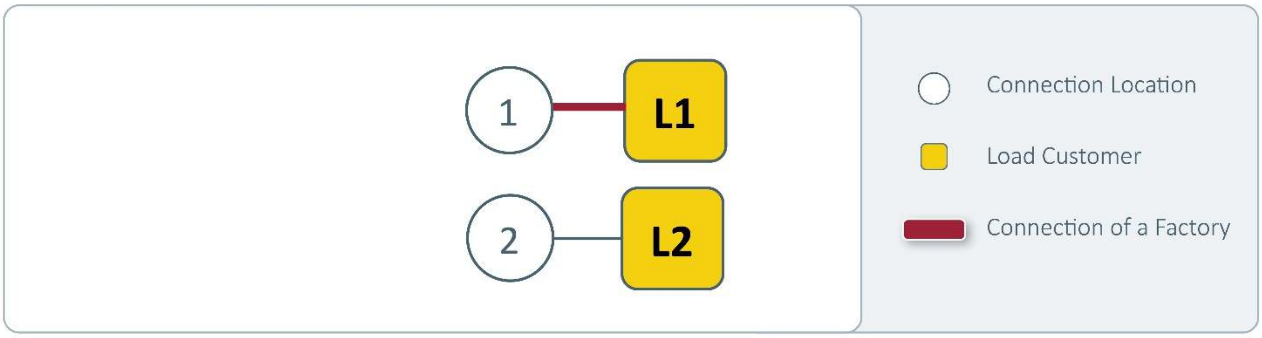
    86.3 residual charge step-change approach, as proposed by Transpower in its Checkpoint 2B submission (**Checkpoint 2B Approach**).

87. In comparing each the different approaches in the Worked Example, we have sought to demonstrate where there may be a competitive neutrality issue in adopting one approach as compared to another approach. We have done this by identifying any pricing year in which one customer has a "competitive advantage" over another customer. A competitive advantage arises where a customer pays a lower residual charge in a pricing year as compared to the residual charges payable by another customer in that pricing year operating an identical Factory. (We do not consider that there is a competitive neutrality issue that arises between two customers that are each subject to a lagged adjustment and paying different charges in a pricing year, for example L2 and L3 in the Authority Approach.)

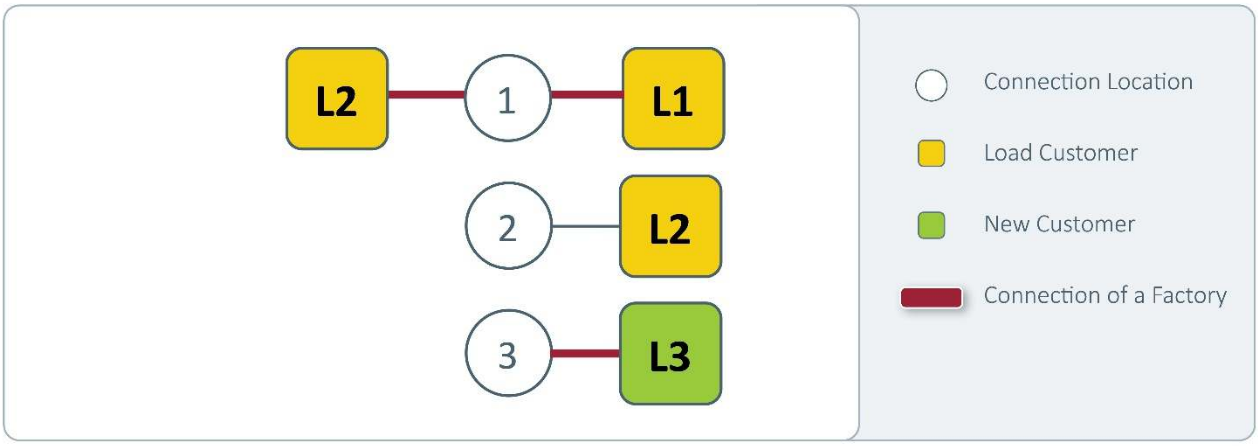
88. All capitalised terms that are not defined in this paper are as defined in the resubmitted proposed TPM.

8.1 Worked Example

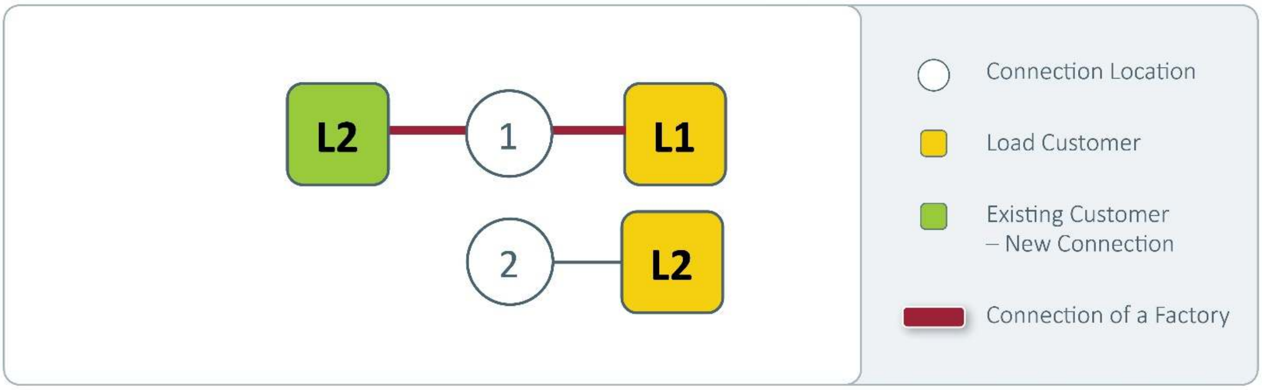
89. As of pricing year 2023, L1 has a Factory connected to the grid at connection location 1. It has been connected for 10 years. L2 is also connected to the grid at connection location 2.



90. In pricing year 2024, L2 (an existing customer) connects a new Factory at connection location



91. In pricing year 2027, L3 (a new customer) connects a new Factory at connection location 3:



8.2 Residual charge adjustment scenarios

Summary table

	30 June Approach	Authority Approach (lagged)	Checkpoint 2B Approach (step-change)
New entrant	92. Pays immediately	93. Lagged	94. Pays immediately
Incumbent connection new plant (or substantially increasing use or generation)	95. Lagged	96. Lagged	**97.** Pays immediately
Incumbent other increases	**98.** Lagged	**99.** Lagged	100. Lagged

30 June Approach

101. The 30 June Approach involves the following:

101.1 new load customers that connect to the grid would immediately be subject to a step-change so that it would pay a residual charge equal to the residual charge payable by other load customers with the same or similar type of assets (clause 91(2), proposed TPM); and

101.2 existing load customers that connect to the grid at a new connection location would have their residual charge increased only by way of the lagged adjustment (clauses 66 to 68, proposed TPM).

102. We consider that the 30 June Approach is consistent with the Guidelines.

103. Adopting this approach, then pursuant to the Worked Example:

103.1 As of pricing year 2023, and in each following pricing year, L1 has a residual charge of $100.

103.2 Upon L2's connection at connection location 1 in pricing year 2024, L2's residual charge with respect to its Factory connected at location 1 will be $0, and it will increase by way of the lagged adjustment until it reaches $100 in pricing year 2031.

103.3 Upon L3's connection at connection location 3 in 2027, it will immediately pay a residual charge of $100 and continue to pay $100 in each following pricing year.

104. Please see table below illustrating each load customer's residual charges:

PY	L1 residual charge ($)	L2 residual charge ($) (at connection location 1)	L3 residual charge ($)	Competitive advantage (CA)
2023	100	-	-	-
2024	100	0	-	L2 CA over L1
2025	100	0	-	L2 CA over L1
2026	100	0	-	L2 CA over L1
2027	100	0	100	L2 CA over L1 and L3
2028	100	25	100	L2 CA over L1 and L3
2029	100	50	100	L2 CA over L1 and L3
2030	100	75	100	L2 CA over L1 and L3
2031	100	100	100	No CA
2032	100	100	100	No CA
2033	100	100	100	No CA
2034	100	100	100	No CA

Authority Approach

105. The Authority Approach involves the following:

105.1 new load customers that connect to the grid (L3) would have their residual charge increased incrementally by way of a lagged adjustment. The Authority proposes that the customer's residual charge would increase incrementally as follows:

105.1.1 Up to and including year 4 following connection, $0;

105.1.2 In year 5 following connection, 25% of full charges;

105.1.3 In year 6 following connection, 50% of full charges;

105.1.4 In year 7 following connection, 75% of full charges; and

105.1.5 On and from year 8, 100% of full charges.

105.2 existing load customers that connect to the grid (L2) at a new connection location would have their residual charge increased only by way of the lagged adjustment as noted in paragraph 16.1 above (clauses 66 to 68, proposed TPM).

106. As per the Authority Feedback Letter, we agree that the Authority Approach would require a departure from the Guidelines by way of clause 2.

107. Adopting this approach, then pursuant to the Worked Example:

107.1 As of pricing year 2023, and in each following pricing year, L1 has a residual charge of $100.

107.2 Upon L2's connection at connection location 1 in pricing year 2024, L2's residual charge with respect to its Factory connected at location 1 will be $0, and it will increase by way of the lagged adjustment until it reaches $100 in pricing year 2031.

107.3 Upon L3's connection at connection location 3 in 2027, L3's residual charge will be $0, and it will increase by way of the lagged adjustment until it reaches $100 in pricing year in 2034.

108. Please see table below illustrating each load customer's residual charges:

PY	L1 residual charge ($)	L2 residual charge ($) (at connection location 1)	L3 residual charge ($)	Competitive advantage (CA)
2023	100	-	-	-
2024	100	**0**	-	L2 CA over L1
2025	100	0	-	L2 CA over L1
2026	100	0	-	L2 CA over L1
2027	100	0	**0**	L2 CA over L1 L3 CA over L1
2028	100	25	0	L2 CA over L1 L3 CA over L1
2029	100	50	0	L2 CA over L1 L3 CA over L1
2030	100	75	0	L2 CA over L1 L3 CA over L1
2031	100	100	25	L3 CA over L1
2032	100	100	50	L3 CA over L1
2033	100	100	75	L3 CA over L1
2034	100	100	100	No CA

Checkpoint 2B Approach

109. The Checkpoint 2B Approach involves the following:

109.1 new load customers that connect to the grid (L3) would immediately be subject to a step-change so that it would pay a residual charge equal to the residual charge payable by other load customers with the same or similar type of assets; and

109.2 existing load customers that connect to the grid (L2) or substantially increase their electricity use or generation would immediately be subject to a step-change so that it would pay a residual charge equal to the residual charge payable by other load customers with the same or similar type of assets.

110. As per our Checkpoint 2B submission, we consider that the Checkpoint 2B Approach would require a departure from the Guidelines by way of clause 2.

111. Adopting this approach, then pursuant to the Worked Example:

111.1 As of pricing year 2023, and in each following pricing year, L1 has a residual charge of $100.

111.2 Upon L2's connection at connection location 1 in 2024, with respect to its Factory connected at location 1, it will immediately pay a residual charge of $100 and continue to pay $100 in each following pricing year.

111.3 Upon L3's connection at connection location 3 in 2027, it will immediately pay a residual charge of $100 and continue to pay $100 in each following pricing year.

112. Please see table below illustrating each load customer's residual charges:

PY	L1 residual charge ($)	L2 residual charge ($) (at connection location 1)	L3 residual charge ($)	Competitive advantage (CA)
2023	100	-	-	-
2024	100	-	-	-
2025	100	**100**	-	No CA
2026	100	100	-	No CA
2027	100	100	-	No CA
2028	100	100	**100**	No CA
2029	100	100	100	No CA
2030	100	100	100	No CA
2031	100	100	100	No CA
2032	100	100	100	No CA
2033	100	100	100	No CA
2034	100	100	100	No CA
2035	100	100	100	No CA