Orion

30 November 2021

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

by email: TPM@ea.govt.nz
(subject line "Consultation paper – Proposed Transmission Pricing Methodology")

Response to consultation paper – Proposed Transmission Pricing Methodology

1. Orion New Zealand Limited (Orion) welcomes the opportunity to provide a submission on the Electricity Authority's proposed transmission pricing methodology set out in its consultation paper dated 8 October 2021.

2. We provide responses to the Authority's questions in the submission template attached to this submission. We also set out our key concerns, including areas that are not covered by the Authority's questions, in this letter. These concerns include:

   a. Gross load approach inconsistent with pricing principles

   b. Gross load will encourage behind-the-meter generation

   c. Allocating BBC to generators creates an inefficient incentive for embedded generation

   d. Batteries on the DC side of an inverter are not catered for

   e. Bill shock for individual customers

   f. Addressing the uncertainty of change

   g. The timing of this process has created additional uncertainty

   h. Non-distortionary pricing is difficult

3. We are concerned that there is some confusion around the use of the term "customer" to mean transmission customer, whereas many would take this to represent an end-use consumer. To avoid this confusion, and distinguish between the two, we refer to "distributors" and "consumers" in this submission.

4. We elaborate on each of these points in the following sections.

Gross load approach inconsistent with pricing principles

5. The proposed TPM uses "gross load" when allocating the residual charge between distributors and other transmission customers. Gross load is defined as GXP offtake plus embedded electricity (and we have been advised that embedded electricity is reconciled embedded generation injected into the distributor's network).

Orion New Zealand Ltd
565 Wairakei Road
PO Box 13896
Christchurch 8141
+64 3 363 9898
oriongroup.co.nz

6. Embedded electricity is not delivered by Transpower but the approach charges customers as if it were.

7. This approach conflicts with the distribution pricing practice note which promotes locational pricing, where assets that serve a customer are identified to avoid cross-subsidies[1]. The proposed TPM approach applies residual asset based charges to customers who are not using the assets.

8. The proposed approach is analogous to us asking a consumer if they use an alternative fuel source for heating, firewood for example, and then calculating an equivalent kWh and charging as if we had delivered that energy. In this respect, we do not think the approach is reasonable.

Gross load will encourage behind-the-meter generation

9. As gross load only includes embedded generation that is reconciled, when distributors look to reflect this charge they will simply encourage embedded generation to remain behind the meter. This has a number of inefficient outcomes that we are already seeing:

    a. Consumers amalgamate supplies to include more load that can be offset,

    b. Consumers invest in technology like batteries and hot water diverters, to maximise self consumption,

    c. Consumers invest in expensive technology like Solshare[2] to inject embedded generation into multiple properties, behind multiple meters.

10. The cost of these actions is inefficient because the action itself does not yield any underlying benefit.

Allocating BBC to generators creates an inefficient incentive for embedded generation

11. The approach to allocating benefits-based charges to generators creates a distortion between grid connected generation and generation connected to distribution networks. This will inefficiently incentivise generation to embed within distribution networks, and to match but not exceed the available load to offset.

12. It would be more efficient to seek approaches that provide similar outcomes regardless of the connection location so that generation opportunities are selected efficiently.

Batteries on the DC side of an inverter are not catered for

13. We agree with the Authority's objective to avoid double counting of energy that charges a battery, and then discharges to a load when allocating the residual charge. We further agree with the objective of including losses in the charge-discharge cycle when allocating the residual charge.

14. The vast majority of the batteries that our customers have installed are connected via the DC side of a solar PV inverter. It is efficient to make use of an inverter that is already in place, and it is efficient to charge batteries using generation without converting it to AC. As such, we expect that larger grid scale batteries will also be located on the DC side of grid scale solar farms.

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[1] Supporting reform to efficient distribution pricing: a refreshed Distribution Pricing Practice Note Consultation Paper 21 September 2021, paragraph 24.

[2] https://allumeenergy.com/

15. Distributors (and the reconciliation system) only have visibility of the energy that flows to and from an end consumer's installation. When a consumer is injecting to our network, there is no way we can know if that injection is from generation, from the battery, or from a combination of the two. Further, even where injection is from the battery, we will not know if that battery was previously charged from the grid or from generation, or from a combination of the two.

16. The situation is further complicated when there is a combination of generation, batteries *and* load all behind a single meter. We understand that several grid scale solar projects include load (such as data centres) or are being located adjacent to existing load to take advantage of direct connection to that load.

17. We don't think it is feasible, practical, or efficient to require customers to measure energy that flows in and out of their batteries, measure energy from generation, and measure load within their installation and provide this to the industry. Given this limitation, the measurements identified in the examples in the Consultation Paper will not be available, and the calculations cannot be carried out. It does not appear that the Authority will be able to implement its objective for the vast majority of battery installations.

18. Given that this limitation applies to the most efficient location of batteries, we are concerned that we should not place artificial barriers that may discourage batteries in these locations.

19. Unfortunately, we have not identified an alternative that achieves the Authority's objective. The root cause of this issue is the decision to use "gross load" in the allocation of the residual charge. As we have noted above, this effectively attempts to charge customers for the delivery of energy that Transpower did not deliver. Moving to a net load approach would avoid the issue altogether.

Bill shock for individual consumers

20. The proposed TPM includes a 3.5% cap on the amount that total electricity bills may increase. It identifies this as a mechanism to "prevent price shock on household and business customers". It then goes on to say that changes are modest, and the cap does not apply to any distributor. However, the cap does apply to other industrial transmission customers, which is not in line with the stated objective.

21. This occurs because distributors aggregate vast amounts of load which effectively reduces or eliminates the volatility seen in individual consumer loads.

22. When distributors look to reflect the new TPM in their charges to customers, the price shocks will not be avoided. In some situations, distributors will not be able to overcharge some customers in order to smooth the impact for others. Like Transpower, we too have individual consumers that have found ways to entirely or almost entirely avoid the RCPD charge.

23. This is an inevitable outcome of change. An alternative and effective mitigating approach is to transition to the new TPM over a period of time, progressively deweighting the RCPD and HVDC charge and replacing it with the new charge components over a number of years. With this approach the impact on individual customers is mitigated.

24. In the absence of a transition, we would like to see the Authority's material acknowledging the impacts that this will have on individual consumers when passed through, rather than the current presentation which suggests it isn't an issue. We would also like to see support for distributors to take approaches that smooth the impact for consumers (despite this being a departure from reflecting costs).

Addressing the uncertainty of change

25. The proposed TPM includes reassessments of benefit based charges when changes occur (for example, for new connections or where a distributor connects a large new load or generator). Customers making the investments that drive these changes need to know what charges they might face, and to provide this, distributors will need access to a process to estimate charges and impacts for various investment scenarios.

26. The TPM can only beneficially influence outcomes if the impacts are transparent. Uncertainty in this area will have an impact on investment decisions, with commercial and environmental impacts.

27. We would like to see a requirement for Transpower to assess the impact of proposals and provide guidance on the likely charges.

The timing of this process has created additional uncertainty

28. Right now we do not know if our current summer and winter peak loads might contribute to RCPD based charges from 1 April 2023, or if the RCPD charge will be replaced by that date (in which case current peak loads will have no influence on charges).

29. If we tell our customers they should continue responding, we might then not be able to reflect any reward, and the cost of responding will be wasted.

30. If we tell customers not to respond but the RCPD charging approach prevails, then the customers miss the opportunity to adjust their exposure and will face additional charges.

31. The Authority is encouraging Distributors to be cost reflective in our pricing to customers. Transmission charges are by far our biggest single cost, and the Authority's process for updating the TPM has left us in a position where we do not know the basis of charges.

32. We ask that the Authority consider changing its timeline for implementing the TPM so that the change can be signalled in advance of any period of loading assessment.

Non-distortionary pricing is difficult

33. We agree that it is efficient to recover residual costs in a way that does not distort consumer behaviour. The Consultation Paper notes that the current RCPD charge distorts the cost of transmission and uses this as a justification for change. It goes on to say that the residual charge has been deliberately structured to not create incentives that distort use or investment decisions.

34. We do not believe that the structure of the residual change in the proposed TPM quite achieves what the Authority claims. In our experience, structuring pricing to be non-distortionary is very difficult.

35. The proposed approach to adjusting the residual charge based on gross load will influence consumer behaviour. If we were able to pass through the proposed structure, then consumers will be exposed to the "residual charge adjustment factor" where a 1 kWh savings in year 1 will proportionally reduce their charges over years 6, 7, 8 and 9. With the current low interest rate environment, the savings, even where delayed, are attractive.

36. However, we are in a situation where we are not able to match the approach in the proposed TPM and charge consumers for their usage from 5 to 8 years prior. We must instead rebundle charges to reflect current usage. Based on Orion's estimated residual charge and gross energy volumes, we have calculated the NPV of the delayed savings as 1c/kWh. Reflecting the proposed TPM approach, we would apply this as a kWh volume price against all load volumes which would account for close to 15% of our annual revenue.

37. Areas where consumers act to reduce volumes will pay less, and areas that do not reduce (perhaps where the distributor elects to rebundle in a non-cost reflective way) will pay more.

38. Unfortunately, we do not have a solution to offer, but it is worth observing that the benefits claimed and the durability of the TPM are somewhat undermined by this distortionary incentive.

Concluding remarks

39. We submit that several issues in the proposed TPM will need to be addressed for it to become a durable solution.

40. Thank you for the opportunity to provide this submission. The material in our submission is not confidential. If you have any questions, please contact Dayle Parris on 027 399 9609 or dayle.parris@oriongroup.co.nz.

Yours sincerely

Dayle Parris
Head of Regulatory and Commercial

Consultation questions

Chapter 2 A new TPM	
	Do you have any comments on the content of this chapter?
Response	We question the "existing issues". The Authority's focus on short run marginal costs leads to a conclusion of inefficient response to RCPD signals. The alternative view is that long term pricing signals encourage a response in a very inelastic market, and that a response would otherwise not occur in the face of dynamically changing real time pricing. The observed volatility in RCPD charging could be addressed in a number of ways. The South Island focus of the RCPD criticised in the existing issues is an example of locational pricing that is identified as being needed in the very next issue. The HVDC is primarily used (and has been upgraded to support) flows from south to north, and the approach encourages efficient location of generation nearer load.
Chapter 3 Grid asset classification	
	Do you agree with the proposed approach to treat connection assets as interconnection assets for a limited time if the assets will ultimately be interconnection assets when fully commissioned? Do you agree with the proposed reclassification power? Should there be any further conditions on Transpower's use of this discretion? Do you have any other feedback on Grid Asset Classification in the proposed TPM?
Response	We agree that new assets that will ultimately be used as interconnection assets should be classified as interconnection assets during staged commissioning. We agree with the limitation on a third party's ability to convert connection assets into interconnection assets via their own investment to close a loop. However, when exercising its discretion, Transpower should have regard for existing situations (and prior investments) where assets have been categorised as interconnection assets in this way e.g. the possible future reconsideration of the connection status of a GXP that becomes a net injector from renewable generation or where the lines to a GXP are considered a spur and the GXP a connection asset.
Chapter 4 Connection charges	
	Do you agree that the proposed TPM should specify that connection asset replacement values be regularly updated to promote cost-reflective charges and certainty? Do you have any comment on the proposed approaches to address first mover disadvantage issues, including on: • the proposed FAC mechanism for Type 1 FMD • the alternative option of an upper limit on application of the benefit-based approach for Type 2 FMD • the approach to applying 'above-limit costs' under this alternative option? Do you have any other feedback on the proposed TPM in relation to connection charges?
Response	Connection assets drive largely historical connection charges, because new connection assets are funded through Transmission Works Agreements. The approach of leaving asset values unchanged is aligned with Transpower's depreciated historic cost regulation (DHC), where Transpower is given a WACC against the DHC which tends to front load the revenue stream. (Distributors are regulated differently – they attract an indexed depreciated historic cost

	approach, where asset values are indexed (to broadly align with changing value over time), but this indexation must be deducted from the WACC before it is applied.) Also, it is not clear to us that values will change differently at different locations, so the allocation of connection charges might not change much as a result of any asset value review. In the absence of a compelling reason to add complexity, and to avoid a departure from the building-blocks IPP approach, it may be better to retain the current approach. We agree that a cable maintenance cost should be added. For Type 1 FMD, we do not consider that there is a competition issue with the proposed mechanism. The incentive that the first mover has in adding additional generation is simply the incentive to more efficiently utilise assets that it has already funded. In the event that another party utilises those assets it is appropriate that it faces the costs and prior costs. Trying to avoid this outcome would simply re-create the first mover disadvantage. For Type 2 FMD, we agree with the Authority's proposed approach of allocating the cost of anticipatory connection investments on a benefits basis. Of particular note, we believe this will result in more efficient decisions on oversizing than might occur if the costs were socialised more widely, and beyond the area of benefit.
Chapter 5 Benefit-based charges: allocation	
	Do you have any comment on the proposed standard and simple benefit-based allocation methods? Do you have any comment or additional evidence on the proposed weighting of benefits between load and generation customers under the simple method, or with respect to the proposed review of the allocation?
Response	As noted in our previous submission to Transpower on the benefits based charge allocation, we are concerned that assessments for successive upgrades will lead to a complex entanglement of benefit based assessments. This will undermine the purpose of the TPM in that the pricing outcomes for proposed upgrades will become very uncertain which will not drive efficient outcomes. The 50:50 weighting between load and generation appears arbitrary, and the ability to change it creates uncertainty (mainly for those considering generation investments). All costs ship home to consumers, one way or another, and we would like to see more work done on which route provides more efficient outcomes. If we can show that applying charges to load customers only provides efficient outcomes, then all charges should be applied to load customers (and vice versa).
Chapter 6 Benefit-based charges: covered costs	
	Do you have any comment on the proposed approach to covered costs, including on: • whether overhead opex should be recovered through the BBC or residual charge, and any evidence to support your view? • the recovery of opex on fully depreciated assets through the residual charge?

Response	We agree with the proposed approach to recover overhead opex that is reasonably attributed to the BBI[3] should form part of its recovered cost, rather than socialised more widely via the residual charge.

Chapter 7 Residual charges

	Do you have any comment on how the proposed TPM implements the residual charge provided for in the Guidelines? Do you agree with the application of the residual charge to generation with embedded load, or can you suggest a better way to mitigate charge avoidance incentives and risk of an uneven playing field? Do you have any comment on the proposed approach to application of the residual charge to battery storage to avoid double-counting of load?
Response	Please refer to our comments in our cover letter regarding the residual charge. In particular: a. Gross load approach inconsistent with pricing principles b. Gross load will encourage behind-the-meter generation c. Batteries on the DC side of an inverter are not catered for d. Bill shock for individual customers These concerns and concerns with the use of gross load as an allocation adjustment aside, we support the netting off of grid injection due to generation imbedded in a distribution network in the calculation of gross load.

Chapter 8 Adjustments

	Do you agree with or have any other feedback on the proposed provisions for adjusting transmission charges? The Authority welcomes feedback on any aspect discussed or proposed in this chapter, including whether: • the proposed TPM should provide more detail on the method for determining new entrants' benefits • the charges for a new entrant should be the same as an equivalent incumbent each year (as in the proposed TPM), on a whole-of-life basis as in the Guidelines • the proposed thresholds for 'large' and 'substantial sustained' change in grid use are appropriate • the connection of a distributor to a new (and additional) GXP and the upgrading of a transformer at a distributor's GXP should be adjustment events • the plant disconnection provision should be extended to plant de-rating • the relevant provision should be further extended to cover a substantial sustained decrease in grid use not related to a plant disconnection or de-rating • the residual charge for a new entrant and an expanding customer should adjust with a lag and a gradual ramp-up, as proposed • the proposed 'related entity' provisions deal appropriately with avoidance concerns, and whether there is a case for a broader or more general 'related entity' provision to deal with other, potentially unforeseen, avoidance opportunities?
Response	We agree that where a new GXP is commissioned to meet a large new load the benefit based allocation should be reassessed. However, where a new GXP is commissioned to meet

[3] Benefits based investments

incremental growth and relieve load on adjacent constrained GXPs or subtransmission networks, a reassessment may disadvantage the distributor. To avoid this, any reassessment should ensure it aligns the timing of demand (in much the same way that a new house is given a backdated rateable valuation to align it with the date other rateable valuations were struck).

The substantial and sustained trigger for change is pegged at an increase of 25% energy consumption. This could lead to a significant number of reviews where load is transferred between GXPs. For example, where a new GXP is established, load will be progressively transferred to the new GXP over a number of years as feeders on adjacent constrained GXPs are transferred. We would like to submit that Transpower does not carry out an adjustment where it reasonably considers that in the absence of load shifting by a customer, the movement would not have exceeded the 25% trigger.

Chapter 9 Prudent discounts

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

- Transpower should have to prepare a PD practice manual, and if so when, and should it be binding on Transpower
- 15 years should be the default maximum period with a longer term possible on proof
- prudent discounts should be funded via the residual charge and as appropriate the benefit-based charge
- customers should be able to terminate a prudent discount agreement before the end date of the agreement?

Response — No comment.

Chapter 10 Transitional congestion charge

Do you have any feedback on the proposal not to include a TCC in the proposed TPM, for the reason that widespread risk of congestion from removing the RCPD charge is unlikely and that, if necessary, the grid owner and system operator have effective tools to manage the power system quickly and efficiently?

If not, how should a TCC be designed to be consistent with the Guidelines? Under what situations should it be applied and how should its size and allocation be determined?

Response — We support the proposal to not include a TCC in the TPM. The reason we do not wish to see a TCC is because the TPM guidelines set it out as an additional charge that will penalise areas with a constraint that are experiencing a lower level of service and must incur the cost of DSM activities.

If it is reinstated in future, it should instead be structured as a congestion credit, where customers that help alleviate the need for an upgrade are rewarded with lower charges (reflecting the lower cost of deferring the upgrade) and this is funded by a socialised increase in the residual charge (reflecting the fact that the pool of residual assets is likely smaller as a result of the responding customer's ongoing DSM).

Chapter 11 kvar charge

Do you have any comment on the proposal not to include a kVAr charge in the proposed TPM?

Response — No comment

Chapter 12 Indicative prices	
	Do you have any comments on indicative pricing or the application of the transitional cap?
Response	Please see our comments in our cover letter regarding the impact on individual consumers when a non-phased abrupt change is made to the TPM.

Chapter 13 Other provisions of the proposed TPM	
	Do you have any comment on or suggestions for the preliminary provisions cl1-18?
Response	No comment.

Chapter 14 Regulatory statement	
	Do you have any comments on the regulatory statement, or the assessment of wider factors?
Response	No comment.

Chapter 15 Next steps	
	Do you agree that 1 April 2023 is an appropriate commencement date for the proposed TPM? Do you agree with the proposed transitional measure for any standard method investments for which allocation is not completed?
Response	Please see the comments in our cover letter regarding the uncertainty that this process has created. The Upper South Island is currently in an RCPD assessment period and we do not know if the coincident peak loads will drive future costs.

Appendix: Proposed TPM	
	Do you have any feedback that would improve the drafting of the proposed TPM?
Response	No comment.

Appendix: Cost benefit analysis	
	Do you have any comment on the cost benefit analysis?
Response	No comment.

Other	Is there anything else in relation to the proposed Code amendment that you wish to comment on? Do you have any other feedback on any other aspect of the proposed TPM?
Response	No comment.