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Submissions
Electricity Authority
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POWERCO – Submission on *2019 Transmission Pricing Review – Consultation Paper*

Thank you for the opportunity to submit on the Electricity Authority's consultation paper.

To support decarbonisation, a durable TPM must accommodate changes to the form and use of the grid over time

The core aspects of the Authority's proposal are the benefit-based charge and the residual charge. Additional mechanisms have been included to manage transition issues eg a 3.5% price cap and a transitional peak charge. The lens we've applied for our submission is how the proposal might work in practice[1], and is therefore guided by two principles:

- **Neutrality** about how technology types, investments, and customer definitions are defined. For example, if generation is to be allocated a transmission charge, then all forms of generation should be treated equally.
- **Flexibility** to be robust as future grid use and investment changes, as we know it will. For example, are the beneficiaries and shares for the various HVDC upgrades the same as they were when the investments were originally proposed?

These principles matter because the current TPM has struggled to adapt and accommodate to changing demand and supply, as demonstrated throughout the Authority's consultation paper. More broadly, potential decarbonisation pathways suggest a range of possible impacts on transmission investment requirements. The TPM must anticipate and accommodate this. The Authority comments that "perfection is not a necessary feature of cost allocation". We suggest the Authority adopt the same ethos when thinking about the guidelines. It's impossible for the Authority and the industry to assess and cater for every possible impact and circumstance in the initial design.

[1] Our previous submissions have essentially: supported a transmission charge for all assets charged to load, presented concerns about the benefits-based charge (exceeding private benefits and overly sensitive to arbitrary assumptions), and queried the cost-benefit analysis. The Authority has a different view on these key issues eg footnotes 121, 123. We have not developed additional evidence on these topics, so have chosen to focus on some practical elements of the proposal.

Our view on the components of the TPM and the process to deliver it are:

Benefit-based charge	• Apply the same identification process eg $50m for all transmission assets and ensure charges don’t exceed net benefit. • The mechanism for estimating the benefit shares needs to be robust, consistent across all investments, and repeatable. • A gross load approach would treat distributed and grid-connected generation equally given they both access the wholesale market which the grid supports. A level playing field is important given the role of generation to support increased electrification from decarbonisation. • Update the benefit shares periodically eg at each Transpower reset, to avoid deviations of estimated and actual benefit shares. This would also align with other changes to transmission costs eg WACC, revenue smoothing.
Residual charge	• Allocate the residual based on historical AMD that nets off all forms of generation and demand-side response ie assess peak demand consistently. • Systematically updating the residual allocations for all legitimate changes to AMD (up and down) will be more robust than a ‘trigger’ approach
Ancillary mechanisms	• Retain the 3.5% price-cap approach and perform it at a more granular level for distributors eg at the GXP or zone. For context, recent WACC determination will have ~10% reduction in distribution revenue requirements: this ‘known mechanism/unknown outcome’ issue is managed by parties as business as usual. • Retain the peak charge as a permanent tool which can be flexed (both structure and price level) as needed
Process	• The indicative timeframe for Transpower to implement the proposal needs more flexibility to allow for insights/problems that arise during the process of building it. • The Authority and Transpower must agree the implementation timeframe as co-sponsors of this change project – you’ve both got a hand on the steering wheel.

We’ve provided general comments in Attachment 1, and comments about the guidelines and related specific questions in Attachment 2. If you have any questions about this submission, please contact Andrew Kerr (Andrew.Kerr@powerco.co.nz).

Yours sincerely

Stuart Marshall
General Manager – Regulation and Commercial

Attachment 1: General comments

Implementation (Chapter 6)

The indicative timeframe for Transpower to implement the proposal needs flexibility to allow for insights/problems that arise during the process of building it. We think the Authority and Transpower need to agree the timeframe as co-sponsors of any systems project would. Many details are still to be decided – either by the EA in specifying the guidelines or by Transpower via further consultation. These can't be avoided. And there are interdependencies between the various components that will not be known until the parameters are fixed. Transpower will also be significantly enhancing its pricing capability compared to current requirements. It would have been difficult to predict a timeline of the Authority's TPM development (and hold the Authority to it). We should learn from that experience and apply a pragmatic approach to Transpower's implementation process. It'll take the time it takes, and it's worth taking the time to get it right.

Pass-through of fixed allocations/charges and the Low Fixed Charge regulations

If transmission charges are levied on distributors in a fixed way, the Authority must work with distributors and Government to address any issues restricting and distorting the ability of distribution prices to reflect them. The link between transmission prices and consumer decision making is an implicit and important assumption in the Authority's analysis. For direct-connect customers, load, generation, and investment decisions will face clear and separable signals from energy and transmission services. For customers connected to distribution networks, it's more complicated: transmission charges are bundled with distribution and retail charges which are in turn impacted by the Low Fixed Charge regulations. The Authority acknowledges this in B.229 in the context of the residual charge. The allocation of the benefit-based charge is also affected in the same way.

Clarifying changes to the ACOT regime (Code change 2 in Appendix F)

We support a change to Part 6 of the Code to clarify the role of ACOT payments from distributors to distributed generation. This will ensure Part 6 is independent from the current and future design of the TPM and allow distributed generation to compete on a level playing field with other forms of generation. The Authority noted this point in the 2016 review of the Distributed Generation Pricing Principles (DGPPs):

> *Transpower should also recommend to the Authority further adjustments to the ACOT arrangements that will promote efficiency and competitive neutrality between demand response, distributed generation and grid-connected generation*

The Authority's rationale for amending the DGPPs was that they incentivised connection of distributed generation to capture transmission savings in circumstances where Transpower did not avoid any costs. We have always expressed the view that the change that needed to be made to address the inefficiency of ACOT payments was to the TPM itself rather than the Code. So we welcome the porposed alignment of the TPM and the DGPPs. We agree that the approach under the TPM is more consistent with the stated intention of ACOT payments than was previously the case.

For the proposed code change, a small typo correction is needed to 2(a)(i), which refers to a "benefit-based charge" rather than the "area-of-benefit" charge.

Food for thought is whether clause 2(a)(i) is needed at all under the proposed TPM. A neutrality principle suggests no individual technology (like DG) should get different treatment to other technologies that provide the same service (if they do). This avoids the possibility that consumers on a distribution network pay for DG services which extend beyond the network (as reflected by the design of the prices). Note: we haven't worked through the linkages between the TPM and market mechanisms fully.

Attachment 2: Comments to the draft guidelines and associated settings

Our comments about the guidelines and settings have been grouped according to the structure of the draft guidelines (Appendix A). References like 3.20 and B.59 relate to paragraphs in the consultation paper, references like Q30 refer to the specific questions in the consultation, and references like G10 refer to the numbered guideline paragraph.

Because of the interdependencies between the different components of the TPM and their underlying settings, it's remarkably difficult to provide answers in a separable manner. For example, if the price cap stays in place, then the approach to thresholds for assets subject to the benefit-based charge might change.

Guideline topic area and clause	Comments
Policy Objectives	For the residual charge purpose statement, the phrase "…in a way which does not affect designated transmission customers' decision-making" should be less definitive. A phrase like "minimise inefficient decision-making" might be appropriate, realistic, and align with the tone of the purpose of the cap on transmission charges (see B.196 which refers to the residual charge "… not intended to actively influence grid use and investment".
General matters and main components (G1-9)	**GL1a-1b** Minor drafting note. The flows between 1(a-b) needs some tweaking to get the flow correct. One option is to combine (a) and (b) to read "Set charges in a way that reflects the cost of providing designated transmission customers with:" **G5** The text after 5(e) allows for Transpower to not repeat a consultation on the benefit/residual charge, parameters, material changes, and assumptions if it can demonstrate that affected parties have been consulted prior. This 'test' should be included in the consultation process rather than being an ex ante assessment – if all stakeholders have agreed then it should be a short consultation. **G7** For the price signal to be an effective incentive (see B.20) consumers connected to distribution networks there will need to be a strong link between the benefits, transmission costs, and the allocation of those costs in the preparation of distribution charges, and the representation of the distribution charge in the retail charge. **G8** As above – a subset of a distributor's customers may benefit from a non-transmission alternative, so the allocation needs to be made in a way that reflects this. **Q10** Treating transmission investments and alternatives in a consistent manner means considering the location of where the benefits and costs lie at a more granular level than distribution customer. Powerco's network ranges across the North Island, so any methodology needs to take geographical location in to account consistently across all aspects of the TPM. This might be the intent of the guidelines – for the avoidance of doubt we are raising it.
Main component 1: connection charge (10-11)	
Main component 2: benefit-based charge (12-38)	**Q13**: A benefit-based charge will potentially promote the EA's statutory objective. The industry's analysis (including the EA's) over recent years indicates that there are several ways to link cost allocation and investment signals.

	Footnotes 121, 123, and 173 suggest the EA's position on the merits of a benefit-based approach is well considered. The approach is missing a test to limit charges to be less than a customer's net benefit. **Q15** We're comfortable with the concept that the TPM aligns with Transpower's current revenue requirement. A value threshold of $50m is pragmatic, though we think this should apply to all assets. If benefit-based charges are set to be below net benefit, any residual can be allocated by the residual. This also means that large investments can move in and out of the benefit and residual pools. **Q18** A neutrality principle suggests a gross-load approach as it treats generation consistently, regardless of how it connects to the grid (directly or via a distributor). Distributed and grid-connected generation both benefit from the spot market and the grid that underpins it, so it seems odd to differentiate distributed generation from the pool of beneficiaries via a 'net load' approach. We do not support a flexible approach. Using one approach avoids judgement calls which will favour some parties depending on whether a net or gross approach favours them (as will probably be reflected in the responses to this question from submitters). Pick one and use it consistently. If a change from/to net/gross.is proposed in future, it should be done unilaterally and be forward looking. This is an option for an operational review at some point in the future. **Q19-20** A $20m threshold for high/low investments is sensible given the alignment with Part 4 regulation. The threshold could be lowered in the future via an operational review once the approach has been demonstrated to be workable. This presumes that the benefit allocation could change through time too. **Q21** The threshold depends on the ability to attribute the benefits to a set of users. **Q22** Our preference is for an evidence-based approach that is repeatable, which favours VSPD over the "approximate regional" approach. Is there a middle ground which combines the two? **Q23**/**G26** While we can see the Authority's intent, it will remain be contentious and not durable? What is immaterial to one customer is significant to another. Instead, we suggest that the benefit costs and shares are recalculated every 5 years to align with Transpower's IPP process, updated grid investment test scenarios, and changes to WACC. This broadly aligns with the process distributors follow by aligning their prices to the cost of supply. If the approach to measuring the benefits via VSPD or some other method is robust, then there should be no aversion to re-running it. The overall impact would be to improve predictability (of process) and durability (by parties knowing that the alignment between costs and benefits won't ever get out of kilter). It is difficult to see how the proposed approach to fixed shares to customers would address the HVDC issues as described in B.59-61, and in B.147. The essential part of that discussion is "…the beneficiaries of the HVDC are now broader than the beneficiaries that were contemplated when it was originally decided …"

	The beneficiaries of transmission assets will change through time – if a benefit-based charge is to be used, its design must account for this, and the simpler the better because changes in benefit shares will happen again. The reassignment provisions implicitly acknowledge this – an alternative is to recalculate benefit shares a periodic exercise rather than by a trigger mechanism.
Main component 3: residual charge (39-41)	**Q27** The guidelines should allow for a flexible structure which can be modified. If a single charge is used, Transpower need only explain the rationale. This would give the payers of these costs the comfort that they are only paying for costs that cannot be attributed to a single or group of customers. **Q28/29** A historical AMD allocation is intuitive given it is a driver of transmission investment and is a likely/natural metric used by distributors to allocate the cost to customer groups in their networks. **Q30** We support non-coincident peak. Intuitively, AMD for GXPs in a similar region should be grouped together because they will benefit equally or similarly from the grid. **Q31** AMD should be measured in a way consistent with Transpower's assumptions about peak demand in its grid investment tests. **Q32** Gross load should be technology neutral, and therefore treat DG, behind the meter generation, load control, and whatever new technologies surface, as the same. A simple method can be used to estimate these impacts if actual data isn't available. **Q34** We suggest the Authority's allocation be a default which can be updated/corrected by Transpower as needed up to the point of implementation. **Q35** Yes, the allocation should be flexible through time for both increases and decreases. For distributors, the "substantial change" condition might need to be relative to a regional or zonal demand level rather than their total demand to align with the mechanism used to allocate the residual charge to distribution charges. For example, • a distributor has 2 networks with demand at A of 80MW and B of 20MW (=100) and the load drops to 80/10 (=90). • The impact of the 10MW is only 10% drop in AMD might not be considered substantial at a total network level so the residual charge stays at $X. • But the distributor must now allocate the same $X across a lower demand of 90 (80/10). To keep A whole, demand in B is allocated the residual 20% of X, but only spread across a demand of 10. The residual charge will be large for the foreseeable future. Powerco's residual charge is almost 90% of the total transmission charges. So it's important to work through AMD varies across the country and the residual is intended to reflect the cost of the grid to the customers who are still using the grid (new and old) then **Q36** the residual charge should apply to load (consistent with our previous submissions).
Provisions relating to adjustments (42-45)	

<table>
<tr><td>Main component 4: prudent discount policy (46-47)</td><td></td></tr>
<tr><td>Cap on transmission charges
(49-53)</td><td> Q39 The 3.5% price cap is a useful mechanism to manage outliers that results from the overall pricing process. We suggest the price cap should be retained given that changes to allocations through time might result in a breach of the 3.5%. The level of the cap could be changed as part of an operational review process.
In terms of how the analysis is done, we suggest it is performed at a more granular level than transmission customer eg GXP level. For example, The Authority's modelling suggests Powerco's customers will have a -2% reduction in overall energy charges. We've looked at this at various levels of disaggregation, including making first cut estimates about the allocation of transmission charges to customer groups. This modelling indicates that the ranges from

0% to -3% across zones
-6% to +4% across GXPs
-9% to +6% across customer groups (within GXPs – assumes an allocation to distribution prices and no barriers to the level of fixed/variable charges)

Upshot: The impact on individual price changes is lost when costs are assessed across multiple GXPs eg larger EDBs. Applying the neutrality principle suggests that the price cap impacts for particular zones or GXPs should be treated equally and independently of network ownership (similar to how direct consumers are modelled individually). For context, the transmission charges allocated to some of the individual GXPs on Powerco's network are higher than the total transmission charges allocated to some of the smaller distributors.
To reflect this in the guidelines, the parameters B, C, P, L, T and V would have a geographical index added.
Q42 The proposed approach to funding the price cap is reasonable. </td></tr>
<tr><td>Additional components
(54-65)</td><td> Q44/45 We support the inclusion of a peak charge because it will provide another tool for parties to manage peak load under a new TPM (as noted in B.315-317). Powerco does not use ripple control in a systematic manner to shift transmission charges to consumers on other distribution networks. So we do not anticipate the concerns expressed in B.311 to apply to us.
Q46 We support the need for the peak charge being a permanent tool. Transpower can set the level of the charge at zero if it is not needed. </td></tr>
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