2 December 2021

Submissions
Electricity Authority
PO Box 10041
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By email: TPM@ea.govt.nz

2021 Proposed Transmission Pricing Methodology (TPM)

1. Electricity is the key enabler to meet New Zealand's decarbonisation objectives. To this end, it is essential that transmission and distribution costs are kept as low as reasonably possible. In our view, the overall size of transmission costs is the primary issue, with the allocation of transmission costs a secondary issue.

2. Many of Contact Energy's primary concerns relate to the overall size of transmission costs and sit outside the TPM. In our view, the Government's ownership expectations of Transpower should be less about using a 100% government-owned natural monopoly to deliver relatively high annual dividends at minimal risk, and more about delivering low-cost electricity transmission to promote broader aspirations around economic development and decarbonisation. The Crown has consistently received a higher dividend pay-out as a proportion of its equity stake than the average pay-out of shareholders across the four `largest generators over the last decade.

3. One way to align Transpower's operations with the Government's long-term societal objectives is to apply a return to Transpower for both its regulated and non-regulated assets that more closely reflect the government's social rate of time preference. A return of 2% - 3% would better reflect the long-term benefits of the services Transpower provides than the current regulated WACC of 4.57%.

4. In terms of our submission, we have assessed the proposal against the same principles we have used to evaluate earlier versions of the TPM:

   - Durability and predictability;
   - Incentivising non-avoidance;
   - Cost reflection;
   - Efficiency; and
   - Simplicity.

5. We have been pragmatic when applying these principles given the challenging subject matter and we welcome many of the improvements to the Transmission Pricing Methodology (TPM) proposal. Specifically, we acknowledge and support the Authority's

efforts to address the following:

- the treatment of grid-connected batteries under the residual charge;
- the introduction of a stand-alone cost limb to the prudent discount policy; and
- the lagged approach to new customers under the residual charge.

6. While we support the general thrust of the TPM, we have some concerns over its complexity and how electricity lines businesses will pass through transmission costs to load customers. More generally, we are concerned that stakeholders are unable to calculate with any certainty or precision what transmission charges will be prior to making a major investment decision. In our experience, this uncertainty has deterred potential new load customers from making the transition from coal-fired to electric boilers.

7. Our submission sets out our priority recommendations including:

    - **Recovery of Transpower overheads through the residual charge**– consistent with the Authority's position in the 2019 *Issues Paper,* the 2020 *Decision*, and 28 July 2021 *Refer back letter to Transpower*, we consider Transpower's corporate overheads should largely be recovered through the residual charge (except for the existing injection overhead component of connection charges).

    - **Weighting of benefits between load and generation under the simple method** – our analysis suggests that the relative net private benefits of low-value investments between load and generators warrants an allocation of benefit-based charges under the simple method much closer to a 75:25 basis than the 50:50 basis proposed.

    - **Application of transmission charges after plant closure** – we remain concerned that transmission customers will continue to face transmission charges for a large plant that has closed. In our view, transmission charges should only apply for services rendered. Once a large plant has closed it is no longer drawing electricity from the grid and the transmission customer should not, in our view, continue to be liable for the benefit-based charges for benefit-based investments commissioned within the last 10-years. The argument put forward by the Authority to justify this policy position is that a transmission customer may have an incentive to close a large plant to avoid transmission charges. We consider this argument absurd given the magnitude of any decision to close a large plant, both in terms of personnel affected and remediation costs incurred. Similar arguments apply to large deratings of plant, or the closure or large derating of embedded generation.

    - **Direction to electricity distribution businesses required** – we are concerned that the incentives provided under the TPM may be lost if local lines companies simply average out transmission costs to new and existing customers, rather than the incremental transmission costs to new customers. We strongly encourage the Electricity Authority to be clear that they expect local networks to reflect the lagged residual charge in the pass through of transmission charges to new customers.

8. We have reviewed the proposal in detail and are happy to discuss and provide further information on any of the matters raised in this submission.

9. If you have any questions, please contact david.buckrell@contactenergy.co.nz or myself.

Yours sincerely,

Chris Abbott
Acting Chief Corporate Affairs Officer

Contact Energy TPM response

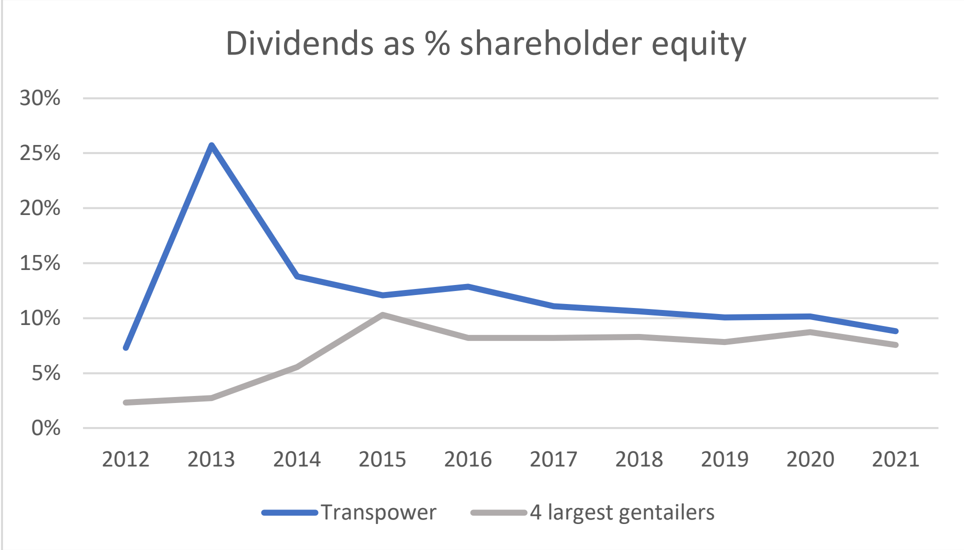
Our recommendations below will help deliver a TPM that better meets the Authority's statutory objective.

TPM Proposal	Contact Energy	Recommendation
Chapter 2: a new TPM		
Do you have any comments on the content of this chapter?		The issues around the current TPM and the need for change have been traversed for over a decade. We support the need for change and the basic tenor and structure of what the Authority is proposing. However, we are concerned with the complexity and uncertainty of the new regime. The inability of stakeholders to calculate with any accuracy or certainty what transmission charges will be for them prior to a new investment creates its own source of inefficiency. This is in stark contrast to the clarity and certainty of the Levelised Cost of Energy (LCOEs) of new renewable generation and associated Power Purchasing Agreements (PPAs). Transmission costs are a material cost factor in the economics of converting a coal-fired boiler to electricity. We have already seen potential customers make the decision to continue with coal rather than convert to electricity due to the uncertainty over future transmission costs under the new TPM. We note with some concern that some policy decisions that have been extensively consulted on and decided by the Authority have changed in this latest round of consultation. The most notable example is the proposal to recover the bulk of Transpower's overhead costs via the benefit-based charge rather than the residual charge. In our view, the interpretation of the Electricity Authority's statutory objective properly resides with the Authority (as the policy arm of transmission pricing regulation) and not Transpower (the operational arm of transmission pricing). To the extent the Authority has expressed its view in multiple consultations and correspondence as to how its statutory objective should be interpreted, we consider it inappropriate for Transpower to reinterpret that in a completely different manner. We list the other substantive reasons for our concerns at this policy change in the relevant section below. We believe that there is still time to correct these issues.
Chapter 3: Grid asset classification		
Do you agree with the proposed approach to treat connection assets as	Support	We support treating connection assets as interconnection assets for a limited time if the assets will ultimately be interconnection assets when fully commissioned. This will avoid circumstances where staged commissioning would be efficient but be opposed by customers reluctant to pay connection charges in the short term.

TPM Proposal	Contact Energy	Recommendation
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?	Support	We recognise that there will be instances where anomalous situations arise even when the policy intent is clear. In these circumstances, it is appropriate that Transpower be provided with the discretion to administer the rules to achieve the policy intent.
Do you have any other feedback on Grid Asset Classification in the proposed TPM?		None.
Chapter 4: Connection charge		**(Sections 11– 12 of the Guidelines)**
Do you agree that the proposed TPM should specify that connection asset replacement values be regularly updated to promote cost-reflective charges and certainty?	Support	Replacement costs of connection assets determine the share of overall costs apportioned to each asset. It is appropriate that these replacement costs are updated at least every five years. We are unsure as to whether regular updates to the replacement cost values of interconnection assets currently occur but think they should be if they aren't.
Removal of the injection overhead component	Change	We do not support the related proposals to remove the injection overhead component of connection charges for injection customers and instead recover a portion of Transpower's overhead costs through the benefits-based charge. We prefer that the status quo be retained. We consider it inappropriate to propose making a change of this magnitude at this late stage with no prior consultation or discussion.

TPM Proposal	Contact Energy	Recommendation
		We note that this is the first occasion where this proposal has been put out to consultation. Making material policy changes at this late stage where the Authority has previously articulated a different policy intent on multiple occasions is unjustified. The Authority argued in the 2019 *Issues Paper* that Transpower's overhead opex, for which a closer direct or causal relationship with a benefit-based investment cannot be verified, should be recovered through the residual charge. This position was reiterated in the 2020 *Decision* and 28 July 2021 *Refer back* letter. Transpower did not consult on this measure in its August 2020 *Connection charges consultation paper* or its November 2020 *Benefit-based charge consultation paper*. The first time this proposal appeared that we are aware of was in its June 2021 *Reasons Paper* submitted to the Authority. Separately, Transpower observed in its June 2021 *Reasons Paper* that customers were generally satisfied with the way connection charges work currently. We agree.
Do you have any comment on the proposed approaches to address first mover disadvantage issues, including on the proposed Funded Asset Component mechanism for Type 1 First Mover Disadvantage?	Support	The Authority and Transpower have introduced a sensible response to address the free-riding problem of first movers bearing all the capital costs of a connection asset even if other customers later connect to the asset. This response involves collecting a financial contribution from second and later connecting parties towards the capital cost of the connection investment that was funded by a first mover customer. The contribution would occur via a component added to the connection charges, paid by second and later parties, and rebated to the first mover. This approach is described as a "funded asset component" (FAC) mechanism. We do not perceive any potential competition concerns in the market for generation development. The FAC mechanism being proposed is agnostic as to the type of generator (or load customer) that connects first or who subsequently connects to a connection asset. While not explicitly covered, some consideration should also be given to interconnection assets. To avoid future transmission bottlenecks (which in some cases are predictable), some interconnection assets should be oversized initially. For this reason, we consider that benefit-based charges for a new entrant should be based on the whole-of-life expected benefits it gets compared to incumbents rather than the proposal to allocate charges that an equivalent incumbent would pay in the same year (see relevant section below). We are unclear whether adopting the "whole-of-life" approach to new entrants will, on its own, be sufficient to incentivise Transpower to oversize some interconnection assets to avoid future transmission bottlenecks. This is an area we think merits further consideration.

TPM Proposal	Contact Energy	Recommendation
Do you have any comment on the proposed approaches to address first mover disadvantage issues, including on: • 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?	Change	The Type 2 First Mover Disadvantage occurs when Transpower overbuilds a connection asset, either in whole or in part, in the expectation that other customers will come along, or the first customer will increase its capacity requirements in future. In the meantime, the first customer pays for the full capacity (capital, maintenance and operation). We see this issue becoming increasingly material as the country seeks to decarbonise through increasing levels of decarbonisation. To help address this issue, we believe the best option would be for Transpower and its 100% government shareholder to take on a small amount of additional risk. In our view, the Government's ownership expectations of Transpower should be less about using a 100%-owned natural monopoly to deliver relatively high annual dividends at minimal risk, and more about delivering low-cost electricity transmission to promote broader aspirations around economic development and decarbonisation. As shown in the graph below, the government has consistently received a higher dividend pay-out as a proportion of its equity stake than the average pay-out of shareholders across the four largest generators over the last decade.

TPM Proposal	Contact Energy	Recommendation
		 One way to align Transpower's operations with the Government's long-term societal objectives is to apply a return to Transpower for both its regulated and non-regulated assets that more closely reflect the government's social rate of time preference. A return of 2% - 3% would better reflect the long-term benefits of the services Transpower provides than the current regulated WACC of 4.57%. An alternative to funding anticipatory investment from other existing grid users would be for the government to fund these investments directly, much like it did for much of the costs of the Roads of National Significance. The Authority alludes to this approach in paragraph 4.48 of the consultation paper. Within the framework of the TPM, we prefer Transpower's recommendation of pooling and sharing to the various benefit-based options the Authority has put forward. The principal reason for our preference for pooling and sharing relates to its simplicity. We see the alternative benefit-based options as being overly complex and therefore unlikely to elicit the stakeholder interrogation of anticipatory investments that the Authority assumes. We also consider the proposed 50:50 allocation of benefits between load and generation under the simple method to be such a poor

TPM Proposal	Contact Energy	Recommendation
		representation of actual beneficiaries in this instance as to be meaningless. As the Authority notes, the risk of applying this approach is that it places disproportionately large transmission costs to a relatively small number of parties, thereby necessitating further policy measures to be politically acceptable (e.g. a limit above which the approach would not apply and a different method for allocating excess capacity costs for when that limit is surpassed). We see this as compounding the overall complexity of the regime for no benefit. Under Transpower's "pool and share" approach a stakeholder would be able to approximate with a reasonable degree of accuracy the additional costs to them of anticipatory investments. It is therefore more likely that stakeholders will be motivated to interrogate anticipatory investments. We agree with many of Transpower's other points on this issue, including: • the costs associated with changing fundamentally the way connection charges work are not justified given the level of satisfaction customers have with how they work currently. No submitter on Transpower's *Connection Charges consultation paper* advocated for additional component C (which is being relied on by the Authority in its preferred approach) to be implemented; • the principles in clauses 1(b)(ii) and (iii) of the Guidelines argue for simplicity and certainty in the transition to the new TPM; • any potential efficiency gains of the Authority's approach would be outweighed by the administrative costs of making the change; and additional component C in the Guidelines only applies to "new connection investments" and we therefore question how the Authority can apply this section to brownfield investments as well as greenfield investments. If additional component C were to be limited to "new connection investments" as the Guidelines state then this would create further inefficiencies. As well as introducing an additional layer of complication into transmission charges, this different treatment would discriminate arbitrarily between existing and new customers and could result in inefficient incentives when new customers are deciding where to connect to the grid. This is contrary to the principles in clauses 1I and I of the Guidelines.
Do you have any other feedback on the proposed TPM in relation to connection charges?		None.

TPM Proposal	Contact Energy	Recommendation
Chapter 5: Benefit based charge: allocation		**(Sections 13 – 30 of the Guidelines)**
Do you have any comment on the proposed standard and simple benefit-based allocation methods?	Support	Contact supports the principle that those who benefit from a grid investment should pay it. However, we have increasing concerns with the complexity of the new regime and the inability of stakeholders to know with any certainty what transmission charges will be under a range of circumstances. This uncertainty creates its own inefficiencies and contrasts with electricity prices where long-term PPAs with fixed prices have become the norm for new parties connecting to the grid. In our view, the same level of certainty should equally apply to transmission charges. Our experience has been that potential new load customers have been reluctant to switch to electricity from fossil fuels as they do not have any visibility as to the quantum of transmission charges under the new regime. The concerns around complexity and transparency are particularly relevant to the standard method as the modelled beneficiary regions will differ for each benefit-based investment. This means that stakeholders will not be able to model for themselves their potential transmission charges prior to making an investment decision. Our concerns with the simple method relate to the weighting of beneficiaries between load and generation. As explained below, we consider the proposed 50:50 weighting between load and generation to be relatively arbitrary and non-reflective of the actual beneficiaries of low-value investments.
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?	Change	The Authority is proposing that benefits under the simple method (applied to investments of less than $20 million) be split equally between load and generation customers. This assumes that the net private benefits of load and generation customers are broadly equal to Transpower's modelled electricity flows within and between regions. We consider this to be an oversimplification and are concerned that any determination made now will be very difficult to change later, notwithstanding the requirement to review this determination within five years of the TPM coming into force and assuming at least 10 standard method investments had been made. It is not clear to us that reviewing 10 standard method investments will provide a sound basis to allocate beneficiaries for low value investments under the simple method. The nature of high value investments is different from low value investments, with the beneficiaries of high-value investments determined on a case-by-case basis. The benefits arising from low-value investments are much more generalised and should be allocated on the basis of the Authority's best estimate of net private benefits of accruing to load versus generation.

TPM Proposal	Contact Energy	Recommendation
		We support the alternative proposal of benefits under the simple method being split between generation and load customers on a 25:75% basis. In support of this position we note: • the Authority's Cost Benefit Analysis determined materially higher net benefits ($2.8 billion vs $1.25 billion over 28 years) under a scenario that weighed benefits 25:75% load/generation scenario compared to a 50:50% load/generation scenario; • the Authority undertook an analytical approach to assessing relative benefits to load and generation in its 24 May 2021 letter to Transpower (method 2). The Authority derived the net private benefits of a generator from national accounts data and consumer surplus assuming linear demand. The key insight from this analysis was that consumer benefits are between 2 and 7 times that of generation, with a point estimate of 3.68 times that of generation. We note that Transpower did not offer any critique of this analysis in its *Reasons paper*. • Consumer surplus (i.e. total willingness to pay for consumption less expenditure for that consumption) is the correct way to think of net private benefits for load customers. This approach was not undertaken in "Method 1" which used wholesale demand revenue from reconciliation data as a proxy for net private benefits for load customers. Using wholesale demand revenue will materially understate net private benefits for load customers as their willingness to pay, and hence the consumer surplus, is much higher than actual payments. • We have tested "Method 1" using Transpower's estimates for adjusted operating profit for generators (as a proxy for the net private benefits of generators) and a range of consumer surplus estimates using the ratio of consumer to generator net benefits in Table B.5 of the Authority's 24 May 2021 letter to Transpower. All of the results show an implied generator weighting of much less than 50%, with 21% the base case.

Net private benefits of generators relative to load customers

	2016	2017	2018	2019	2020
Adjusted operating profit for generators ($m)	2,413	2,256	3,253	4,111	2,883
Consumer surplus - price elasticity of -0.8 (CS -0.8)	4,826	4,512	6,506	8,222	5,766
Consumer surplus - price elasticity of -0.4 (CS -0.4)	8,880	8,302	11,971	15,128	10,609
Consumer surplus - price elasticity of -0.2 (CS -0.2	16,891	15,792	22,771	28,777	20,181
Implied generator weighting (with CS -0.8)	33%	33%	33%	33%	33%
Implied generator weighting (with CS -.04) - base case	**21%**	**21%**	**21%**	**21%**	**21%**
Implied generator weighting (with CS -0.2)	13%	13%	13%	13%	13%

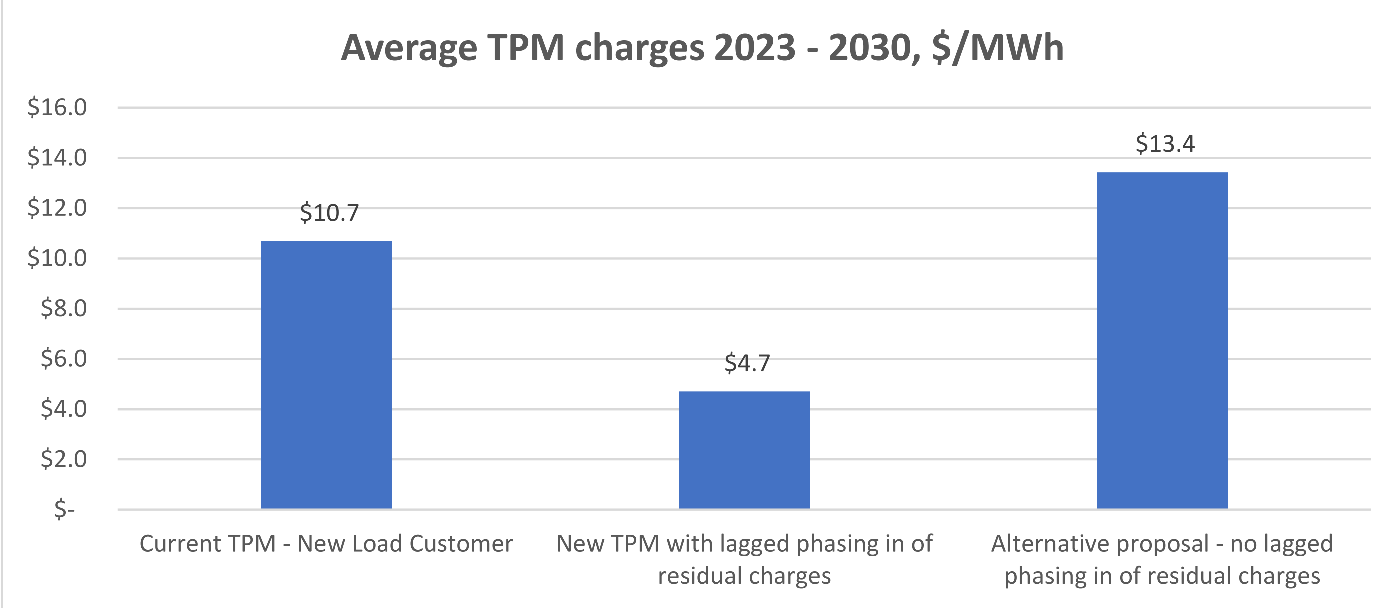
TPM Proposal	Contact Energy	Recommendation
Chapter 6: Benefit-based charges: covered costs		**(Sections 13 – 30 of the Guidelines)**
Do you have any comment on the proposed approach to covered costs, including on whether overhead opex should be recovered through the BBC or residual charge and any evidence to support your view?	Remove	We do not support the introduction of an "attributed opex component" to the definition of "covered costs". We consider this proposal to be inefficient, contrary to the Authority's statutory objective, and a potential impediment to decarbonisation. We also consider it inappropriate to propose making a change of this magnitude at this late stage with no prior consultation. This proposal is linked to the proposal to remove the "injection overhead component" from connection charges. The same arguments made above in reference to the injection overhead component are relevant here. Namely: • the proposal to introduce an attributed opex component to benefit-based charges is inefficient because it will increase costs to generation, resulting in deferred investment as a higher wholesale electricity price will be required to justify making the final investment decision. These costs will ultimately be passed through to consumers. It is far more efficient, as the Authority has consistently argued, that these costs be placed directly on load customers; • the Authority has articulated on multiple occasions its policy intent. That is, Transpower's overhead opex should to a large extent be recovered via the residual charge. To that end, we do not consider that Transpower can call upon clause 2 of the Guidelines given that clause 2 states that Transpower cannot depart from the intent of the Guidelines: Transpower's operational role is to implement the TPM Guidelines and the policy intent of the Authority. It is not to reinterpret the Authority's statutory objective and advance its own policies. We note that Transpower has agreed with this same argument elsewhere (paragraph 240 of the *Reasons paper*) where it argued that it was prevented from using any form of dynamic allocators for benefit-based charges as the Authority's 2020 *Decision* had clearly stated its intent that benefit-based charges should be fixed in nature; • there is general satisfaction with the way connection charges work currently. There is therefore no justification for the removal of the "injection overhead component" of connection charges and its replacement with an "attributed opex component" to benefit-based charges.
Do you have any comment on the proposed approach to covered costs, including on the recovery of opex on	Support	We support the principle of opex on fully depreciated assets being recovered through the residual charge but query the figure of 15% of Transpower assets that are deemed to be fully depreciated. We have not seen any evidence that would support this figure which is a material component in the calculation of the "attributable opex ratio".

TPM Proposal	Contact Energy	Recommendation
fully depreciated assets through the residual charge?		
Drafting issues in the TPM	Change	Clause 54(3) – the word "zone" is bolded but undefined in the table Clause 55(3) – the explanation of the formula should be rewritten to align with the formula. "UE" should be replaced with "CE" to represent "curtailed energy"
Chapter 7: Residual charges		**(Sections 27 – 30 of the Guidelines)**
Do you have any comment on how the proposed TPM implements the residual charge provided for in the Guidelines?	Support	We support the proposed approach to residual charges, being paid by load customers only, in proportion to their gross historic anytime maximum demand, averaged across four financial years starting 2014-2017. These initial allocations are then updated annually, based on changes in customers' lagged four-year rolling average of gross energy usage, with this four-year period commencing the financial year eight years prior.
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?	Support	We support the Authority's approach to dealing with the situation where an embedded generator injects into a distribution network (or other load customer) and the injection passes through into the grid. As the residual charge is intended to be allocated based on customer size (as a proxy for ability to pay), the residual allocator should capture a load customer's final electricity demand. That means it should capture electricity sourced from embedded generation that is consumed by the load customer and not electricity that is reinjected into the grid at that load customer's GXP. Netting off this grid injection as part of the definition of gross load addresses this issue.
Do you have any comment on the proposed approach to application of the residual charge to battery storage to avoid double-counting of load?	Support	We agree with the problem definition and the way the Authority has addressed this issue. We are pleased that the issues raised by Contact in December 2020 have been acknowledged and addressed. Ensuring sufficient data is available for the residual charge to be feasible is an issue we have been grappling with. We are pleased to see that the Authority acknowledges that further Code amendments relating to information disclosure may be appropriate and we would like to see this work progress with urgency once the TPM has been finalised.
Chapter 8: Adjustments		**(Sections 27 – 48 of the Guidelines)**

TPM Proposal	Contact Energy	Recommendation
Do you agree with or have any other feedback on the proposed provisions for adjusting transmission charges?	Generally support	We support • the lagged phasing in of residual charges to new customers; • treating de-ratings in the same manner as customer exits and plant closures. In our view, each of these events should result in the immediate cessation of benefit-based and residual charges as they relate to that asset. They should not result in a reallocation of benefit-based charges to the same customer for benefit-based investments that have been commissioned within the last 10 years. We do not support the continuation of benefit-based charges for benefit-based investments commissioned within the last 10 years in the event of plant closure, plant derating, or embedded generator closure or derating for a transmission customer with multiple assets.
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	Support	We do not support the proposal to allocate benefit-based charges for a new entrant (or an incumbent opening a new plant or substantially increasing its energy use) based on the allocation of charges that an equivalent incumbent would pay in the same year. This is distortionary and will impose additional costs onto an incumbent compared to a new entrant. As the Authority noted in its 2020 *Decision Paper* (para 9.24), this raises similar issues to the first mover disadvantage in the context of the connection charge. By adopting the "whole-of-life" approach to a new entrant, any such disadvantage is alleviated because while the first customer to benefit from a new interconnection investment may initially be subject to higher interconnection charges, customers appearing at a later date will still pay charges that reflect their share of benefits across the investment's whole life.
The Authority welcomes feedback on whether the thresholds for "large" and	Support	The definitions of "large" and "substantial sustained change" are appropriate. Large means a plant that is connected to the grid or has a capacity of at least 10 MW, or the upgrade or derating of a plant's capacity of at least 10 MW compared to the plant's capacity before the upgrade/derating.

TPM Proposal	Contact Energy	Recommendation
"substantial sustained" change in grid use.		A substantial, sustained increase is proposed to be an increase in a large plant's expected annual electricity consumption or generation of at least 25% since the last time the relevant customer's BBI customer allocations for one or more BBIs were calculated, and the increase is sustained, ie, expected to last for at least five years.
The Authority welcomes feedback on whether 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	Support	The reasons for adjusting the benefit-based charge for a large generator or plant apply equally to a distributor. A new GXP and a transformer upgrade are reasonable thresholds to signify a substantial sustained increase in use.
The Authority welcomes feedback on whether the plant disconnection provision should be extended to plant de-rating	Support	Consistent with previous submissions, we think that transmission charges (whether they be benefit-based or residual) should only be payable when a party uses the transmission grid. Transmission charges should not be payable when a customer exits, closes or derates a plant (for that part of the plant that has been derated). We do not agree with clause 33(d) of the Guidelines and clauses 86(6) and 86(7) of the Draft Code that require transmission customers to continue to pay benefit-based charges for benefit-based investments commissioned within the last 10-years. With regard to the Authority's consultation document, we support treating a large de-rating as the same type of event as a plant closure. We differ from the Authority over the proposal that both adjustment events would continue to see transmission charges payable by the transmission customer for those closed/de-rated assets.
The Authority welcomes feedback on whether 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	Support	We support extending the adjustment provisions to include the exit of an embedded party, such that a load customer's residual charge would adjust immediately rather than phase down with a lag following an embedded load party's exit. However, we think that a load customer's residual charges should also adjust immediately in the event that the embedded generators closes but continues drawing electricity from the grid, or derates the plant. This provides consistency of treatment with how we see transmission charges should apply to plant closure or plant deratings.

TPM Proposal	Contact Energy	Recommendation
The Authority welcomes feedback on whether 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	Support	The related entity provisions are only required because the Authority is proposing to reallocate to a transmission customer the transmission charges attributable to a plant that the transmission customer has closed. We think that transmission charges should cease the moment that transmission services are no longer used. If transmission charges were to cease following large plant closure or a large plant derating (for that portion of the plant that has been derated), then there would be no need for these related party provisions.
The Authority welcomes feedback on whether the residual charge for a new entrant and an expanding customer should adjust with a lag and a gradual ramp-up, as proposed.	Strongly support	We strongly support the Authority's proposal that the residual charge for a new entrant customer ramps up gradually with a lag, such that a new entrant entering in year one begins to pay the residual charge in year 5 and pays a full-scale residual charge from year 8. Some of our customers are facing an investment decision to replace process heat coal boiler with an electrode boiler plant. The following chart shows our modelling across a range of customers of the expected transmission charge (excluding connection charges) under the current TPM, the TPM with a lagged phasing in of residual charges, and Transpower's alternative proposal with no lagged phasing in of residual charges.

TPM Proposal	Contact Energy	Recommendation
		 The modelling work has highlighted that transmission charges under the proposed TPM for new process heat load will be materially lower in the early years than Transpower's alternative approach. The following table shows the materiality of transmission costs relative to the fossil fuel alternative. The Authority's proposal would see the benefit-based and residual charges accounting for 9% of the process heat costs from coal (with a carbon cost assumption of $65/tCO_2$). This increases to 27% under the Transpower's alternative.

<table>
<tr><th>TPM Proposal</th><th>Contact Energy</th><th>Recommendation</th></tr>
<tr><td></td><td></td><td>
<table>
<tr><th colspan="3">Transmission costs as a percentage of process heat costs of coal</th></tr>
<tr><th></th><th>Lagged phase in of residual charge</th><th>Transpower's alternative - no lagged phasing in of residual charge</th></tr>
<tr><td>Cost of process heat from Coal at $65/Ton CO2e in $/MWh</td><td>$ 50.0</td><td>$ 50.0</td></tr>
<tr><td>Transmission costs ($/MWh)</td><td>$ 13.4</td><td>$ 4.7</td></tr>
<tr><td>Transmission costs as a percentage of heat costs</td><td>27%</td><td>9%</td></tr>
</table>
Transmission costs at $13.4/MWh will materially impact the economics of the process heat electrification projects we are seeing, potentially putting them at risk. As such, we strongly support lagged application of the residual charge to new load.
Pass through of transmission costs by distributors risks undermining the Authority’s intent
A separate but related issue is how local distribution companies intend to pass through transmission charges to new process heat load. From our discussions with local distributors it is not clear whether transmission charges to new load customers will be passed through on an incremental (i.e. the incremental transmission costs of new load to the network being passed through to the new load customer) or average basis (i.e. the average transmission costs across the network applied to the new load customer). We are concerned that our local network will pass through charges in a manner that is inconsistent with the proposed TPM. We strongly encourage the Electricity Authority to be clear that they expect local networks to reflect the lagged residual charge in the pass through of transmission charges to customers with new process heat load.
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<tr><td>The Authority welcomes feedback on whether the proposed TPM should include a specific provision for the adjustment of the residual charge of a large customer that closes a plant</td><td>Support</td><td>Our response to these questions has been outlined in responses above. We consider that transmission charges should apply for the use of transmission services and cease when a transmission customer exits, a large plant closes, or there has been a large derating of a plant. We do not agree with the existing proposal that benefit-based charges be reallocated to the transmission customer that closes a large plant for a period of 10-years. The same arguments apply for a large derating of a plant, and the closure or large derating of an embedded generator.</td></tr>
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TPM Proposal	Contact Energy	Recommendation
(either to allow its adjustment immediately or in some other way), or should the standard lagged adjustment of the residual charge apply? If the former, should the provision be extended to deratings? If the latter, should it apply to embedded parties and should there be a related entity provision?		
The Authority welcomes feedback on whether a new related entity provision should be provided for the residual charge.	Support	As noted above, the related entity provisions are only required because the Authority is proposing to reallocate to a transmission customer the transmission charges attributable benefit-based investments commissioned within the last 10 years. We think that transmission charges should cease the moment that transmission services are no longer used. If transmission charges were to cease following large plant closure or a large plant derating (for that portion of the plant that has been derated), then there would be no need for these related party provisions.
Chapter 9: Prudent discount policy		**(Sections 45 – 48 of the Guidelines)**
Application of a prudent discount policy (PDP)	Support	We support the inclusion of a stand-alone cost prudent discount and see this as a welcome improvement from the status quo. Given the novelty of the addition, the preparation of a prudent discount practice manual is welcomed.
The Authority welcomes comment on any aspect of the proposal, including whether the proposed TPM adequately prescribes the fundamental aspects of the PDP	Support	No comment.

TPM Proposal	Contact Energy	Recommendation
Should Transpower have to prepare a prudent discount manual, and if so when, and should it be binding on Transpower.	Support	We support the publication of a prudent discount manual and consider this should be produced at the same time as the Assumptions Book that Transpower is required to publish and which sets out the detailed methodologies that Transpower will apply for allocating and adjusting benefit-based charges. To provide certainty to all stakeholders, we think this prudent discount manual should be binding on Transpower.
Should 15 years be the default maximum period with a longer term possible on proof?	Support	15 years seems like a reasonable default maximum period.
Should prudent discounts be funded via the residual charge and as appropriate the benefit-based charge?	Support	We support the proposal that prudent discounts be funded by: • customers that are beneficiaries of the investments for which the recipient of the prudent discount pays benefit-based charges, and • load customers paying the residual charge.
Should customers be able to terminate a prudent discount agreement before the end date of the agreement?	Support	Customers should be able to terminate a prudent discount agreement before the end date of the agreement should they wish to do so.
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	Support	This issue has been well traversed and we are comfortable with where the Authority and Transpower have landed on this issue.

TPM Proposal	Contact Energy	Recommendation
effective tools to manage the power system quickly and efficiently?		
Chapter 11: kvar charge		
Do you have any comment on the proposal not to include a kVAr charge in the proposed TPM?	Support	No comment.