Transmission pricing methodology amendments: a level playing field for emerging technologies

Decision paper

26 November 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (Authority) is committed to ensuring that we continue to improve the functionality of the transmission pricing methodology (TPM), where necessary, to better encourage efficient investment and use of the grid. Energy storage and other emerging technologies are increasingly used in the grid for a range of purposes including firming renewable generation and indirectly to foster energy resilience at the regional level. We want the TPM to enable the efficient implementation of such emerging technologies and to ensure investment is directed into the right places at the right time.

The Authority has decided to make two amendments to the TPM, to ensure that:

1. **connection charges** for shared connection assets are allocated in a more proportionate way where a customer both injects and offtakes from the grid
2. the effect on **residual charges** of increased consumption – for new customers and for changes in consumption – is more consistent across customers.

We consulted on these proposals in August 2024 and received 12 submissions in response.

Connection charges for shared connection assets

This amendment will ensure connection charges for shared connection assets are based on only the maximum capacity used – for all customers. This will help to level the playing field for battery energy storage systems (BESS) and similar technologies compared to other customers, help to improve security of supply and promote more efficient investment, ensuring future electricity prices for consumers will be lower than they would otherwise be.

The proposed amendment received widespread support from the majority of submissions. We have decided to implement the proposal as outlined in the consultation paper.[1]

Residual charge annual adjustment

This amendment will ensure changes in consumption have a more consistent effect on residual charges for customers with different load profiles. It will correct some misaligned incentives and promote more efficient investment, including in grid-scale BESS and other emerging technologies. This will support more efficient electrification of the economy and relatively lower electricity prices for consumers.

There is industry support for our proposals, however some have suggested resolving the identified issue using alternative approaches that would mean more extensive changes to the allocation of the residual charge. Having considered these alternative suggestions, the Authority still considers its proposed approach to be the least distortionary option. Some submitters have raised concerns over differences in charges between new customers and some existing customers. We acknowledge these concerns, however the Authority considers that these possible effects are likely to be outweighed by the expected benefits of our new approach, which is focused on ensuring a level playing field for future investments, including in emerging technologies.

We have decided to implement the proposal as outlined in the consultation paper. Both of these amendments will come into force in April 2026.

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[1] Refer to: Transmission pricing methodology amendments: a level playing field for emerging technologies (ea.govt.nz)

Contents

1. Allocation of connection charges at shared connection assets

Our decision

1.1. The Authority has decided to adopt the Code amendment on allocation of connection charges that was proposed in August 2024.

1.2. Connection charges for shared connection assets will be allocated based on the greater of anytime maximum demand for consumption (AMDC) and anytime maximum injection capacity (AMIC) for each customer.

1.3. This amendment to the TPM will apply from 1 April 2026.

The issue

1.4. A potential issue with the connection charge adjustment clause was identified when considering the integration of a battery energy storage system (BESS) into the grid at an existing connection location.

1.5. The integration of a large-scale connection (≥10MW) triggers a connection charge adjustment under the TPM. For connection charge adjustments, Transpower must determine whether the connecting customer will serve as an offtake or injection customer and, accordingly, estimate the customer's AMDC or AMIC, depending on Transpower's determination.

1.6. Under the existing TPM:

(a) during the initial two-year period, Transpower must estimate the connection charge allocation at a shared connection asset using either AMDC or AMIC

(b) after this period, the customer allocation is calculated by combining the customer's anytime maximum demand and injection (AMDIC).

1.7. Most transmission customers will primarily be either load or injection, which means their connection charges will remain largely unchanged after the initial period.

1.8. For technologies like BESS, the connection charge allocation during the initial period will be similar to that of an equivalent-sized load customer or generator. However, after this period, the BESS or a similar technology could be charged double the connection charge of an equivalent-sized load customer or generator. This is because a BESS both injects into and offtakes from the grid, with its allocation at the shared connection asset being based on the sum of both its anytime maximum demand and injection (AMDIC).

What we proposed

1.9. The Authority proposed a change to clause 32 of the TPM such that the allocation of connection charges for shared connection assets after the two-year period would be based on the greater of demand (AMDC) and injection (AMIC) for each customer.

1.10. The Authority proposed the change would apply from April 2026 to ensure Transpower would have sufficient time to make necessary changes and engage with its customers. In our view, informed by Transpower’s operational feedback, a change for pricing year 2025/26 is unlikely to be possible.

Submitter views and our assessment

1.11. We received largely positive feedback from submitters on the proposed amendment for the allocation of connection charges for shared connection assets. Ten of the 12 submissions received were in favour of the amendment, emphasising support for changes that help to level the playing field for new technologies. Lodestone Energy stated:

> *Lodestone welcomes the proposed amendment for connection charges. We also believe it will help ensure a level playing field for new technologies like BESS, which would otherwise be disadvantaged under the current TPM. Lodestone notes that many utility-scale solar projects are designed and built to be battery-ready. The proposed amendment will further facilitate bringing these projects to fruition.*

1.12. New Zealand Steel raised some concerns about the impact that large connections at shared connection assets will have on existing connections. They stated that:

> *BESS is already under construction in NZ and will be significant size even at the larger GXPs involved. In many situations BESS will likely dwarf existing connections. Upgrading of GXPs will also likely be a norm. The paper does not mention these factors and how these investments can be accommodated within the TPM first-mover provisions and what impacts this may have on existing Customers.*

1.13. We have considered NZ Steel's concerns. The Authority's view is that our new approach would mean costs are appropriately allocated between connecting parties – regardless of whether the GXP is upgraded or whether the BESS is larger than existing connections. The Authority considers that the reasons for its proposal continue to apply in the circumstances noted by NZ Steel. Under the new allocation approach, both existing and new customers will pay a more appropriate share of the costs at shared connection locations. This will promote more efficient investment. We would also note that some scenarios do not fall within scope of the connection charges allocation.[2]

1.14. As noted by NZ Steel, there are other mechanisms in the TPM, such as the anticipatory connection asset mechanism (cl 26(3) of the TPM) designed to mitigate first mover disadvantage by allowing for some costs to be paid by a wider group of customers.[3] We do not anticipate any difficulties accommodating our new approach (which results in a more appropriate allocation of those costs that are borne by connecting parties) with these other mechanisms.

1.15. NZ Steel has also suggested that given the small number of Transpower Customer connection points that will have a shared connection asset and the scale of customer size imbalances potentially involved, a case-by-case approach

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[2] We note that for new connections, a Transpower Works Agreement (TWA) with the connecting customer can fund the cost of the new connection investment. A Transpower Works Agreement is used where Transpower is requested to build and commission new grid-connected assets for a customer project, for example, a new connection to the grid or an upgrade of an existing connection to the grid. The costs to be paid under a TWA are the actual delivery costs, plus interest during construction and (where applicable) financing costs. Where a customer does not wish to pay for the new connection investment in full as it is developed, Transpower may offer financing arrangements as part of the TWA.

[3] For more information see Transpower's guide: TPM information sheet connection charges FMD Type 2 v1.pdf (transpower.co.nz)

determined by Transpower would be more appropriate. It does not agree with a one-size-fits-all Code approach that could potentially create further anomalies within the TPM.

1.16. While it may be the case at present that there is only a small number of connections impacted by this issue, the Authority is interested in future-proofing the TPM. If new technologies like BESS are increasingly adopted, the number of shared connections can be expected to increase so that the level of inefficiency would grow if the current TPM were to continue to apply. Additionally, having differing approaches to the calculation would likely cause more complication and be an administrative burden on Transpower. Therefore, we have decided to amend the allocation calculation to apply to all shared connection assets.

1.17. The Authority considers the proposed approach to allocating connection charges for shared connection assets is the best way forward for levelling the playing field for emerging technologies and ensures that the TPM does not inefficiently discourage investment in BESS and other similar technologies. The Authority considers that this change is consistent with the intent of the 2020 TPM Guidelines.

2. Allocation of residual charges

Our decision

2.1. The Authority has decided to adopt the Code amendment on allocation of residual charges that was proposed in August 2024.

2.2. A uniform rate for conversion from MWh to MW will be applied to the residual charge allocation where changes in energy consumption are above the customer's baseline level of consumption.

2.3. Additionally, a new customer's initial residual charge will no longer be based on its own estimated capacity. Instead, it will be determined based on its estimated energy consumption and converted to MW using the uniform conversion rate, which is based on the average load factor of existing customers.

2.4. This amendment to the TPM will apply from 1 April 2026.

The issue

2.5. Under the current TPM, the incremental cost of increased energy consumption (in $/MWh) under the residual charge will vary based on the relationship between a customer's baseline capacity and baseline gross energy consumption. This ratio is also commonly known as a customer's 'load factor'.

2.6. For the purposes of residual charge allocation, increases in consumption for peaky customers (with low baseline load factors) are effectively converted to MW at a higher rate compared to flat demand customers (with high baseline load factors). This means a low load factor customer that increases its energy consumption will experience a larger increase in its residual charge allocation than a high load factor customer that increases its energy consumption by the same amount.

2.7. Furthermore, a new customer's residual charge depends on the anytime maximum demand (AMD) of the new load it is connecting, whereas if the same new load is added by an existing customer, its increase in residual charge will also depend on the load factor of its (pre-existing) baseline load.

2.8. Essentially, the incremental residual charge (in $/MWh) for additional energy consumption will vary depending on the type of customer that increases consumption.

What we proposed

2.9. To address the issue with residual charge allocation discussed above, we proposed to amend the Code to change the way the residual charge is allocated in respect of new connections and changes in consumption so the effect of incremental consumption on the allocation is more consistent across customers.

2.10. First, we proposed that for changes in energy consumption above the customer's baseline level of consumption (ATGEbaseline), such changes would be converted to MW at a uniform rate for residual charge allocation purposes. This would mean all existing customers pay the same incremental increase in residual charge for a given amount of additional gross energy consumption.

2.11. We did not propose to change the approach where a customer decreases its energy consumption below its baseline level of consumption (ATGEbaseline). So long as a customer's consumption is below its baseline level, changes in consumption would continue to be converted to MW in the way set out by the existing TPM, ie, based on the customer's individual load factor.

2.12. Second, we proposed to change how the initial residual charge for a new customer is set. Under our proposal, a new customer's initial residual charge will no longer be based on its own estimated capacity. Instead, it will be determined based on its estimated energy consumption and converted to MW using the uniform conversion rate based on the average load factor of existing customers.

Submitter views and our assessment

2.13. We received submissions from Mercury, Meridian, Genesis, Lodestone and Nova supporting the proposed changes to the residual charge.

2.14. Mercury stated:

> *The Authority's proposed amendment to the RC charge is forward-looking, in so far as it is for customer adding new load or increasing energy consumption. It is not intended to change the approach to RC allocation for changes in energy consumption below baseline consumption levels. Nonetheless, Mercury agrees with the intent of proposed amendments to the residual charge annual adjustment, particularly to remove inequitable barriers for different parties potentially investing in BESS.*

2.15. Additionally, Genesis supports this amendment, stating:

> *The existing methodology to calculating Residual Charges distorts incentives among Transpower customers with respect to development of new technology projects, including BESS. As noted in the Paper, this has potential to reduce efficiency and competition (paragraphs 3.25-3.29), to the long-term detriment of consumers. Moreover, residual charges are not designed to influence investment decisions. The proposed amendment will mitigate these issues.*

2.16. Several submitters highlighted some concerns they had with the proposed amendment for the allocation of the residual charge, as discussed below.

Allocator used to calculate residual charge

2.17. Some submitters have suggested that a lack of consistency between the baseline allocator and the allocator used for ongoing adjustments (due to changes in gross energy) are the source of the issue and the Authority should consider an alternative approach to allocating residual charges that uses the same allocator for both the initial allocation and ongoing adjustments.

2.18. For example, NewPower Energy does not agree with the current allocators used for the residual charge and states:

> *The easiest way to address the problem that has been identified is to change the Residual Charge methodology to be based only on gross energy consumption (and remove any impact of capacity and the capacity factor). This will create a charge that is equal across all types of load customers, existing and new, and be*

equitable whether or not the customer is experiencing an increase in energy consumption.

2.19. The Authority does not agree that an approach based solely on gross energy consumption would be appropriate. As discussed in the August consultation paper, the Authority has earlier considered using energy consumption (MWh) for the initial allocation of the residual charge, but preferred using a historical measure of capacity (AMD) for this purpose. The Authority considered capacity to be a suitable proxy for size and ability to pay, and considered that – for initial allocation of the residual charge – it was preferable to energy consumption, which was "judged likely to have a material adverse impact on some industrial load customers, which could potentially lead to inefficient disconnection". An allocator based on AMD would be less likely (than a MWh allocator) to cause the disconnection of a large industrial consumer (as such consumers tend to have relatively flat load profiles). As such, the Authority selected a historical measure of AMD as the allocator for the initial residual charge. The Authority's view is that these considerations still apply.

2.20. Transpower, on the other hand, agreed that the status quo is disproportionate but suggested an alternative approach to the annual residual charge allocation would be to base all existing and new customer's annual allocations on a lagged four-year gross AMD. It submitted:

We consider gross AMD would be very difficult to manipulate with intent to shift costs to other parties because:

(a) the "anytime" aspect would require attention to managing one's own rates of change of energy use across all consuming periods

(b) the "gross" aspect would require understanding others' co-incident production behaviours across all consuming periods (at the connection location / point of connection)

(c) co-ordination would be needed for both consumption and production to be minimised at the same time; and

(d) a customer's resultant allocation depends on all others' consumption behaviours across the entire grid and production behaviours in distribution networks.

2.21. The Authority does not agree that an approach based solely on AMD would be appropriate. We considered updating the residual charge allocation based on changes to a customer's AMD. However, updating a customer's allocation based on its change in gross AMD could be distortionary, even with a lag, as "AMD is a measure of peak demand that a customer could adjust at low-cost relative to other measures (such as total usage). AMD is also easier for a customer to predict and control."[4] The Authority considered that *historical* AMD was an appropriate allocator for the initial allocation of the residual charge (noting that a historical measure cannot be altered and so would not be distortionary) but that AMD would not be appropriate for use as an ongoing allocator for adjustments.

2.22. The Authority continues to consider that use of AMD as an ongoing allocator for adjustments would be distortionary, notwithstanding Transpower's views as to the

4 Refer to: https://www.ea.govt.nz/documents/1895/26354TPM-supplementary-consultation-Feb-2020.pdf

difficulty of manipulation. We note that under the old (pre-2023) TPM, the main allocator, regional coincident peak demand (RCPD) was also, in theory, difficult to manipulate and predict, as it relied on other parties' demand in the region and estimating in advance the 100 top demand periods. However, parties found a way to do so – RCPD caused much distortion. This reinforces the Authority's view that it is inadvisable to establish a system that creates perverse incentives, as parties will find a way around practical obstacles if it is in their financial interest to do so. The preferable approach is to put in place an allocator for ongoing adjustment (based on lagged MWh) that does not create strong incentives for parties to avoid the charge.

2.23. Transpower also states that:

> *A MW allocator for costs passed through by distributors to consumers would also support the Authority's intent to enable time-of-use pricing for distributors and retain the Guideline policy that anytime maximum demand is a proxy for customers' relative size and ability to pay.*

2.24. The Authority does not agree that a MW allocator for ongoing adjustments to the residual would support the Authority's intent to enable time-of-use pricing for distributors. Time-of-use pricing for distributors is intended to signal distribution network costs that can be avoided (eg by load-shifting). The residual charge is largely intended for the recovery of costs that cannot be avoided (such as some historical grid investment costs) and is not intended to send a usage signal at all.[5] We would note that MWh (and not only MW) can be a proxy for customer size.

2.25. Entrust suggests that the proposed amendment is adding complexity to an already complex charge and suggests exploring whether alternative methodologies would be more durable. Additionally, Entrust submits that the Authority's decision to ban use of anytime maximum demand for distribution pricing puts into question its efficacy for transmission pricing.

2.26. The Authority considers that its new approach does not lead to excessive complexity. A uniform conversion rate could be considered less complex than multiple conversion rates that differ for every customer. Further, the Authority disagrees with Entrust's point regarding distribution pricing versus transmission pricing. The Authority *discourages* the *ongoing* allocation of distribution charges using AMD, as this would signal substantially more than the economic cost of use and might discourage consumption at times when there is no network congestion.[6] By contrast, the TPM uses a *historical* measure of AMD to allocate *initial* residual charges. *Historical* AMD cannot be altered and so this allocation method does not affect ongoing consumption. Therefore, there is no inconsistency: the Authority discourages the *ongoing* allocation of transmission charges using AMD for

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5 This is in contrast to benefit-based charges and time-of-use distribution charges, which are intended to send price signals.

6 A core part of the TPM reform was removing the Regional Coincident Peak Demand (RCPD) charge. The RCPD charge signalled substantially more than the economic cost of use, and discouraged consumption at times when consumers valued it the most, and often needlessly – on networks that had no congestion issues. The Authority considered that a similar issue might be occurring on distribution networks through charges based on an individual customer's own AMD to recover fixed charges at times when there is no congestion on the network. Refer to: https://www.ea.govt.nz/documents/2631/Letter-to-distributors-re-pricing-September-2022_w2bVZa1.pdf

essentially the same reason as it discourages the *ongoing* allocation of distribution charges using AMD.

2.27. New Zealand Steel made several points regarding the allocator used for the residual charge. They consider that the use of AMD as an allocator is contrary to the objective of efficiency and the proposed adjustment by four-year rolling average of gross annual energy usage does nothing to improve the issue. They consider that AMD applied at the GXP level is inappropriate and inequitable and the use of gross rather than net, demand or throughput is inappropriate when there is cogeneration such as at New Zealand Steel.

2.28. In response to New Zealand Steel's points made about the AMD applied at GXP level being inappropriate, we note that the Authority considered the level at which AMD should be applied in the *Transmission pricing methodology 2020 Guidelines and process for development of a proposed TPM (Guidelines)* decision paper.[7] There were both pros and cons for applying it at the GXP level but the Authority ultimately decided on this approach for the reasons outlined in the Guidelines paper in paragraph A.47 to A.52. These reasons continue to hold.

2.29. In response to New Zealand Steel's points made about the gross vs net approach to measuring annual energy usage for residual charge allocation purposes, the Authority outlined the rationale for the gross approach in the *Transmission Pricing Methodology 2022* decision paper. The residual charge is intended to avoid creating incentives for parties to change their use of or connection to the grid to avoid charges. If the residual charge allocator was based on load net of embedded generation, it would encourage a transmission customer to favour such generation over electricity from the grid. The gross approach avoids creating incentives to unnecessarily invest in embedded generation. If a customer decides to invest in co-generation, this will potentially be reflected in lower benefits from any new grid investment, and so a lower benefit-based charge. It also results in the customer having reduced wholesale electricity costs due to lower purchases of electricity from the grid. If investment in co-generation had the effect of reducing a customer's residual charge allocator, this would provide it with an unwarranted financial advantage over other forms of electricity supply, with the risk that co-generation would be undertaken in part based on an objective of reducing transmission residual charges. The gross approach was tested during judicial review in April 2023.[8] It was found that the reasons for this approach were rational and consistent with the Authority's objectives.

2.30. Tesla submitted that storage should be exempt from the anytime gross demand (AMDR) charge for load customers, given storage assets are not 'end-use consumers' and therefore should not be considered as load in a traditional sense.

2.31. In response to Tesla's point, we note that a battery only attracts a residual charge based on its final consumption of energy (the battery's losses) rather than its total energy when charging and discharging. This approach effectively recognises that storage assets are not 'end-use consumers' and therefore should not be considered as load in a traditional sense. The decision paper: Transmission Pricing

7 Refer to: https://www.ea.govt.nz/documents/1887/26851TPM-Decision-paper-10-June-2020.pdf

8 Refer to: https://www.nzlii.org/cgi-bin/sinodisp/nz/cases/NZCA/2023/275.html

Methodology 2022 discusses submitters' views on this topic and the reasons why this decision was made.[9]

Application of residual charge to new customers

2.32. NewPower Energy and Infratec do not agree with the changes to the residual charge applying to new customers and not to existing customers with a decrease or no change in load. They consider that this inconsistency fails to create a level playing field for existing transmission customers as they argue that similar technologies will be charged at higher rates if they are existing customers compared to new customers who will be charged using the uniform conversion factor. Similarly, Entrust submitted that having two different transmission customers with identical grid use with different charges has adverse implications for competition and investment.

2.33. NewPower raised a concern about competition between generators, stating:

For example, if we have interpreted the data correctly, Table 2 shows a Generator pays $1,394,813 under the Status Quo. The Status Quo continues to apply if this Generator does not experience an increase in gross energy consumption. So this existing Generator pays $1,394,813 for the use of the same transmission assets while a NEW Generator pays $110,778 under the Authority's proposal.

2.34. However, this is a misunderstanding of the data presented in our consultation paper: Table 2 does not, in fact, compare charges paid by existing generators and new generators. Table 2 of the consultation paper illustrates the median incremental annual residual charge associated with a 10,000 MWh per year increase in energy consumption.[10] This table reports on the impact of consuming an additional 10,000 MWh annually, under the status quo versus under the proposal. The table aims to highlight current discrepancies in charges when a 100 MW Battery Energy Storage System (BESS) is added by a distributor, direct connect, and generator. It demonstrates how applying a uniform conversion factor ensures a level playing field for all parties when additional capacity is introduced.

2.35. With regard to applying the uniform rate to new customers, we acknowledged in our consultation paper that this change may have effects on competition between transmission customers who choose to compete using current technologies (including sunk investments) and new customers entering a market. For example, it could affect competition between an existing industrial customer (which is not expanding) and a hypothetical new industrial customer competing in downstream world markets for some industrial product.

2.36. This could be avoided by revisiting (and applying the uniform rate to) the initial charge allocation for existing customers. However, the Authority is not minded to revisit the initial residual charge allocation for existing customers. That could lead to possible material adverse impact on some industrial load customers, which could potentially lead to inefficient disconnection.

2.37. We acknowledge the potential effect on competition between an existing, non-expanding industrial customer and a hypothetical new industrial customer; however,

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9 Refer to: https://www.ea.govt.nz/documents/1809/2022-TPM-Decision-paper1358263.1.pdf

10 Refer to table 2: https://www.ea.govt.nz/documents/5369/Consultation_paper_-_Emerging_technologies_in_the_TPM.pdf

the Authority's view is that the more important competition problem to address is a potential discrepancy between a new entrant and an equivalent expanding incumbent. Addressing this (which our decision does) is more important because:

(a) it is the potential new entrant and the potential expanding incumbent that are facing immediate resource decisions

(b) if such a discrepancy between the potential new entrant and the potential expanding incumbent was created, as explained in our consultation paper, it might create inefficient incentives for customers to alter their connection or business arrangements in order to reduce their residual charges.

2.38. The new approach will have significant advantages for the efficiency of new investments. In particular, the Authority considers that its new approach will avoid perverse incentives and inefficient investment (which could lead to unnecessary additional costs), as the new approach will ensure a level playing field:

(a) between one existing transmission customer and another that are choosing to compete with new investments (including in emerging technology)

(b) between existing and new transmission customers choosing to compete with new investments (including in emerging technology).

2.39. Contact Energy supports the proposed solution on the basis that it addresses the immediate challenges regarding investment in certain technologies such as BESS. However, Contact submits that the proposed amendment may create distortions:

> *The residual charge for energy consumption is open to manipulation, and the incentives to manipulate will often not be related to underlying system costs. For example, because generators have a low load factor, any reduction in energy consumed will have a disproportionate impact on our residual charges. This may impact on how certain plant are run, and incentives for off-grid electricity supply, which are likely inefficient to the system overall. It may also encourage complex financial structures to take advantage of the provisions for new customers.*

2.40. Regarding Contact's point that the proposed amendment could encourage complex financial structures to take advantage of the provisions for new customers, new load for existing customers would be treated the same under the proposal as the load of new customers, which should limit the incentive for existing customers to take advantage of the provisions for new customers. However, we will be alert to the possibility for manipulation through monitoring existing businesses and any large changes in load. More generally, the Authority recognises there is no perfect allocator for residual charges, as it is impossible to eliminate all effects of the charge on a customer's decision-making. We would note that such issues will decline in magnitude with time, as the amount of grid costs recovered through the residual charge will decline in relative terms over time (due to depreciation of historical grid assets). That said, the Authority considers that its new approach to residual allocation will promote competition,[11] as it will level the playing field for batteries to compete against other generation, promote more efficient investment and better promote the long-term benefit of consumers.

[11] The competition limb of the Authority's main statutory objective is to promote competition in the electricity industry. This means competition in the markets for electricity and electricity-related services.

2.41. The Authority considers that, while this change to residual charge adjustments differs in its detail from the particular requirements of the 2020 TPM Guidelines, it is nevertheless consistent with them by virtue of clause 2 of the Guidelines as the change is consistent with the intent of the Guidelines and it better meets the Authority’s (main) statutory objective.

3. Other points raised by submitters

3.1. Other points were raised about the changes to the TPM in general and regarding the implications of the proposed amendments.

3.2. New Zealand Steel has expressed concerns regarding the durability of the TPM, believing that the Authority has not fully considered the broader implications of the amendments. They argue that modifying the Code without a more comprehensive review undermines the TPM's long-term durability. MEUG shares NZ Steel's view, asserting that these policy changes pose a threat to the durability of the TPM. They view the changes as significant and are particularly worried about the uncertainties that may arise from addressing new technologies and grid arrangements so soon after the TPM's implementation.

3.3. In response to this concern, we note that the Authority consulted in February 2024 on a proposal for the Authority to have the ability to make policy-related amendments to the TPM.[12] We received only one submission in response to this consultation, from Transpower, which raised concerns about the implications for the guidelines with making this change. The Authority incorporated changes based on this submission in our decision paper. Parties were given the opportunity to raise concerns and as a result of receiving no other submissions that highlighted any potential issues, we proceeded with the amendment to the Code that adds a provision to clause 12.94A of the Code that makes it clear that the Authority can amend the TPM under section 38 of the Act if it complies with section 39(1) of the Act.

3.4. In any case, we do not agree that these policy changes pose a threat to the durability of the TPM. When using this power the Authority makes amendments to the Code only where the benefits outweigh the costs. This should provide some reassurance that any proposed changes that may impose significant costs will not occur unless there is a very good reason for them. In this case, by eliminating clearly identified problems and distortions, the changes to charge allocation will improve the TPM's durability.

3.5. New Zealand Steel seeks clarification on whether the Authority is open to considering well-supported submissions addressing other issues within the TPM, which it submits are causing greater inefficiencies than those mentioned in the current paper.

3.6. Regarding opening the TPM to further changes, the Authority has the ability to amend the TPM in accordance with clause 12.94A of the Code. Since commencement of the TPM in April 2023, the Authority has received a number of proposed technical changes from Transpower including errors in formulae and further clarification of clauses which Transpower has identified as being unclear through its implementation of the new TPM. The Authority is open to considering amending the TPM where parties have specific suggestions on how to address other such unintended issues that have been identified.[13]

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12 Refer to: Further clarification for amending the TPM

13 See consultation and decision papers for amendments to correct issues in the TPM: Transmission pricing methodology | Our projects | Electricity Authority (ea.govt.nz)

3.7. Additionally, New Zealand Steel is concerned that BESS charges were specifically addressed in the later stages of the TPM development process and requests that the Authority clarify what has changed to now justify a change to the allocation of charges to BESS. MEUG also points out that BESS was a known technology during the TPM's development and was a topic of consultation in the final stages. It submitted that these amendments are only being pursued now, despite no significant changes in BESS deployment, aside from the initiation of certain projects.

3.8. Regarding New Zealand Steel and MEUG’s concerns in this regard, the approach to charge allocation for shared connection assets was a pre-existing rule in the TPM that predates the Authority’s transmission pricing review. When determining the new TPM Guidelines in 2020, the Authority considered the approach for connection charges should be largely unchanged, as it was considered largely consistent with efficient charging principles. The 2020 TPM Guidelines were largely based on the 2006 Guidelines in respect of connection charges. The issue of charge allocation for shared connection assets that has been considered in this consultation was not specifically raised or considered during the 2019 – 2022 consultation periods. However, while the old approach for shared connection assets worked well in the past, it now appears to be no longer fit for purpose, now that newer technologies such as BESS are increasingly used in New Zealand.

3.9. Additionally, although newer technologies such as BESS were considered in the context of the allocation of the residual charge, the residual charge allocation issue identified in this consultation is not a BESS-specific issue; it applies to all load. As stated in our consultation paper, although this issue was brought to our attention in 2021, detailed evidence of the issue was not available at the time, and the Authority was not convinced that the issue was material. Having considered the issue again, the Authority now considers that the issue creates a material distortion and considers that it should be addressed.

3.10. While Mercury supports the intent behind the proposed changes, they argue that the TPM is excessively complex and demands a high level of specialised expertise to interpret and simplify its details. Consequently, Mercury believes that modifying such a complicated system carries a significant risk of unintended consequences.

3.11. In response to Mercury’s point, we note that there are always risks of unintended consequences when amending any part of the Code. Section 39 of the Act ensures that any proposed changes must be consulted on, which is part of the process for identifying any unintended consequences before a final decision is made.

3.12. New Zealand Steel has made a number of other points that are detailed in its submission. We have considered the points raised and do not consider that any of these arguments provide reasons not to proceed with the Code changes.