Transmission pricing methodology amendments 2026

Consultation paper

29/06/2026

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (Authority) is seeking feedback on proposed amendments to the Transmission Pricing Methodology (TPM). These changes aim to ensure that transmission pricing supports the efficient operation of the electricity industry, including confidence for investment, for the long-term benefit of consumers.

Transmission pricing makes up around 8% of consumers' electricity bills and plays an important role in supporting efficient investment in the electricity system. Transmission pricing influences how the transmission network is used and developed. Getting price settings right helps ensure electricity is reliable and at the lowest long-term cost, with assets built to the right size, in the right location and at the right time.

The TPM sets how the costs of the transmission grid are shared between electricity users. It is based on two core principles:

- charges broadly reflect the benefits customers receive from transmission investments
- charges minimise distortions and avoid shifting costs between customers where there is no broader benefit to consumers from doing so.

This framework remains sound. However, since the TPM's implementation in 2023, the Authority and Transpower have identified some aspects that are not working as intended and where refinements would improve efficiency and workability. These issues have been identified through our ongoing monitoring, stakeholder feedback, Transpower's experience administering the TPM, and Transpower's TPM operational review.

Getting implementation right – proposed amendments

We propose a set of seven amendments, which would be relatively quick to implement and would:

- better align transmission charges with benefits
- reduce volatility and uncertainty in charges
- lower administrative and compliance costs.

Proposals 1-3 were identified by the Authority and proposals 4-7 were requested by Transpower from Workstream 1 of its TPM operational review[1] (although the Authority is proposing some refinements to Transpower's version of proposal 4 on batching adjustments).

We believe these seven amendments will address known implementation issues and improve how the TPM operates, in keeping with its core design. They will better align charges with benefits, strengthen investment signals, reduce unnecessary complexity, and support a stable and predictable framework.

These changes sit alongside our wider network pricing reform programme, including distribution and distributed generation pricing principles, so the overall framework sends coherent and durable network use and investment signals across the system.

The proposed amendments are as follows:

Changes to better implement the TPM

1. *Simple method for battery storage:* refine the simple method benefit-based allocation mechanism by exempting battery storage from the demand factor that applies to offtake

[1] For details on Transpower's TPM operational review, including stakeholder engagement, Code Amendment Requests and supporting documents, see https://www.transpower.co.nz/tpm-operational-review

→ ensures battery storage is not charged disproportionately compared to other supply technologies, supporting more efficient investment and lowering system costs for consumers.

2. *Anticipatory capacity for connection assets:* apply the standard method (instead of the simple method) to allocate the benefit-based component of the capital costs of anticipatory connection capacity investments

   → improves allocation of charges to expected beneficiaries and strengthens incentives to scrutinise investment in anticipatory transmission assets or transmission alternatives.

Technical refinements

3. *WACC alignment:* remove the two-year lag between when a new weighted average cost of capital (WACC) first applies in a Regulatory Control Period and when it is applied to benefit-based charges

   → improves the efficiency of charges and reduces complexity for customers.

Changes to reduce complexity and volatility

4. *Batching adjustments:* process all benefit-based charge adjustment events in one annual batch

   → reduces complexity, volatility and uncertainty for customers and lowers administrative costs for Transpower.

5. *Remove SSI adjustment:* remove the substantial sustained increase (SSI) adjustment event

   → provides certainty for customers and reduces administrative and compliance costs for Transpower.

6. *Simple method period extension:* extend the first simple method period, and use of existing allocators, by up to two years (currently ends 31 March 2028)

   → allows improvements to the simple method to flow through to customers more quickly, and reduces the burden on customers and Transpower of multiple updates in quick succession.

   (We will only consider this extension if Transpower can demonstrate that updated allocators will be in place by the 2030/31 pricing year.)

Drafting refinements

7. *Make technical amendments to drafting:* to improve clarity and remove redundant provisions.

Next steps

We welcome submissions to network.pricing@ea.govt.nz by:

- **7 August 2026** for proposal 2 on anticipatory capacity for connection assets
- **24 July 2026** for the other six proposals.

We expect to make a decision on six of the seven proposals in November 2026, allowing Transpower to incorporate any approved changes into its 2027/28 prices. We plan to decide on proposal for anticipatory capacity in early 2027, as we expect more substantive submissions and will need more time for analysis.

Transpower will continue its operational review of the TPM, focusing on potential improvements to the simple and standard methods for allocating benefit-based charges. Improvements to allocation methods have the potential for bigger gains – aligning charges to beneficiaries is central to the

TPM – but are likely to be more complex and take more time than the amendments proposed in this paper.

Over the next couple of years, we will work closely with Transpower and engage with stakeholders as Transpower develops Code change proposals for the Authority to consider. This work will support more efficient transmission pricing that improves outcomes for New Zealanders.

Contents

1 Purpose of this consultation paper

1.1 The Electricity Authority Te Mana Hiko (Authority) seeks feedback on seven proposed amendments to the Transmission Pricing Methodology (TPM). These amendments address a range of issues identified through the Authority's ongoing monitoring of the TPM and Workstream 1 of Transpower's operational review[2].

1.2 In proposing these amendments, the Authority is guided by its main objective under section 15 of the Electricity Industry Act 2010 (Act), particularly promoting the efficient operation of the electricity industry for the long-term benefit of consumers.

What is the TPM?

1.3 The TPM governs how Transpower recovers its regulated revenue from transmission customers. At a high level, the TPM comprises three main components:

Connection charges recover the costs of assets that connect individual customers to the interconnected transmission grid. These charges are paid directly by the customers who use those connection assets.

Benefit-based charges (BBCs) apply to new and certain historical investments in the interconnected transmission grid. These charges are allocated to the customers expected to benefit from the investment (referred to as benefit-based investments, or BBIs). BBCs are calculated using two approaches:

- the simple method (for investments under $30 million), which uses historical power flows as a proxy for benefit; and
- the standard method (for investments over $30 million), which uses bespoke and detailed modelling to estimate how the investment affects the system and who benefits.

Residual charges recover the remaining regulated revenue (ie, Transpower's maximum allowable revenue less all other transmission charges). These charges are allocated based on each customer's maximum gross demand and are primarily intended to be non-distortionary.

Proposed amendments

1.4 The Authority proposes the following amendments to the TPM, identified through its ongoing monitoring:

Better implement TPM policy

1. refine the BBC simple method treatment of battery storage, to ensure battery storage is not charged disproportionately compared to other technologies (chapter 4)
2. improve the allocation of costs where Transpower builds anticipatory capacity into connection assets, to better allocate charges to expected beneficiaries[3] (chapter 5)

Technical refinements

3. remove the two-year lag between when a new WACC applies to a regulatory control period for Transpower, as set by the Commerce Commission, and when the TPM

[2] Refer to: TPM Operational Review - Workstream 1 | Transpower

[3] Anticipatory capacity refers to where Transpower builds more capacity into a new or upgraded asset than is required to meet current needs, in order to efficiently facilitate anticipated, but uncertain, growth in load or generation. Building one larger asset or upgrade ahead of demand can be more cost-effective than multiple small upgrades.

requires Transpower to start applying that WACC to calculate benefit-based charges (chapter 6).

1.5 The Authority proposes the following amendments, identified through Transpower's operational review:

Reduce complexity and volatility

4. processing all benefit-based charge (BBC) adjustment events in one annual batch (chapter 7)
5. removing the substantial sustained increase (SSI) adjustment event (chapter 8)
6. extending the first simple method period to enable more timely completion of further operational review work (chapter 9)

Drafting refinements

7. minor, technical amendments to improve clarity and remove redundant provisions (chapter 10).

1.6 These proposals are intended to improve the efficiency and workability of the TPM by better aligning charges with benefits, increasing the predictability of charges, supporting efficient investment in the transmission network and other system assets and reducing administrative costs/effort for all parties.

1.7 Detailed drafting for all proposed amendments and Transpower's Code Amendment Requests (CARs) are provided in Appendix C and D.

1.8 Under the Electricity Industry Act 2010 (Act), the Authority must consult on proposals to amend the Electricity Industry Participation Code 2010 (Code) and a regulatory statement before making changes to the Code.[4] It also requires the regulatory statement to include a statement of the objectives of the proposed amendment, an evaluation of the costs and benefits of the proposed amendment, and an evaluation of alternative means of achieving the objectives of the proposed amendment.

1.9 A regulatory statement for each proposed Code amendment can be found at the end of each chapter.

[4] Chapter 10 of this consultation paper discusses the exception to this requirement in s39(3) of the Act.

2 How to make a submission

2.1 The Authority's preference is to receive submissions in a Word document in the format attached as Appendix A and B.

2.2 Submissions should be emailed to network.pricing@ea.govt.nz with "Consultation paper proposed TPM amendments" in the subject line by 5pm, on:

(a) **7 August 2026** for proposal 2 on anticipatory capacity for connection assets

(b) **24 July 2026** for the other six proposals.

2.3 The Authority will confirm receipt of all submissions.

2.4 If you cannot send your submission electronically, please email network.pricing@ea.govt.nz or call 04 460 8860 to discuss alternative arrangements.

2.5 We will publish all submissions. If you consider that we should not publish any part of your submission, please:

(a) indicate which part should not be published and explain why, and

(b) provide a version of your submission that we can publish (if we agree not to publish your full submission).

2.6 All submissions, including any parts the Authority does not publish, can be requested under the Official Information Act 1982. This means the Authority would be required to release material not published unless good reason existed under the Act.

3 Context and approach

3.1 Transmission pricing matters. It makes up roughly 8% of end users' total electricity bills and, through creating the right incentives, can materially impact electricity system efficiency ie, reliable delivery of electricity at a relatively lower system cost. Getting the TPM settings and implementation right is therefore important so that cost allocation and transmission investment are efficient, for the long-term benefit of consumers.

3.2 The importance of efficient transmission pricing has become even more apparent in the context of:

(a) recent increases in Transpower's allowable revenues from 1 April 2025 following the Commerce Commission's reset of Transpower individual price-quality path,[5] along with broader cost pressures, which together are contributing to upwards pressure on electricity bills for all consumers

(b) the need to facilitate, including through appropriate investment in the transmission network,[6] material investment in new generation as New Zealand electrifies.[7]

3.3 In this context, the TPM must send the right signals – encouraging efficient transmission network use and investment decisions, and appropriate scrutiny of transmission investment.[8] This helps ensure the right decisions are made about building and upgrading transmission assets ie, they are built to the right size, at the right location and at the right time.

3.4 In this chapter we explain:

(a) why substantial TPM reform was needed, and what the 2022 TPM intended to achieve

(b) the process for making implementation and detailed design amendments to the TPM to ensure it is working as intended

(c) what the Authority and Transpower are intending to achieve in this first set of proposed amendments, and what Transpower is targeting in the next tranche of its TPM operational review

(d) how the Authority has assessed each of the proposals in this consultation paper.

The new 2022 TPM

3.5 After a long and contested reform process, the Authority decided on a new TPM in 2022, which was implemented from 1 April 2023. The core aspects of, and rationale for, the new TPM are set out in detail in two key decision papers.[9] In brief, it sought to put more efficient incentives in place by implementing a new benefit-based charging system for interconnection assets. This was intended to:

(a) address poor incentives eg, a peak charge that discouraged consumption even when the transmission network had plenty of capacity left, and encouraged transmission

5 Maximum allowable revenues increased from $840m in 2024/25 to $977 in 2025/26 and $1,135m in 2025/26, and are set to be $1,314m in 2029/30, an increase of 56% on 2024/25. See page 15 of Commerce Commission, 2024 Companion paper to final RCP4 IPP determination.

6 Or transmission alternatives.

7 As well as supporting the electrification of transport and industrial processes, we acknowledge the broader economic contribution that an efficient renewable electricity system can make to further investment in the New Zealand economy, eg, new data centres.

8 Stakeholder scrutiny of transmission investments helps to guard against overbuild of transmission assets that result in excessive and unnecessary costs that must be paid off over multiple generations.

9 Transmission Pricing Methodology 2020 Guidelines Decision paper and Transmission Pricing Methodology Decision Paper 2022.

customers to adjust their use inefficiently (with the result of shifting costs to others, but with little economic benefit to the transmission system)

(b) reduce the unpredictable transmission charge variability inherent in that peak charge

(c) promote scrutiny of new transmission investments by the parties who are expected to benefit from them. This is achieved by giving transmission customers a financial stake in the investment, creating an incentive to assess whether the investment is efficient compared to alternatives,[10] rather than costs being broadly shared across all users (with little financial incentive on any party to scrutinise specific investments).[11]

3.6 The Authority considers this TPM approach – centred around benefit-based charges – continues to make sense as an enduring framework. Those who benefit from investments should pay for them; where there is no useful role for a pricing incentive, charges should be non-distortionary.

3.7 However, since the new TPM was implemented in 2023, areas for improvement have been identified. These include specific aspects where the TPM in practice is not operating as intended.

3.8 These issues are important to address within a framework that continues to reflect the core design intent of the 2022 TPM. The Authority considers that the overall approach remains sound, and that targeted refinements can improve how the TPM operates in practice without altering its fundamental structure. We are therefore committed to ongoing improvement of the TPM, focusing on changes that address identified issues while supporting a stable and predictable framework for investment.

3.9 We specifically acknowledge stakeholder feedback on the new TPM, including through the post-implementation review interviews that Concept Consulting conducted for Transpower.[12] This feedback identified an overall concern about complexity, volatility and uncertainty (CVU) associated with aspects of the new TPM. We agree that it is important to address CVU concerns, as they go directly to the predictability of TPM charges and therefore the ability of customers to act on the incentives those charges are intended to create.

3.10 We note that, while an efficient TPM should reduce system costs over the long run, in the short run the TPM is about allocating a pool of costs. Accordingly, any amendment decision may result in winners and losers, ie, have distributional consequences. We expect these consequences to be relatively minor for the changes proposed in this consultation paper but acknowledge they may be important to stakeholders. While we are open to hearing any views about distributional consequences, the Authority's core mandate is to promote its statutory objective, including the efficient operation of the industry, through the TPM, for the long-term benefit for consumers, and this is reflected in the proposals in this paper.

Process for amending the TPM

3.11 The TPM is set out in Schedule 12.4 of Part 12 of the Code. When we propose an amendment to the TPM, it would be operationalised through an amendment to Schedule 12.4.

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10 Such as distributed generation or demand response.

11 For example, for three of the ten major ($50m+) post-2004 'historic' transmission investments that were intended to be allocated through BBCs under the new TPM, the Authority was able to identify no material benefits for transmission customers that would be commensurate with the costs of these investments. The investments were North Auckland and Northland (cost $473m), Otahuhu Substation Diversity (cost $106m) and Upper South Island Reactive Support (cost $55.2m). All of these investments were approved by the then regulator (the Electricity Commission). Refer para B147, 2019 TPM issues paper.

12 See 2025 TPM Post Implementation Review - summary report.pdf

3.12 Part 12 also sets out the process and requirements for amending the TPM. Part 12 provides that:

(a) the Authority may amend the TPM provided it complies with section 39 of the Act. When consulting on an amendment, the Authority must explain whether the proposed amendment is consistent with the most recent TPM Guidelines and if, not, why it is nonetheless consistent with section 32 of the Act (clause 12.94A)

(b) Transpower may submit a proposed amendment to the TPM to the Authority any time after 12 months have elapsed since the Authority last approved a TPM (clause 12.85)

(c) the Authority may either accept Transpower's proposed amendment for consultation[13] or decline to consider the proposed amendment/refer the proposed amendment back to Transpower on the basis that it either:

(i) does not provide sufficient information for the Authority to make an informed assessment of the proposal (clause 12.90); or

(ii) is not consistent with any determination made under Part 4 of the Commerce Act 1986; the Authority's main objective in section 15 of the Act; or the current TPM Guidelines (clauses 12.89 and 12.91).

3.13 Transpower has proposed four amendments from Workstream 1 of its TPM operational review, which are set out in chapters 7-10 of this consultation paper. These are 'quick wins' identified by Transpower: technical changes to address specific sources of CVU in the near term, and have already been the subject of an initial consultation by Transpower. The Authority has accepted all four of Transpower's proposed amendments for consultation, although for one of these proposals the Authority also presents its preferred variation for consultation.

3.14 The Authority has proposed a further three amendments to the TPM, which are set out in chapters 4-6 of this consultation paper. These arise from continued monitoring of the performance of the TPM by the Authority and are consistent with other recent technical amendments to improve the implementation and efficient operation of the TPM. They:

(a) are changes we think would better align the TPM with its intent

(b) in some cases, seem minor, but in our view are worth doing now before they potentially become bigger issues

(c) in one case (anticipatory capacity for connection assets), seek to unlock potentially larger efficiency benefits in the near term, where the current approach to allocating BBCs may inefficiently hold back investment in new generation and load.

3.15 We have progressed these proposals separately from Transpower's operational review where we consider:

(a) the issue falls outside the scope of that review; or

(b) more timely action is warranted.

3.16 We have appreciated the constructive approach that Transpower has taken to both sets of amendments, including seeking and providing policy and practical feedback. We acknowledge the importance of Transpower and the Authority working closely and

[13] Noting that this does not mean the Authority endorses the proposal and does not in any way bind the Authority when making its final decision on whether to amend the TPM.

constructively on all TPM matters to ensure that any ongoing TPM work is coherent and improves the incentives and practical experience of transmission customers.

3.17 We expect to make a decision on whether to amend the TPM in response to six of these seven proposals in early November 2026, allowing Transpower to then incorporate any changes into its 2027/28 prices. The exception is the proposal relating to anticipatory capacity. We expect that proposal to attract more substantive submissions, so have allowed a longer period for submissions and analysis. We expect to decide on that proposal in early 2027.

3.18 We note that the next workstream of Transpower's TPM operational review is centred on opportunities to evolve and improve the simple and standard methods for allocating BBCs. These are at the heart of the TPM, so Workstream 2 has the potential for bigger gains but is also likely to take more time and be more complex, and we expect this work to continue over the next two to three years.

3.19 We appreciate stakeholders' ongoing engagement in these TPM-related conversations. Transmission customer feedback is critically important to this process. It helps the Authority and Transpower to reduce unnecessary CVU, while better ensuring that the intended TPM incentives are getting through to customers.

Our approach to assessing proposals and options

3.20 We set out below how we have considered the merits of the seven proposals contained in this consultation paper. We will apply the same framework to subsequent amendments that may be identified through the BBC-focussed workstream of Transpower's TPM operational review.

3.21 Our primary assessment criterion is consistency with the Authority's main statutory objective in section 15(1) of the Act, which requires the Authority to "promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers".[14]

3.22 In considering whether the proposals are consistent with the main objective, we have tested them against the 2020 TPM Guidelines (TPM Guidelines), which contain our view on how the main objective applies to transmission pricing. The TPM Guidelines provide:[15]

(a) for a beneficiary pays approach to pricing Transpower's core grid:

  (i) charges reflect the cost of new investment, access to grid, use of grid to transport energy

  (ii) charges are allocated between transmission customers broadly in proportion to their positive net private benefits

(b) that charges should be non-distortionary, eg, avoid creating incentives for existing and potential designated transmission customers to avoid transmission charges in ways that cause economic inefficiency

(c) that the TPM should balance precision with practical considerations (including robustness, simplicity, certainty and administrative and compliance costs).

[14] The TPM does not directly relate to the dealings of industry participants with domestic consumers and small business consumers, so the additional objective in section 15(2) of the Act does not apply.

[15] In the *Authority's intent* section and in *General matters, clause 1*.

3.23 We have specifically considered the impact on stakeholders of the proposals, including in respect of the following:

(a) promoting stakeholder engagement in transmission investment decisions

(b) reducing unintended and disproportionate consequences, both within the TPM and for efficient system-wide investment

(c) reducing complexity and cost

(d) promoting relatively predictable and stable charges.

3.24 We note that our assessment approach is consistent with the assessment criteria applied by Transpower to Workstream 1 of its TPM operational review (which are themselves consistent with the requirements of the Act).[16]

3.25 Where required by section 39 of the Act, we have included a regulatory statement in each chapter that sets out a proposed amendment. We confirm that in putting forward these proposals we have also had regard to:

(a) the Code amendment principles set out in the Authority's 2024 Consultation Charter. In particular, for each of the amendment proposals the Authority has identified a clear case for the proposed amendment, and has provided a summary of the evaluation of the costs and benefits of the proposed amendment

(b) the 2024 Government Policy Statement in accordance with section 17 of the Act. In particular, the proposed amendments seek to improve the efficient operation of the electricity system.

3.26 In each case, the Authority has considered the feasibility and value of quantifying the costs and benefits of the proposed amendments. However, significant information gaps and practical constraints mean that any quantitative assessment would be highly uncertain and unlikely to provide meaningful or reliable insight for submitters or the Authority. These constraints include the difficulty of quantifying important effects such as the efficiency impacts of proposals that improve benefit-based allocations for as yet unknown potential future investments in, say, anticipatory capacity. As such the Authority has therefore prepared qualitative assessments of costs and benefits and welcomes feedback on these assessments.

Q1 Do you agree with the assessment approach and criteria set out in this chapter? Please explain your reasons.

Q2 Do you consider an alternative approach or assessment criteria should be used? If so, please describe these and explain why these would be better.

[16] Refer section 4, Transpower TPM Operational Review 2026 Workstream 1 Proposal Document, 17 April 2026. While we are applying a consistent approach to assessment, this does not of course mean that the Authority and Transpower will always reach the same view.

4 BBC simple method treatment of battery storage

4.1 The Authority proposes to amend the TPM to exempt battery storage from the demand factor that applies to the offtake charge under the simple method. This better reflects how battery storage operates and addresses a risk that large battery storage is allocated disproportionately high benefit-based charges under the simple method.[17]

4.2 We are addressing this issue now because the generation investment pipeline indicates a substantial increase in investment in grid-scale battery storage and we want to ensure TPM charges do not inefficiently discourage or delay that.

Existing TPM treatment of battery storage

4.3 Battery storage will play an increasingly important role in the power system as the proportion of renewable generation, such as wind and solar, increases.

4.4 It has the potential to improve the efficiency of the electricity system by allowing energy to be produced in off-peak periods and drawn on at peak times. This helps electricity consumers to manage exposure to high prices and can mitigate network constraints.

4.5 Battery storage operates as load when charging and as generation when discharging. From a power flow perspective that is a correct reflection of batteries' potential dual use of transmission assets. But functionally we consider that batteries are more akin to dispatchable generation (and other forms of flexibility) and have less in common with end users whose offtake consumes (rather than transforms to store) electricity.

4.6 This specific combination of operation and function has resulted in different allocation approaches to battery storage under the three charge components of the TPM, as set out in Figure 1. Battery storage is generally treated consistently with generation, but not under the simple method used to allocate benefit-based charges.[18]

4.7 These approaches are mostly appropriate, but it has been highlighted to the Authority that the simple method could be an outlier and give batteries disproportionately high charges.

4.8 The Authority considered and consulted on the treatment of battery storage in the late stages of TPM development, when grid-scale battery storage systems had not yet been commissioned in New Zealand.

4.9 The application of the TPM to grid-scale battery storage can now be better understood with the benefit of practical experience, following implementation of the TPM and the commissioning of the Rotohiko (35MW) grid-scale battery near Huntly in 2023, Ruakākā (100MW) in 2025, and Glenbrook-Ohurua (100MW) in 2026.

4.10 Other battery storage projects are at various stages of development. The generation investment pipeline indicates 100MW of battery storage investment is committed for later in 2026 and 277MW is actively pursued for 2027 and 2028. A further 6,500MW of chemical

[17] Battery storage is defined in Schedule 12.4 of the Code as equipment functioning together as a single entity that is able to both (a) take electricity and store the energy in another form; and (b) inject that energy as electricity into the grid, a local network, a non-grid network or consuming plant. The Authority's 2021 consultation paper on the proposed TPM described this as capturing all storage technologies where electricity is a key input and output, including chemical storage (hydrogen) and pumped hydro storage, but excludes non-pumped lake storage, tail water depressed reserve or partially loaded spinning reserve (paras 7.35-7.37). The Authority released a consultation paper on 19 May 2026 (closing 30 June) on wholesale market arrangements for battery energy storage systems (BESS) which proposed to define BESS as 'an energy storage system in which the energy is stored exclusively in electro-chemical form'.

[18] The Authority notes that generation may receive benefit-based and residual charge allocations for its load, to the extent that generation is load (that is, consumes electricity, rather than transforms to store and later discharge that electricity).

battery storage investment is at various stages of development, 3,500MW of which is reportedly to be completed by 2030.[19]

Figure 1 TPM charges and how they treat battery storage

Connection charges

Battery storage would pay all the connection charges allocated to a connection asset if it were the only customer at that connection.

From 1 April 2026, connection charges for shared connection assets are allocated among customers at that location based on the greater of a customer's anytime maximum demand or anytime maximum injection.

Prior to 1 April 2026, the share of connection cost was based on the total of a customer's anytime maximum demand capacity and anytime maximum injection capacity.

The Authority amended the TPM to make this change to avoid battery storage being allocated a disproportionate share of connection charges, compared to other injection technologies.[20] Submissions were largely supportive of this change as it helps to level the playing field for new technologies.

Residual charges

Transpower's load customers pay residual charges based on their historic maximum gross demand. Battery storage is treated as a load customer only to the extent that it is load – that is, based on final consumption (a battery's energy losses), not the total energy taken in when charging.

This design reflects that end consumers of the electricity re-injected by battery storage pay residual charges based on their final demand. Applying residual charges to batteries based on their intermediary demand while also applying residual charges to end consumers based on their final demand would have double-counted demand for the purpose of residual charge allocation and created a cost for batteries not faced by other injection technologies that in our view would have skewed competition.

Benefit-based charges

There are a range of approaches to calculating benefits and, when there is a choice to be made, batteries are treated as generation (except in the case of the Simple Method).

For the standard method of estimating a customer's benefits that inform BBC allocation:

- the quantity-based method treats battery storage as both a load and a generation customer, but offsets expected market disbenefits from injection or offtake against the expected market benefits from offtake or injection (i.e. takes a *net* approach)
- the price-quantity method treats a battery's offtake as a production cost for injection, and this offtake cannot be counted as part of a regional demand group's offtake
- for ancillary services investments, allocations are made to either a regional demand or supply group – battery storage could get an allocation as either offtake or injection, but not both
- for reliability investments, battery storage is treated as a generator
- for resiliency investments, battery storage is treated as a generator, that is, does not attract charges for injection. However, generators do pay BBCs to the extent that they are load, while battery storage offtake is exempt (consistent with offtake being mostly for later discharge)
- for Appendix A (pre-2019) BBIs, battery storage is treated as a generator.

In contrast to the treatment of battery storage under the other methods to calculate its benefit-based charges, the simple method allocates benefit-based charges to battery storage in proportion to its share of both the region's injection and the region's offtake (takes a *gross* approach).

19 See Generation investment pipeline | Electricity Authority.

20 See the Authority's 2024 decision paper: Transmission pricing methodology amendments: a level playing field for emerging technologies

Issues with the existing arrangements

4.11 Under the simple method, historic grid flows are used as proxies for benefit from transmission investment. Simple method allocators are customers' shares of historic offtake and injection in respect of each of 21 investment regions.

4.12 The operation of battery storage can involve both offtake from and injection into the grid, depending on the specific circumstances. When new large battery storage connects, it is charged twice under the simple method – for both offtake and injection – consistent with flows.[21]

4.13 The Authority accepted this logic when it made its final decision to adopt the new TPM in 2022 as part of its reform process (in the context of how the simple method operates).

4.14 However, the simple method also scales up charges for offtake by a demand factor of 1.67.[22] The reason for this demand factor is, in part, to reflect that the value of electricity to end-users is greater than to generators.[23] That scaling-up applies to offtake by batteries also, ie, they are treated like end users, despite that the offtake is to store electricity to later inject (so does not consume or 'use up' electricity in the sense that load does).

4.15 We consider that the logic for applying the demand factor to end users still holds. However, on reflection we are not convinced that it should apply to offtake by batteries. Unlike end-users, battery storage does not consume electricity for final use. The impact of an outage on a battery operator – being the potential loss in earnings if the outage causes it to charge or discharge at a potentially less advantageous time – is much less than the value of lost load to end users. In this way, batteries are like other generation.

4.16 The Authority's current view is that it is inappropriate to treat offtake by battery storage as if it were like other end use demand, and that by doing so the simple method may materially overstate the benefit of offtake to battery storage. This would lead to battery storage attracting unduly higher benefit-based charges compared to generation and other technologies and sources of flexibility that battery storage competes with.

4.17 Inconsistent treatment of battery storage compared to competing technologies may discourage otherwise efficient investment in battery storage. That could lead to an inefficient mix of energy generation sources, higher electricity prices, and security of supply issues (noting the importance of battery storage as part of the solution in addressing winter peak challenges).

Proposed amendment

4.18 We propose a technical amendment to the TPM to ensure that the demand factor in clause 64(2) of the TPM does not apply to simple method allocations for battery storage offtake.

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21 The impacts described in this section are lessened for large plant embedded with a load or generation customer when simple method allocators get recalculated in subsequent simple method periods, so they become net measures for future grid investments. As noted by Transpower (2025) in TPM Information Sheet - Battery Storage.pdf: "In general, embedded battery storage is not explicitly accounted for in calculating BBC allocations. Allocations for embedded battery storage are implicit in the allocations of the relevant direct connect or distribution customers."

22 Strictly, under clause 64(4) of the TPM the Demand Factor is defined as 'RNPBs total / RNPBd total x 1.67', which would be 1.67 if power flows (used as proxies for benefits) are 50:50. Also see the next footnote.

23 See pp 27-33 of the Authority's 2022 TPM Decision paper.pdf. In the 2022 TPM decision paper the Authority concluded that a 62.5% to 37.5% load to generation weighting would better reflect the distribution of benefits from simple method investments (rather than the ~50:50 implied by power flows alone) – and 62.5 / 37.5 = 1.67. This conclusion was based on 'the logic that outages have a greater impact on consumers than generators (as reflected in the value of lost load relative to wholesale prices as a broad indicator of value)', and that over-allocating costs to generation risks inefficiently delaying new generation entry which would not be for the long-term benefit of consumers.

4.19 This proposed adjustment would be made via clause 61 of the TPM, effectively reversing the application of the demand factor in clause 64. This would leave battery storage offtake valued the same as an equivalent amount of injection. That is, charges would be proportionate with flows, regardless of whether the electricity is for offtake or injection, and this would address disadvantages set out at paragraphs 4.16 and 4.17.

4.20 In practice, the implementation should be relatively straightforward in respect of adjustment events (including for embedded batteries), and the calculation of allocators for offtake by battery storage that is directly connected to the grid in subsequent simple method periods.

4.21 Transpower has noted that implementation could involve some complexities. It noted it may need to treat battery storage differently from other customers in its pricing system. It also noted the implementation may be more complex if it needed to apply the proposal to embedded battery storage when Transpower recalculates simple method allocators for future simple method periods. This is because those allocators are based on offtake and injection of the host customers (a net measure, with allocations for embedded battery storage implicit in the allocations of the host customers).

4.22 We consider that these implementation questions are unlikely to impact the core rationale for this proposal. We note there are different ways to address this point[24], and Transpower can consider the treatment of embedded battery storage in future simple method periods during its Workstream 2 of its operational review that will address the simple method.

Other options considered

4.23 We identified a number of alternative approaches to the treatment of battery storage under the simple method, but consider these options would either not be effective, or introduce greater complexity or inefficiencies:

(a) **Allocate simple method charges on the greater of a regional customer group's contribution to offtake *or* (rather than *and*) injection:** This could involve amending clause 59(2)(a). However, this would not address the demand factor applying to battery storage offtake. So it would be complementary to the proposed amendment.

While we understand the logic to this approach, it is a more fundamental change which also risks under-allocating transmission charges to battery storage where it does rely on the grid for both offtake *and* injection which, under the design of the simple method, are proxies for benefits. This could occur in situations where battery storage is connected separately (not located near generation or load). In our view this level of change would be better considered by Transpower during Workstream 2 of its operational review.

(b) **Treat battery storage as injection-only (include only in the simple method supply group**): This option would only count injection. That would reflect that battery storage is like generation, and it would bypass the demand factor issue.

A disadvantage is that, where battery storage uses the grid for offtake but not injection, it may result in battery storage not paying any simple method BBCs at all, despite relying on the grid. There is therefore a material risk that this approach would systematically undercharge some configurations of grid scale batteries.

[24] For example, options could include requiring the separate identification and calculation of embedded battery storage offtake to ensure this does not attract the demand factor, or (as seems appropriate) to continue the current approach without such separate identification in future simple method periods, where simple method charges for the host customer are based on a net measure (see footnote 21) – if a host customer then passes on transmission charges to embedded battery storage for offtake it can ensure these charges exclude the impact of the demand factor.

(c) **Exempt battery storage from BBCs:** This reflects some stakeholders' views that any benefit that battery storage gets from the grid should be fully offset to reward battery storage injection for supporting the grid and deferring or avoiding transmission investment.

However, this would create another inconsistency in the TPM, by treating battery storage different to generation, giving battery storage a competitive advantage. Further, the Authority considers that wholesale market nodal prices already provide batteries (and distributed generation) efficient, market-based rewards to discharge during times of high demand or transmission constraints. An additional cost advantage to battery storage would be inefficient.[25]

To the extent that battery storage could be a cost-effective transmission alternative, if it were to operate beyond and in addition to a battery's operation in response to nodal price signals, then Transpower could enter into grid support contracts to procure such services from batteries.

4.24 The Authority acknowledges that Transpower plans a review of the simple method as part of Workstream 2 of its operational review, which may lead to options that could more fundamentally align the treatment of battery storage under the simple method with that for other technologies.

4.25 However, the direction, outcome and implementation timing of any amendments are currently unknown, and the Authority considers it justified to progress the proposed amendment now to avoid battery storage attracting disproportionate transmission charges and so discouraging efficient investment (noting the amount of grid scale battery storage investment in the pipeline as summarised at paragraph 4.10). Should Workstream 2 recommend additional amendments to further refine how the simple method treats battery storage, we will of course be open to considering them on their merits.

4.26 The box at the end of this chapter provides some numerical examples to illustrate the impact of the current treatment of battery storage on allocations under the simple method, as well as how the Authority's proposal may ameliorate the risk of disproportionate impacts. It also illustrates the impacts on allocators under the other options considered above.

Regulatory statement

Objective of the amendment

4.27 The objective of the proposed amendment is to reduce the risk that battery storage is allocated disproportionately high transmission charges, inconsistent with the application of the TPM to other supply technologies, discouraging efficient investment in battery storage.

Proposed amendment

4.28 The Authority proposes to amend clause 61(1) of the TPM so that the demand factor is reversed out and does not apply to offtake by battery storage when calculating BBCs under the simple method.

Proposal's benefit expected to outweigh costs

4.29 The amendment would improve the extent to which benefit-based charges calculated under the simple method reflects the net private benefits of battery storage. More efficient simple

[25] See the Authority's Distributed Generation Pricing Principles Issues Paper 2025.

method allocators would avoid disproportionately high charges for battery storage that could discourage investment in battery storage.

4.30 The long-term benefits to consumers from more efficient transmission price signals are likely material (through lower electricity prices long term and more reliable supply), noting the importance of battery storage as part of the solution in addressing winter peak challenges, and the amount of potential investment in battery storage that is recorded as being at various stages of development.

4.31 There will be implementation and administration costs though these are expected to be modest compared to the long-term efficiency gains enabled by the proposal.

4.32 The Authority considers that the expected benefits of the amendment will outweigh the costs.

Proposal better than other options that have been identified

4.33 The Authority considered a range of alternative options for the treatment of battery storage under the simple method, including treating batteries as injection-only, allocating charges based on the greater of injection or offtake, and exempting batteries from benefit-based charge. These were discussed and assessed at paragraph 4.23.

4.34 These options are not progressed as they would either introduce greater complexity, risk under-allocating charges, or create inconsistencies with the broader TPM framework.

4.35 The proposed amendment is therefore considered the most proportionate response to the identified issue.

4.36 It can be progressed ahead of the outcome of Workstream 2 of Transpower's operational review, which will consider opportunities for improvement to the simple method and standard method for calculating benefit-based charges.

Proposed amendment complies with section 32(1) of the Act

4.37 The Authority considers that the proposed amendment is desirable to promote the efficient operation of the electricity industry and thus complies with section 32(1) of the Act.

4.38 It does so for the reasons set out above, including by ensuring the simple method allocators more accurately reflect the benefits that battery storage receives from transmission investment, reducing price distortions.

4.39 By levelling the playing field with respect to other flexible generation, it also contributes to promoting competition and reliability of supply in the electricity industry.

Proposed amendment complies with the intent of the 2020 TPM Guidelines

4.40 The Authority considers the proposed amendment is consistent with the intent of the TPM Guidelines.

4.41 The proposal would better align BBCs calculated under the simple method with the positive net private benefits battery storage obtains from grid investments.

Q3 Do you agree that offtake by battery storage should be exempt from the Demand Factor? Please explain your reasons.

Q4 Do you prefer any of the alternative options discussed for the treatment of battery storage under the simple method? Please explain your reasons.

Q5 Do you agree that the proposed amendment for battery storage offtake should be made ahead of Transpower's next phase of its operational review, when it will review the simple method? Please explain your reasons.

Q6 Do you have any comment on the drafting of the amendment to the treatment of battery storage in Appendix C?

Figure 2 Stylised examples of options for simple method allocators for battery storage

When grid-scale battery storage first connects, it will be treated as if it is grid-connected. This means that both offtake and injection are counted when calculating simple method allocators.

These allocators are for the remainder of the simple method period during which the battery first connects (and in place for the life of the investments made during that period).

When the simple method period ends and allocators get reset for a further five years, embedded battery storage or any other embedded large plant will not be explicitly measured. Their use is implicit in their host customers' offtake and injection, which are net measures. Host customers may pass through charges to embedded plant.

The stylised examples start with a '2 locations, 2 customers' grid – a generator that injects 160 units into the grid, and a demand centre that has an offtake of 160 units. (We ignore losses and time.)

Injection and offtake each account for 50% of power flows. The demand factor of 1.67 is applied to offtake's offtake, and shares are calculated (and if necessary scaled to sum to 1), so the generator's allocation is 37.5% and load's allocator is 62.5%.

	Injection	Offtake	RNPB or NPB prescaled		Final allocation
Generation	160		160	0.375	0.375
Load		160	267.2	0.625	0.625
Total	160	160	427.2	1.00	1.00

The following scenarios show the resulting allocators when battery storage connects, assuming it has a capacity to store and discharge 60 units (ignoring losses, although in practice these are measured).

Status quo – adjustments under current arrangements when battery storage enters.

Battery's injection is allocated 60 / (160+267.2) = 0.14, and offtake is allocated 60*1.67 = 100.2, and 100.2 / (160+267) = 0.235.

Allocators are then scaled to add to 1.

	Injection	Offtake	RNPB or NPB prescaled		Final allocation
Generation	160		160	0.375	0.272
Load		160	267.2	0.625	0.455
BESS inject	60		60	0.140	0.102
BESS offtake		60	100.2	0.235	0.171
Total flows	220	220		1.375	1.000

Do not apply demand factor to battery offtake.

Scenario represents the Authority's proposal.

The 1.67 Demand Factor is not applied to battery offtake.

After allocators are scaled, the allocator for battery storage offtake (0.11) is the same as that for injection (0.11).

	Injection	Offtake	RNPB or NPB prescaled		Final allocation
Generation	160		160	0.375	0.292
Load		160	267.2	0.625	0.488
BESS inject	60		60	0.140	0.110
BESS offtake		60	60	0.140	0.110
Total flows	220	220		1.281	1.000

Greater of either offtake or injection

Assume offtake will be greater (it would be in adjustment events when large plant is treated as if grid connection).

Therefore, no allocation for injection. The demand factor still applies to battery storage offtake, and the final allocator is 0.19.

	Injection	Offtake	RNPB or NPB prescaled		Final allocation
Generation	160		160	0.375	0.303
Load		160	267.2	0.625	0.507
BESS inject	60		60	-	-
BESS offtake		60	100.2	0.235	0.190
Total flows	220	220		1.235	1.000

Treat as injection only

Only battery storage's injection would be counted.

A variant of this option is to use the greater of injection or offtake for the injection input in the table (or combine with not applying the demand factor to a battery's offtake).

	Injection	Offtake	RNPB or NPB prescaled		Final allocation
Generation	160		160	0.375	0.328
Load		160	267.2	0.625	0.548
BESS inject	60		60	0.140	0.123
BESS offtake				-	-
Total flows	220	160		1.140	1.000

5 Anticipatory capacity

5.1 The Authority proposes an amendment to clause 27(2)(d) of the TPM to require Transpower to use the standard method – instead of the simple method – for calculating net private benefits for allocating the part of the capital cost of anticipatory connection assets (50%) that is not socialised.

5.2 This would address the issue that predetermined simple method allocators that are based on historical flows – and which Transpower is currently required to use – may not allocate costs in a way that reflects expected benefits to the primary beneficiaries of anticipatory capacity.

Existing arrangements

5.3 Anticipatory transmission investments build capacity ahead of time to facilitate anticipated, but uncertain, growth in load or generation. Building one larger upgrade ahead of demand can be more cost-effective than multiple small upgrades.[26]

5.4 Who should pay for anticipatory capacity before all the anticipated load or generation growth turns up is contentious. Issues include who should carry the cost if anticipated growth does not eventuate, and how to avoid imposing costs on parties who get little or no benefit.

5.5 The TPM addressed these issues for new or upgraded connection assets by allowing Transpower to recover the cost of the anticipatory component of the asset as follows:[27]

(a) 50% of the capital cost is socialised among all connection customers through connection charges

(b) 50% of the capital cost is allocated to existing customers that are expected to benefit from the anticipatory investment[28] through BBCs using the simple method to calculate charges,[29] with the allocation limited to:

(i) regional supply groups if the anticipatory capacity is for a future increase in offtake

(ii) regional demand groups if the anticipatory capacity is for a future increase in injection.

5.6 This approach was to strike a balance between:

(a) ensuring there are incentives on transmission customers to scrutinise proposals for anticipatory capacity to help mitigate the risk of inefficient overbuilding that is present when costs are fully socialised

[26] Building anticipatory capacity addresses a co-ordination failure when the timing of the necessary network upgrade and the investment it is meant to support are not aligned. Addressing such failures may support not just more cost-effective transmission solutions but also investment in load or generation that may otherwise be delayed or discontinued.

[27] As the anticipated load or generation connects, the anticipatory capacity costs revert to standard connection charges to these customers.

[28] Even if they are not the primary beneficiaries. So, for example, for anticipatory connection capacity that is intended to support an increase in injection, the primary beneficiaries are expected to be the new generators that have yet to turn. However, downstream load is also likely to benefit from this investment as it will enable more electricity to be exported, putting downwards pressure on prices.

[29] Even if the anticipatory investment cost is above the normal $30m threshold for the simple method.

(b) avoiding disproportionately high charges in regions with a low number of beneficiaries, ie, an overly strong price signal potentially preventing investment in an efficient extra increment of capacity.[30]

5.7 However, since the implementation of the TPM in 2023, concerns have been raised that the anticipatory capacity provisions may not lead to appropriate allocations for the 50% charged to expected beneficiaries. This was first raised in respect of proposed investments to unlock renewable generation potential in Northland,[31] but has highlighted a potential wider issue. Proposed investments in the Wairarapa have raised related questions in respect of anticipatory *inter*connection assets (see the interconnection section at the end of this chapter).

5.8 If the allocation methodology is not working well, it needs to be resolved promptly to avoid undue delays in or abandonment of any efficient opportunities to invest in transmission, generation or load.

5.9 The Authority's priority is to address identified issues with the method to allocate the 50% of capital cost for anticipatory connection assets that is to be allocated to customers expected to benefit.[32] The Authority is not seeking to revisit its earlier decision that some portion of the cost of anticipatory capacity should be recovered through benefit-based charges to ensure transmission customers have clear incentives to scrutinise proposals, as a counter to the risk of inefficient overbuilding that is present when costs are fully socialised.

Issues with existing arrangements

5.10 The simple method is intended to be a repeatable, mechanised process that can be applied regularly to regular and lower value Transpower transmission investments (all investments below $30m).

5.11 In general, the simple method allocates the cost of transmission investments based on predetermined shares, without any discretion by Transpower. These shares are based on historical power flows within and between regions. This contrasts with the standard method, which takes a bespoke, forward-looking approach to identifying who benefits from transmission investment.

5.12 The simple method tends to identify within-region offtake as the main load beneficiaries in most simple method regions (see Figure 3). This reflects that the simple method was designed with repeat expenditure (maintenance and replacement of existing grid assets) in mind.

5.13 When applied to the 50% of anticipatory capacity costs charged to expected beneficiaries, historical power flows mean that the simple method would allocate the costs of anticipatory capacity to unlock generation mostly to within-region load. This allocation can be appropriate (and could be similar to that which results from applying the standard method).[33]

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30 Electricity Authority, 2022 TPM Decision paper, pp15-20. Transpower had noted that the simple method may not adequately identify beneficiaries of anticipatory capacity when that led to a change in grid flows. However, the Authority considered that 'even if grid flows change, the initially identified regional beneficiaries will likely benefit significantly due to [reductions in average wholesale prices]' and decided that the 50/50 approach to anticipatory capacity struck the right balance between the different considerations.

31 For a project description of this example see Transpower, Top Energy, Northpower, 2024, "Resilience, reliability and an Energy Bridge". The Authority's proposal in this paper addresses the broader underlying question raised by this project. The Authority understands from Transpower that it is not currently investigating plans to increase the capacity of its connection assets in the Northern region. Transpower concluded, in discussion with Top Energy and Northpower, that at the time Transpower's investment options were not viable as they would be unlikely to pass the Investment Test (without which the anticipatory capacity provisions would not apply).

32 See TPM Information - Connection charges - Anticipatory investment and Type 2 FMD v3.pdf

33 Transpower provided the Authority with an example that suggested this to be the case under certain circumstances.

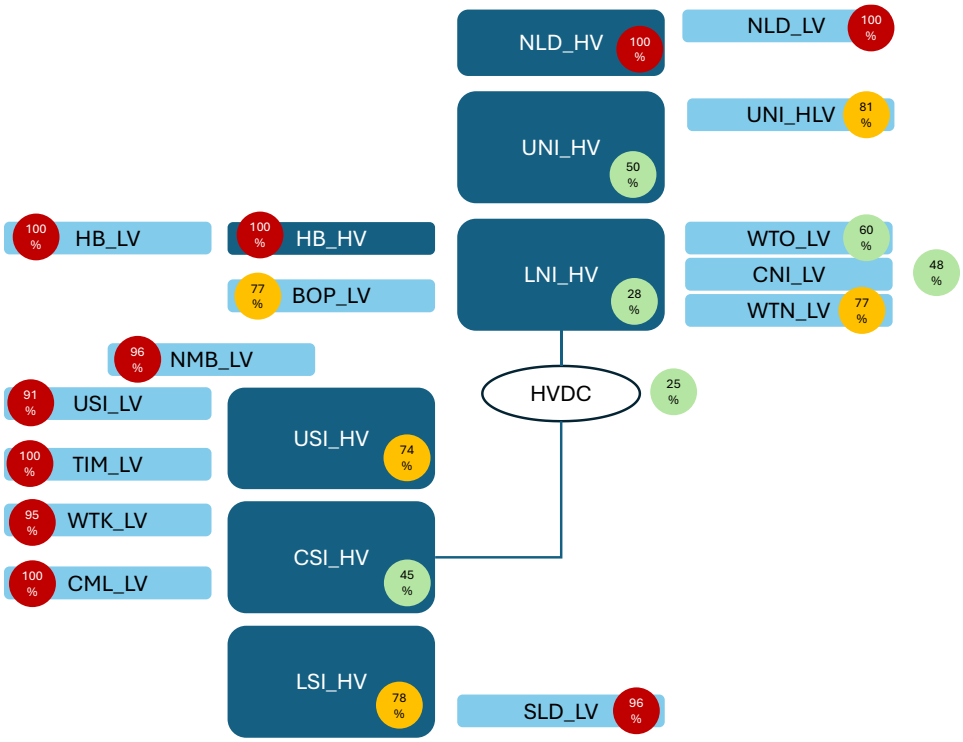
5.14 However, there are also situations where investment in load or generation – enabled by the anticipatory capacity – would fundamentally change the power flows compared to the past. Historical flows are then no longer reasonable proxies for who benefits.

5.15 The latter scenario appeared to be the case in the example of the anticipatory capacity that was being considered for Northland. Subsequent generation investment in Northland would likely change Northland from a net importer of power to a net exporter of power. It seemed likely that the main beneficiaries of the export enabled by that anticipatory capacity investment would be in other regions, likely Auckland.

5.16 Even if local demand customers also benefit from this increase in generation in the region through a reduction in average wholesale prices, the benefits to that group could be small relative to carrying all the cost of anticipatory capacity (particularly when the regional demand group is small).

5.17 This cost concentration issue (allocating almost the entire 50% to within-region load) applies across the country. The chart below illustrates the concentration of simple method allocators for load customers in low voltage simple method regions outside large population areas. (The percentages in the chart show the share of total offtake linked to a simple method region that is accounted for by the top five customer connection locations).

Figure 3 Percentage allocation of offtake customers' shares by region



5.18 The Authority now has a better understanding of the impacts of the simple method having been designed to allocate low value asset maintenance and replacement costs within the region where the benefit-based investment is being undertaken.

5.19 We appreciate that Transpower is reviewing the simple method in Workstream 2 of its operational review. But in the specific context of anticipatory capacity, it is already clear that the simple method may not be well suited to larger transmission upgrades that can materially change broader market dynamics, including prices, quantities, and reliability outcomes. In such situations historical power flows are not a reasonable proxy for positive net private benefits.

5.20 The Authority considers that the use of the simple method to determine allocations is not fit for purpose in situations where connection upgrades are proposed for a region to enable significant increases in injection where that would significantly alter power flows and benefit consumers in other regions.

Proposed amendment

5.21 The Authority proposes a minor amendment to clause 27(2)(d) of the TPM to require Transpower to use the standard method, rather than the simple method, for calculating net private benefits for allocating the part of the capital cost of anticipatory connection assets that is not socialised across connection investments. See Appendix C.

5.22 The standard method provides for bespoke market modelling of the impact of the transmission investment[34] and is thus better able to identify the beneficiaries, and the extent to which they may benefit over time from a proposed transmission investment that may change market dynamics, compared to the simple method which relies on pre-determined allocators based on historic flows.

5.23 We consider this amendment to be consistent with the Authority's main statutory objective and with the TPM Guidelines because it:

- is an immediate, effective solution to the cost allocation issues for anticipatory capacity by better identifying expected beneficiaries
- promotes efficiency as customised modelling achieves allocations that better reflect positive net private benefits
- promotes appropriate scrutiny of anticipatory investments by their expected beneficiaries, as opposed to the simple method, which at least in some circumstances promotes inefficient opposition to investments when costs are being allocated to the wrong party.[35]

5.24 For these three reasons using the more precise standard method would strike the right balance between precision and practicality, considering also that:

- using the standard method would increase administration costs as it requires more effort and judgement from Transpower (but there would be less dispute about whether simple method charges are proportionate)
- the additional administrative burden should not be too high as anticipatory capacity investments are unlikely to be common, and extra effort is likely justified as it supports scrutiny of non-routine transformative investments that involve part-socialisation of cost.

5.25 In our view the issue needs to be addressed as soon as possible given anticipatory capacity investments are being considered now, and cost allocation issues should not unintentionally hold up any efficient investments.

5.26 We are aware that Transpower has some concerns about the way in which the standard method for BBCs currently operates, which it intends to address in the next workstream of its TPM operational review. Those concerns include:

(a) the complexity of and time taken for standard method modelling

[34] Eg, using factuals and counterfactuals to assess the net private benefits of investments.

[35] We note that the Commerce Commission applies scrutiny to Transpower expenditure, including to specifically approve major capex investments and anticipatory capacity investments. We appreciate that the Commission is well placed to perform this role. By providing incentives on intended beneficiaries to scrutinise anticipatory capacity investments, we seek to ensure that the inputs to the Commission's process are as robust as possible, including from transmission customers because they will face the costs as well as benefits from such investments.

(b) the timeliness of transmission customers receiving information on BBC allocations they can expect to pay for the investment (risk that this occurs too late in the process for them to influence the investment decision)

(c) structural aspects of the BBC process Transpower must follow, including specifically the choice between a quantity-based (clause 51) and price-quantity-based (clause 52) assessment of net private benefits.

5.27 We appreciate these concerns and welcome the chance to work with Transpower to streamline the process for allocating costs for major capital investments in the operational review workstream and facilitating more timely indications to transmission customers of expected BBC allocations.

5.28 But, in our view, these concerns do not appear to outweigh the benefits of our proposal that the standard method should be used for allocating anticipatory capacity investments given:

(a) the simple method is not well suited for these situations

(b) anticipatory capacity investments do not appear to be proposed frequently, and we anticipate that any which are proposed would likely be large (so it is worth investing time and effort into the modelling and analysis and supporting scrutiny by transmission customers)

(c) the standard method, while complex, is built on top of processes and data that Transpower already has in place for its business planning

(d) In our view it is not for the long-term benefit of consumers to socialise these investment costs because that weakens incentives for transmission customers to scrutinise proposals for anticipatory capacity, necessary to mitigate the risk of inefficient overbuilding that is present when costs are fully socialised.

5.29 We acknowledge that the standard method involves modelling assumptions and that results may be sensitive to these inputs. This reflects the forward-looking nature of the analysis.

5.30 In our view, these challenges can be appropriately managed through established modelling processes, as routinely applied in assessing major transmission investments, and do not outweigh the benefits of more accurately identifying beneficiaries.

Other options considered

5.31 Other options which the Authority has identified that may address the issues above are to:

- amend the simple method
- introduce a new bespoke allocation method.

5.32 Table 1 summarises the Authority's current assessment of the identified options.

5.33 Consistent with the focus on improving the TPM, the Authority only considered options aimed at improving the allocation of the benefit-based component of anticipatory investments, rather than a revision of the overall funding regime, and in particular full socialisation of these costs. While full socialisation would avoid the identified issues, it creates others that would be inconsistent with what the TPM seeks to achieve. It risks weakening incentives on transmission customers to test for efficient investment, to the long-term detriment of electricity consumers.

5.34 While the Authority's preferred approach is to only allow the use of the standard method to determine benefit-based allocations for anticipatory capacity investments, two other ways in which the standard method could be applied have been considered. See Table 2. In particular, it could be:

- required, that is, the only available method. This is preferred because (in contrast to the other options) it is a simple rule that provides greater certainty that allocators will be reasonable proxies for net private benefits
- required if certain conditions are met for example, that the anticipatory investment and thus cost is large relative to current assets or charges, and benefits are intended to be inter-regional rather than intra-regional
- left to the discretion of Transpower

Table 1 Options for allocating the benefit-based component of Anticipatory Capacity

Option:	Assessment
Use standard method	Code change can be implemented immediately as method draws on established modelling processes and capability. Addresses core issue, as customised modelling to reflect specific circumstances and measure market impacts can better allocate on net private benefits, and additional scrutiny enabled by standard method modelling. Promotes efficiency. Increases administration costs for Transpower.
Amend simple method	Not an obvious, easy or timely fix. This may be an option over a longer timeframe (maybe as part of Workstream 2 of Transpower's operational review), but it is unclear how an amendment could work if the simple method continues to be based on power flows. We would expect a change to the simple method that would also address this type of issue would take substantial time to develop and test.
New bespoke method	Has potential to be the best option but would take material time for Transpower to develop. Likely to work in combination with changing the allocator to the standard method at least in the interim. Allows Transpower to investigate a new bespoke option for benefit-based allocation of anticipatory capacity costs on a less urgent timeframe while getting a workable solution in place to avoid cost-allocation being the cause of hold-up of anticipatory capacity proposals.

Table 2 Options to put conditions on the use of standard method

Option:	Assessment
Standard method required	Certainty: the method is designed to estimate reasonably accurately customers' net private benefits different market scenarios. Adds cost as simple method may be able to produce reasonable allocators at lower effort under certain situations than bespoke market modelling. Impact may be mitigated if Transpower is only considering a relatively small number of anticipatory capacity investments, ie, assuming current rates continue.
Standard method required if conditions are met	Retains ability to use simple method, which is intended to be a lower-cost way to establish reasonable benefit-based allocators. Extra decision on which method applies adds some complexity and uncertainty as it relies on a likely arbitrary boundary (what is a 'large' change in cost or scale?).
Standard method discretionary	More flexibility compared to adopting the standard method only if conditions are met. Increases uncertainty as it increases the scope for dispute on which method to apply. It creates incentives for affected parties to favour the method that lowers their charges, rather than the one that promotes efficient allocation (charges that best reflect net private benefits).

Anticipatory capacity for interconnection assets

5.35 In Workstream 1 of its TPM operational review, Transpower has asked whether there is also a policy question to address in relation to anticipatory capacity for interconnection assets. Transpower says: "Under the current TPM, existing load customers mostly pay for these upgrades until the new generators connect, meaning the existing load customers fund benefits ultimately received by future generation customers (or, potentially, vice versa)." This question is further discussed in section 10.2 of Transpower's March 2026 Workstream 1 consultation paper.[36]

5.36 At a high level, the Authority wants to encourage Transpower to make efficient anticipatory capacity investments for interconnection assets, as well as for connection assets. And as with connection assets, we want to ensure that anticipatory investments for interconnection assets are appropriately scrutinised to reduce the risk of overbuild.

5.37 Our starting position for interconnection assets is therefore that anticipatory investment costs should be met by beneficiaries. This should be able to be achieved through the normal BBC allocation approach, hence the Authority not including a specific anticipatory capacity mechanism for interconnection as part of the previous TPM reform process.

5.38 For anticipatory capacity build into interconnection assets that enable more injection, we remain of the view that the initial (and ultimate) beneficiaries are downstream load (until new generation enabled by the investment turns up and is allocated a share of costs under the existing rules). Efficiently facilitating more generation entry and competition will benefit downstream load through lower prices. As such, it would be consistent with the TPM Guidelines to allocate BBCs in relation to these assets to downstream load directly, until the new generation turns up. This core logic underpinning our approach to anticipatory capacity remains sound in our view.[37]

5.39 We acknowledge that, for our approach to be effective, the TPM must identify the appropriate beneficiaries, the analysis of costs and benefits of any anticipatory capacity transmission must be robust and the Commerce Commission must apply adequate scrutiny (which can only occur if all interests are adequately represented).

5.40 As identified earlier in this chapter, we have concerns about the first of these points. The simple method for BBCs does not appear to be well suited for this type of investment, ie, in some circumstances it may allocate costs to the wrong transmission customers. That seems to be a potential problem for interconnection anticipatory capacity as well.

5.41 We expect the next phase of Transpower's TPM operational review to look at all relevant questions regarding whether the simple (and standard) method is fit for purpose. We would welcome stakeholder feedback though on whether there is a specific issue for interconnection anticipatory capacity that needs to be looked at on a faster timetable.

5.42 For completeness:

(a) We do not consider that socialising the whole full cost of anticipatory capacity investments and relying on Commission scrutiny to prevent overbuild will be effective. The effectiveness of Commission scrutiny depends substantially on all perspectives being put to it robustly, including the case against any proposed investment. If costs are

[36] TPM Operational Review 2026 Workstream 1 - Consultation Document

[37] Over time we would also expect that electricity prices for consumers in a competitive market would include transmission costs, ie, ultimately these costs are passed through.

fully socialised, we are not confident that there will be sufficient incentives for the counter-case to be made.

(b) We do not agree with the suggestion that anticipatory capacity costs for interconnection assets should be *back charged* to new generators as they connect. While we understand the rationale for this view, it would:

(i) create an extra cost hurdle for this new generation, which risks delaying entry, especially if the back charge increases over time

(ii) put this new generation at a temporary cost disadvantage compared to other generation, ie, skew competition

(iii) be inconsistent with the approach to determining how subsequent movers contribute to the first mover's capital cost of connection assets.

(c) In our view neither of these outcomes is consistent with the long-term benefit of consumers.

Regulatory statement

Objective of the amendment

5.43 The objective is to ensure that the benefit-based allocation of 50% of capital cost of anticipatory connection assets that is not socialised is allocated to the likely beneficiaries of the investments (putting incentives to scrutinise investment in the right place to promote efficient investment in anticipatory capacity).

Proposed amendment

5.44 The Authority proposes a minor amendment to clause 27(2)(d) of the TPM to require Transpower to use the standard method for calculating net private benefits for benefit-based allocation of 50% of the capital cost of anticipatory connection assets.

Proposal's benefit expected to outweigh costs

5.45 The proposal would promote the efficient operation of the electricity industry by resulting in transmission charges being allocated to the likely beneficiaries of the connection investments.

5.46 Over the long-term it will also reduce the cost of transmission, by ensuring the likely beneficiaries have incentives to scrutinise anticipatory investments, promoting more efficient transmission and non-transmission solutions.

5.47 It is an existing method, so can be implemented immediately.

5.48 There would be additional administrative costs associated with the use of the standard method to estimate allocations based on positive net private benefits, rather than the application of pre-determined simple method allocators.

5.49 The Authority considers that the administrative costs would be modest in the context of:

(a) the size of any anticipatory investments

(b) the likely number of anticipatory investments that Transpower would be modelling under the standard method (not many based on experience to date)

(c) the potential gains that accrue over the long-term.

5.50 These costs will also be offset by the efficiency gains that can be expected from the promotion and support of additional scrutiny of the cost and benefit of investment proposals.

5.51 The Authority considers that the expected benefits of the amendment will outweigh the costs.

Proposal better than other options that have been identified

5.52 The Authority considered a range of alternative options to address the problem identified with current provisions – the options and our assessments of them are summarised in Table 1.

5.53 A key disadvantage of most of the other potential options is that they would take a significant amount of time to develop. Adopting the Authority's preferred option does not preclude from alternative approaches being developed for future consultation, but it addresses the clear issue with using the simple method under the current approach (even if imperfectly) in the meantime and reduces risks of inefficient decisions ahead of the development of more comprehensive solutions in future.

5.54 The Authority considers that sub-options that put conditions on the use of the standard method (Table 2) add unnecessary complexity and uncertainty.

Proposed amendment complies with section 32(1) of the Act

5.55 The Authority considers that the proposed Code amendment is desirable to promote the efficient operation of the electricity industry, and thus complies with section 32(1) of the Act. It does so by ensuring that charges for investments are better targeted at the likely beneficiaries of the transmission investments than is currently the case.

Proposed amendment complies with the intent of the 2020 TPM Guidelines

5.56 The proposal complies with the intent of the TPM Guidelines as it seeks to ensure that costs of anticipatory connection assets that are to be allocated based on customers' benefits reflect their share of positive net private benefits and strike an appropriate balance between economic benefits and costs of precision and practical considerations.

Q7 Has the Authority correctly described the nature and root cause of the cost-allocation issues for anticipatory connection assets? Please provide your reasons.

Q8 Do you agree with the proposal to require the use of the standard method to allocate the 50% share of capital cost of anticipatory connection assets that is to be recovered through benefit-based charges? Please give your reasons.

Q9 Do you agree with the proposal that the requirement to use the standard method for allocating the cost of anticipatory capacity should progress ahead of Transpower's operational review of the benefit-based charging methods? Please state your reasons.

Q10 Do you agree that the cost of anticipatory interconnection assets should be met by beneficiaries through the normal BBC allocation approach? Please explain your reasons.

Q11 Can you identify better options than those proposed by the Authority to allocate the cost of anticipatory assets? Why would your option be better?

Q12 Do you have any comment on the drafting of the amendment to the treatment of anticipatory connection assets in Appendix C?

6 Applying updated WACC without a lag

The Authority proposes to remove the two-year lag between when the weighted average cost of capital (WACC) as determined by the Commerce Commission comes into effect at the start of each regulatory control period for Transpower, and when the TPM requires Transpower to start applying that WACC to calculate benefit-based charges.

The existing arrangements

6.1 The Commerce Commission determines the maximum allowable revenue that Transpower can recover, which includes a return on capital (ie, the return Transpower, and ultimately its shareholder, earns for investing in transmission assets). The TPM determines how Transpower recovers that revenue.

6.2 The Commerce Commission determines the WACC that applies during each five-year RCP.[38] The WACC varies between RCPs, sometimes by a lot, as Table 3 shows.[39]

Table 3 WACC used in calculation of Transpower's regulatory revenue

	RCP1	RCP2	RCP3	RCP4
WACC	8.05%	7.19%	4.57%	7.10%

Source: Vanilla WACCs from the Commission's Transpower cost of capital determinations applicable to past and current regulatory control periods.

6.3 Under the current TPM there is a two-year lag between the start of a new RCP when the updated WACC comes into effect and when the new WACC starts being used by Transpower to calculate Benefit-Based Charges (BBCs).[40]

6.4 In other words, the earliest that the WACC for RCP4, which started on 1 April 2025, will be used for the calculation of BBCs is from 1 April 2027, two years after the start of the RCP4 period.

6.5 For the time that a lower (or higher) WACC is used than the one that applies during the RCP, the resulting shortfall (or surplus) in revenue that Transpower can recover through BBCs will be balanced by higher (or lower) residual charges so that Transpower can still recover its total allowable revenues.

The issue with the existing arrangements

6.6 The Authority's current view is that the lag in applying Transpower's updated WACC to BBCs (the WACC lag):

(a) provides some calculation certainty to Transpower

(b) but has efficiency (and distributional) consequences where there is a material change to the WACC, due to temporary under or over- recovery through the BBCs (that is then offset through the residual charge)

[38] A regulatory control period is a set block of years for which the Commerce Commission sets the revenue limits and performance standards that electricity lines businesses—such as Transpower—must follow. For example, Transpower's Regulatory Control Period 4 (RCP4) runs from 1 July 2025 to 30 June 2030 and defines what it can charge and the service levels it must deliver during that time.

[39] The Commission's cost of capital determinations can be found on the Commission's website.

[40] Specifically, clause 39(1) of the TPM states that the capital charge for a year is calculated from the opening asset value and Transpower's WACC in the preceding financial year. In practical terms, for the pricing year starting 1 April 2027 (which falls in financial year 1 July 2026 - 30 June 2027) Transpower must apply the asset's value and WACC as at 1 July 2025.

(c) those consequences will increase over time, as more of Transpower's asset costs are recovered through BBCs

(d) the lag also results in higher complexity for customers, ie, it requires more effort for them to estimate and understand their transmission charges, with two different WACCs used during the lag period.

6.7 The WACC lag therefore does not appear to be consistent with the TPM intent as it does not appropriately balance precision and practicality (TPM Guidelines clause 1b). The practical benefits of the WACC lag are limited and it adds complexity for transmission customers. The distortion from the WACC lag, which undermines the BBC price signal, will increase as the proportion of transmission charges recovered through BBCs grows.

Why the WACC lag was put in place

6.8 The rationale for the WACC lag was that BBCs should reflect the *actual* (audited) costs of investments (using depreciation and opening asset base values for the preceding financial year). Using the regulated WACC that applied for that preceding year would "ensure consistency with the capital components recovery under Transpower's individual price-quality path."[41]

6.9 The use of actual cost negates the need for wash-ups to avoid under- or over-recovery that would occur due to inevitable forecasts errors, including related to the value of newly commissioned assets. Wash-ups were considered an administrative burden that could be avoided by using actual inputs.[42] Investment to improve forecast accuracy may reduce, but would not eliminate, forecast errors, and so would not remove the administrative burden of wash ups, but would add to cost.

The consequences of the WACC lag

6.10 As the TPM has been implemented we have gained better insights on the impacts of this lagged approach. We now consider that the lag in timing of applying the updated WACC for Transpower to BBCs has few if any material administrative benefits but likely has unintended negative consequences.

6.11 The primary negative impacts relate to (a) the inefficiency from the BBCs not fully reflecting the current WACC and (b) the higher complexity for customers.

6.12 The inefficiency can be material when the change in WACC between RCPs is relatively large and will be greater when more asset costs are recovered through BBCs. During the lag period the BBC price signal, and any incentive created by that, will be either too great or too small.

6.13 The current arrangements also lead to higher transaction costs for customers in understanding and predicting transmission charges, given the complexity created by two different WACC rates applying for two out of every five years for some transmission services (particularly when the difference between the rates are large).

6.14 As the Authority has observed first hand[43], this can lead to confusion and potentially errors being made by transmission customers (or their customers) when assessing investments in generation or other business or managing their costs. We would welcome further feedback

41 TPM Proposal Reasons Paper 30 June 2021.pdf, para 13.2 page 6.6

42 TPM Proposal Reasons Paper 30 June 2021.pdf, page 6.13

43 The Authority observed this impact in the context of talking to an embedded customer about their increasing network charges and understanding the drivers for those increases, as the increase in BBCs was a material driver but did not yet reflect the increase in WACC between RCP3 and RCP4 (as that would impact from 1 April 2027).

from transmission customers on any impact (positive or negative) that the WACC lag has had on them.

6.15 We recognise that the WACC lag (and therefore any proposal to remove that lag) also has distributional impacts, as any under-recovery (or over-recovery) through BBCs will be balanced by higher (or lower) residual charges for the duration of the WACC lag period.[44] While these distributional impacts are relevant to stakeholders, they are not a primary consideration in our assessment (unless they materially affect the durability of the TPM), as explained in paragraph 6.32 below.

The negative consequences will grow over time

6.16 The efficiency (and distributional) impacts are currently relatively small because the proportion of transmission charges recovered through benefit-based charges is still relatively low. But the impact of the current approach will grow over time as more asset costs are recovered through benefit-based charges.

6.17 It is difficult to quantify the extent of the efficiency cost and distributional consequences, because there are too many hypotheticals, including how the WACC will move between RCPs, and the timing and locations of benefit-based investments over, for example, a 20- or 25-year period.

6.18 For example, if the change in WACC between RCPs is negligible, then the temporary difference in capital charges due to the lag is minimal. If the change in WACC is large, then the impact is larger also. The Authority cannot know to what extent or in what direction the WACC will change for the next RCP, let alone any subsequent RCP.

6.19 To give a sense of scale, using the book value of benefit-based assets of $2b in FY2023, a +/-1 percentage point change in the WACC implies an under (or over-) recovery through benefit-based charges of ~$20m pa for each of the two years during which the WACC lag applies, with residual charges correspondingly higher (lower) to balance revenue. The efficiency cost is some proportion of that. When the pre-tax WACC changed from 5.88% in RPC3 to 8.94% in RCP4, the impact would have been ~$61m pa for two years (in the context of benefit-based charges of $302m and residual charges of $522m in 2025/26.[45])

6.20 The chart below illustrates the impact of the proposal over time. It is based on high level projections from Transpower on the growth in the value of benefit-based investments to be recovered through benefit-based charges. It assumes the WACC alternates between some high and low WACC each RCP. There is no particular reason for assuming a regular oscillating pattern (as the direction of WACC changes long in advance cannot be known with any certainty). It is simply a possible scenario for illustration.

6.21 Assuming that the WACC for the next RCP (from 2030) reduces from its current level, the chart illustrates that revenues from benefit-based charges would adjust down 2 years faster under the proposal than under the current TPM with the two-year lag. To balance Transpower's revenue, revenue from residual charges would (temporarily) increase by the same amount. Were the WACC to increase again in future (as assumed here) then the opposite would happen.

6.22 The figure illustrates that any short-term financial impact of the current lag, and thus the efficiency cost, will get bigger over time as the amount of transmission charges recovered

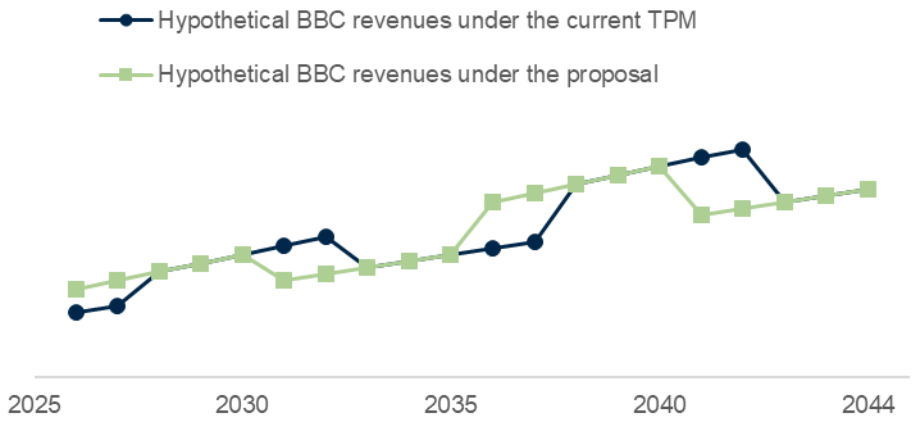
[44] Benefit based charges are paid all transmission customers benefiting from the relevant transmission investment, while residual charges are paid by all load customers (including generators to the extent they are load customers). A substantial component of the distributional "impact" will be load customers paying in aggregate the same amount but under a different charge (BBCs vs residual).

[45] See Transpower's summary of the year on year changes between pricing year 2025/26 and 2026/27.

through BBCs will grow over time. The exact efficiency cost depends on the growth in benefit-based investment and the difference in WACCs between each RCP.

6.23 Given that the efficiency costs will grow over time the Authority considers it prudent to address this issue sooner rather than later.

Figure 4 Illustrative impact on BBC revenues from removing lag in WACC



Source: Authority modelling

Proposed amendment

6.24 The Authority is proposing to amend the TPM to remove the two-year lag, so that the same WACC is used to calculate benefit-based charges as is used to calculate the overall recoverable revenue.

6.25 Removing the lag in the application of the WACC would promote efficiency by ensuring benefit-based charges better reflect the cost of transmission investments by applying the current WACC, rather than an outdated WACC for the initial two-year period at the start of each RCP.

6.26 It would also make it easier for market participants to understand and estimate the transmission charges they may face, and the timing of changes in charges. This is consistent with a robust (durable) and certain TPM that reduces risks and thus costs for consumers and businesses over the long-term.

6.27 The proposed changes involve changing aspects of clause 39 of the TPM. The main change is to change references from ‘preceding financial year’ to ‘pricing year’ which has the effect of removing the two-year lag. (Asset values and depreciation would remain as at the ‘preceding financial year’). The draft amendment to the Code is attached at Appendix C.

6.28 The proposed Code amendment would be made in time so that the WACC that the Commission would determine for RCP5 would apply to BBCs from the pricing year starting 1 April 2030.

6.29 For the avoidance of doubt, we have not considered any other options for addressing the problem identified above. As the problem itself is a timing misalignment, fixing that misalignment is the obvious and most effective way to address it.

6.30 We note that Transpower previously supported this proposed change. However, it now considers the WACC lag should be a feature of the TPM given the distributional impact it has raised. Specifically:

(a) when the WACC increased in 2025, the adjustment lag resulted in BBCs being lower for 2 years than would have been the case if the TPM had required that the WACC adjusted immediately. The residual charge was correspondingly higher for those two years

(b) in practice this temporarily kept charges for BBC-paying load (mostly) and generators lower, while load in general temporarily had higher residual charges (compared to the hypothetical situation of no lag)

(c) the distributional 'consequence' of removing the WACC lag now is that there would be no opportunity for offsetting redistributions should the WACC reduce at the next or any future RCP.

6.31 To the extent it is relevant, we cannot be sure how WACC may change in future (ie, whether the next shift in the WACC will be up or down, and by how much), and whether and to what extent that would offset the initial *implied* transfers (when compared to a situation if different TPM provisions, without a WACC lag, had applied). It is thus a weak reason at best in favour of the status quo.

6.32 In any case, the Authority's Code change proposals and decisions for the TPM must be guided by whether they promote its main statutory objective and are necessary or desirable to promote (among other things) the efficient operation of the electricity industry for the long term benefit of consumers – potential and relatively minor distributional impacts are not a primary consideration in our assessment, unless they materially affect the durability of the TPM.

6.33 The past efficiency and distributional effects are 'sunk', and in the past. We have instead evaluated whether the proposal would improve the efficiency of the electricity industry going forward, and consider the proposal would do so.

Regulatory statement

Objective of the amendment

6.34 The objective of the proposed amendment is to reduce distortions in transmission pricing and reduce the administrative burden on customers and Transpower caused by having two different WACCs in use for two out of the five years for each RCP.

Proposed amendment

6.35 The Authority proposes to amend clause 39 of the TPM to ensure that the same WACC is used to calculate BBCs as is used to calculate the overall recoverable revenue during a regulatory control period, ie, remove the WACC lag.

6.36 The drafting of the proposed amendment is contained in Appendix C.

Proposal's benefit expected to outweigh costs

6.37 Removing the lag in the application of the WACC promotes efficiency by ensuring benefit-based charges better reflect the cost of transmission investments.

6.38 It would also make it easier for market participants to understand and estimate the transmission charges they may face, and the timing of changes in charges. This is consistent

with a robust (durable) and certain TPM that reduces risks and thus costs for consumers and businesses over the long-term.

6.39 The expected cost of the amendments is the administrative cost of changing the Code (while Transpower considers the ongoing administrative costs are expected to be minimal).

6.40 Distributional effects are relevant to the extent that they can impact durability of the TPM. However, they are not a primary driver of our assessment for this proposal because:

(a) the proposal in effect removes any future distributional consequences (by removing the need to use the residual charge to balance BBC over or under-recovery during the lag)

(b) retaining the status quo would not and cannot provide any assurance of any distributional rebalancing over time. However, it would lock in identified efficiency costs.

6.41 On balance, we are not convinced that distributional issues are particularly significant for this amendment, and in any case they do not weigh heavily against it.

6.42 The Authority considers that the expected benefits of the amendment will outweigh the costs.

Proposal better than other options that have been identified

6.43 The Authority has not identified other credible means for addressing the objectives.

Proposed amendment complies with section 32(1) of the Act

6.44 The Authority considers that the proposed Code amendment is desirable to promote the efficient operation of the electricity industry, and thus complies with section 32(1) of the Act. It does so by ensuring transmission charges better reflect the cost of the transmission investments, and making it simpler to understand, estimate and administer transmission charges.

Proposed amendment complies with the intent of the 2020 TPM Guidelines

6.45 The proposed amendment is consistent with the intent of the TPM Guidelines as it seeks to ensure that benefit-based charges more accurately reflect the cost of investment, and that the basis for charges is simpler for transmission customers to understand.

Q13 Do you agree with the Authority's assessment of the consequences of the WACC lag? Please provide your reasons.

Q14 Do you agree that, because the efficiency impacts will likely grow over time, the Authority should address this WACC lag issue now? Please explain your reasons.

Q15 Do you have any comment on the drafting of the amendment to address the WACC lag in Appendix C?

7 Operational review: Batching BBC adjustment events

7.1 The Authority proposes to amend the TPM to allow BBC adjustment events during a financial year (1 July to 30 June) to be batched and processed by Transpower at a single annual date, with changes to charges for customers causing the adjustment (causing customers) to be batched and applied from the beginning of the next financial year (1 July) and other customers' charges to be adjusted at the start of the Transpower pricing year following that batching date (1 April).

7.2 This is a variant of the option proposed by Transpower (and also set out below for submitters' feedback) where adjustments take effect from the beginning of the next pricing year for all customers, removing the need for any backdating of charges for causing customers and any wash-ups for other customers.

Existing arrangements

7.3 Under the current TPM, Transpower processes and calculates adjustments as it receives notice of them. Transpower makes in-year charge adjustments and applies wash-ups at the next pricing year (as needed).

7.4 Adjustment events affect allocations for all beneficiaries. BBCs for directly affected customers are updated as soon as possible. BBCs for other customers are updated in the following pricing year with wash-ups.

7.5 Adjustments currently require sequential, event-specific modelling and wash-ups (with internal assurance) by Transpower. They also require extra effort and assurance cost for transmission customers.

Summary of Transpower's proposal

7.6 Transpower has proposed to amend the TPM to treat most adjustment events in a July to June financial year (except for an exiting customer) as occurring on a pre-defined date (eg, 30 June), and for the adjustments to take effect from the beginning of the next pricing year – removing the need for backdating of charges and washups.

7.7 Transpower's reasons for the proposal reflect practical and efficiency considerations, specifically that:

(a) "the large number of adjustments creates uncertainty, increases administrative costs, complicates pricing, reduces confidence, and affects customer investment decision making" for Transpower's customers

(b) Transpower is also impacted by this administrative burden, because of the sequential calculation of adjustments and wash-ups

(c) the volume of adjustments has been greater than Transpower anticipated at the time the TPM Guidelines were issued and is projected to increase.

7.8 Transpower states that while the proposed amendment does not reduce the volume of adjustments, it:

(a) reduces CVU and assurance burdens for customers and Transpower and it increases the efficiency with which adjustments are calculated and administered by Transpower

(b) is competitively neutral for parties causing an adjustment event

(c) could result in $5.6 million in net present value (twenty years) benefits for Transpower and customers if the proposal is implemented, according to Transpower's cost benefit analysis.

7.9 Transpower notes that batching "leads to a slight delay in commencement of charges for affected customers" and that "this temporary cost advantage is not material [vis-à-vis existing customers] and may have beneficial effects".

7.10 The proposal has widespread support from the Industry Working Group (IWG) and stakeholders who submitted through Transpower's consultation.

7.11 For detailed information please refer to Transpower's "CAR-Adjustments Events, Batching" in Appendix D.

Authority's assessment

7.12 The Authority is broadly supportive of Transpower's batching proposal because it reduces CVU for customers.

7.13 The Authority acknowledges that the current treatment of adjustment events for BBC charges has created greater than expected administrative cost for Transpower and cost and uncertainty for customers due to sequential processing and implementation, uncertain timing[46] and wash-ups. The batching proposal would reduce this administrative cost and uncertainty.

7.14 However, we are concerned that under Transpower's proposal, a customer that 'causes' the adjustment event may not need to pay any BBCs for a minimum of 9 months and up to 21 months, depending on the timing of the adjustment event.[47] Assuming adjustment events are distributed evenly over time, the average period may be 15 months.

7.15 Table 4 indicates the amounts a single 'causing customer' may avoid can be material. These amounts are drawn from Transpower's estimates of the size of the average monthly charge that could be temporarily avoided given a customer's size and grid location.[48]

7.16 Transpower projects ~30 adjustment events per year (to triple by 2031 before falling back to 30 again) meaning that, with a 15 month delay, these transfers aggregate to an average ~$8.5m per year (temporarily rising to a peak of ~$26m), though this amounts to only a small share of total charges recovered through BBCs (~3% and falling over time), and rebates foregone by other customers would be relatively small in the context of their transmission charges.

Table 4 Estimates (rounded) of BBCs a causing customer may be able to temporarily avoid

Customer type	<25 MW	All embedded	Grid connected	Average
Average monthly charge:	**$7,438**	**$13,700**	**$40,441**	**$18,793**
Time until payment starts:				
9 months (minimum)	67,000	123,000	364,000	169,000
15 months (average)	112,000	205,000	607,000	282,000
21 months (maximum)	156,000	288,000	849,000	395,000

Source: Transpower, EA calculations

46 Uncertainty is exacerbated by charges for 'causing customers' and adjustments to charges for other customers being dependent on the order in which the events are processed. Batching would resolve this.

47 Causing customers would not begin paying BBC charges until the pricing year (April) following the June batching date.

48 Average monthly charges sourced from Transpower's Code Amendment Request: Adjustment event batching, Attachment A.2-Deferral costs, Figure 3, based on 21 events.

7.17 We accept Transpower's explanation that any incentive for a causing customer to game the timing of adjustment events is likely to be small relative to the costs to them of doing so. The near-term efficiency costs are therefore likely small also.

7.18 However, we are concerned that, given these amounts, a long delay before the 'causing customer' must pay its charges may be at the threshold of affecting competitive neutrality[49] (between causing customers and other existing customers). If so, that would risk undermining the TPM's durability.[50] The Authority welcomes feedback on its concerns noting Transpower found there was support for its proposal from the IWG and submissions (see paragraph 7.10).

7.19 Given these concerns, the Authority has developed and is consulting on an alternative option that aims to retain the benefits of batching while reducing the delay in charging. This proposal builds on Transpower's proposal to batch adjustments but requires the causing customers to be charged from the batching date (1 July).

7.20 Assuming adjustments events are evenly distributed through the year, then under this alternative approach a 'causing customer' would on average not pay BBCs for six months, and up to 12 months if it entered early July – a much-reduced period than under Transpower's proposal (see Table 4).

7.21 Under this approach:

(a) causing customers would be liable for paying BBCs from 1 July (the date on which adjustment events are assumed to have happened), rather than from the following pricing year, and

(b) as these amounts are known from that date, wash-ups for other customers can be calculated by Transpower around that time and applied as single adjustments to prices for other customers in the subsequent pricing year.

7.22 Figure 5 on the next page illustrates this option.

7.23 This approach retains the need for some wash-ups. However, the Authority considers that any remaining wash-ups would be more manageable than under the current arrangements, as they would be identified at the time of batching and incorporated as single adjustments for non-causing customers in the next pricing year.[51]

7.24 In addition, and consistent with Transpower's proposal, there would be no within-year changes in charges for other (non-causing) customers. It would therefore eliminate a source of volatility, reducing uncertainty and administration costs for these transmission customers.

7.25 The Authority acknowledges that its alternative option will not eliminate administrative costs for Transpower to the same extent as under Transpower's proposal, though those costs should still be significantly lower than under the status quo. The alternative would also still eliminate a source of charge volatility and likely most of the associated administrative costs for Transpower's customers.

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49 In this context competitive neutrality means ensuring that a causing customer's delay in paying BBCs does not advantage them over other customers they compete with (who will be paying full transmission charges during that period).

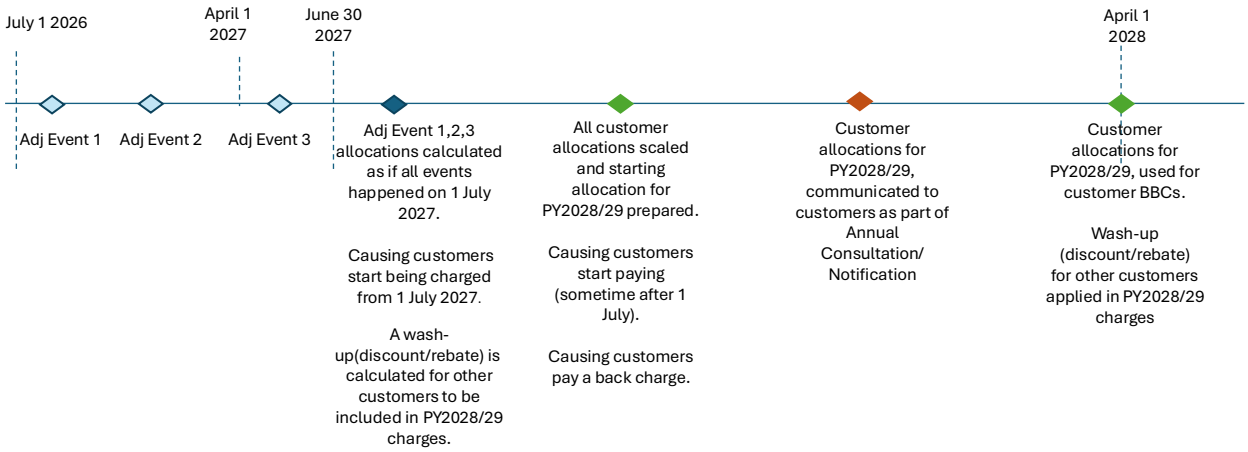
50 Transpower on page 5 of its Code Amendment Request reports that the IWG observed that a potential beneficial effect of the cost advantage to a causing customer is that it would coincide with when a new plant is financially exposed. The Authority notes that this benefit is not a significant factor in an assessment of whether the amendment would promote the Authority's statutory objective. It is also not consistent with the purpose of the TPM, which is to recover the cost of transmission services, and inconsistent with the intent of the TPM (charges should reflect the cost of providing transmission services or customers' net positive private benefits.

51 If Transpower's processes mean that it will not immediately send invoices to the causing customer in the first month(s), then it may need to back charge those causing customers to recover the outstanding amount. However, that is not a source of material or enduring volatility or uncertainty and is an internal administrative matter for Transpower, not an issue with the TPM.

7.26 In addition, the Authority's alternative is more consistent with efficient outcomes as the Authority considers it strikes a more reasonable balance between precision of charges and practical considerations than an option that may result in a customer not starting payments of BBCs for a period of up to 21 months.

7.27 On balance, the Authority prefers its alternative as it achieves administrative efficiencies and reduces CVU for transmission customers, but with a more timely allocation of charges to causing customers. The Authority considers that it strikes an appropriate balance between precision and practicality. We welcome feedback from stakeholders on either approach.

Figure 5 Timeline for batching events (Authority's proposed option)



Regulatory statement

Objective of the amendment

7.28 The objective of this amendment is to reduce CVU and associated transaction costs for Transpower's customers, and to reduce administration costs for Transpower, from BBC adjustment events.

Proposed amendment

7.29 The Authority proposes to amend the Code to allow TPM BBC adjustment events during a financial (July to June) year to be batched and processed by Transpower at a single annual date in June and to charge causing customers from 1 July of the next financial year (with other customers' charges being adjusted from the next pricing year – 1 April).

7.30 The Authority is also consulting on Transpower's initial proposal under which the same batching would occur, but all adjustments would only be charged from the beginning of the next pricing year.

7.31 The drafting of the proposed amendment, and Transpower's initial proposal are in Appendix D. For the avoidance of doubt, the Authority's drafting can be seen as comments on Transpower's proposed amendments, highlighted in D.

Proposal's benefit expected to outweigh costs

7.32 The Authority has assessed the benefits and costs of the proposed amendment and expects it to deliver a net benefit. The proposal would:

(a) reduce costs to transmission customers from having to deal with volatility in and uncertainty about benefit-based charges caused by sequential processing and implementation of adjustments, and associated wash-ups

(b) reduce cost to transmission customers from uncertainty about benefit-based charges caused by their current sensitivity to the order in which adjustment events are processed

(c) reduce administrative cost for Transpower.

7.33 The net benefits from these administrative, compliance and assurance related efficiencies will be somewhat less than those estimated by Transpower as $5.6 million net present value (as it retains some wash-up requirements) for its option.

7.34 However, these administrative benefits would still be positive under the proposal and are supplemented by the benefit of striking a more reasonable balance between precision of charges and practical considerations. That is, the approach is more consistent with the broader aim of achieving efficient outcomes, rather than just reducing administrative burden.

Proposal better than other options that have been identified

7.35 The Authority considers the proposal to be better than other options that have been identified as it would provide a better balance between precision and practicality for reasons discussed in paragraphs 7.23 to 7.27 .

Proposed amendment complies with section 32(1) of the Act

7.36 The Authority considers that the proposed amendment is desirable to promote the efficient operation of the electricity industry, and thus complies with section 32(1) of the Act. It would do so by reducing CVU of BBC charges for Transpower's customers and administration costs for Transpower and its customers.

Proposed amendment complies with the intent of the 2020 TPM Guidelines

7.37 The proposed amendment complies with the intent of the 2020 TPM Guidelines as it seeks to better balance the economic benefits and costs of precision in charging with the economic benefits and costs of practical considerations, including reduced complexity and administrative costs for Transpower and its customers.

Q16 Do you agree with the proposal to allow Transpower to batch and process BBC adjustment events at a single annual date? Please provide your reasons.

Q17 Do you agree that the causing customer should be charged from the batching date, with any adjustments for other customers to be applied in the subsequent pricing year? Please state your reasons.

Q18 Do you consider it more efficient if, instead of the proposal mentioned in Q17, adjusted charges for both the causing customers and other customers should apply from the following pricing year? Please provide your reasons.

Q19 Do you have any comment on the drafting of the amendment to enable batching of BBC adjustment events in Appendix D?

8 Operational review: Removing SSI adjustment event

8.1 The Authority proposes to amend the TPM to remove the substantial sustained increase (SSI) adjustment event. This is consistent with Transpower's proposal from phase 1 of its TPM operational review.

Existing arrangements

8.2 Under the TPM, BBC allocations are intended to be relatively fixed between designated transmission customers. BBCs are adjusted only if certain prescribed events occur. Most adjustment events are triggered by customers or plant connecting to or disconnecting from the grid, which changes how the benefits are shared.

8.3 An adjustment event is also triggered where there is a substantial sustained increase in electricity consumption or generation from existing large plant.[52] A substantial sustained increase is an increase of at least 25% since the last time the relevant customer's BBC allocations were calculated, and which is expected to persist for at least five years and is not associated with a significant plant upgrade.

Summary of Transpower's proposal

8.4 Transpower has proposed to remove substantial sustained increases as a BBC adjustment event under the TPM.

8.5 Transpower considers that the SSI adjustment event is difficult to implement and comply with in a consistent and robust way. The SSI adjustment event has not been applied in practice since the TPM came into force. The SSI adjustment event:

(a) relies on electricity use data that Transpower does not have consistent access to, particularly for large embedded plant

(b) requires Transpower to make judgements about whether changes in consumption or generation can be expected to persist for at least five years, where those judgements would need to be made at the level of individual customers or plant. This requires speculation by Transpower, and increases g administrative effort and compliance risk

(c) adds complexity and uncertainty, noting that material changes in customer circumstances are in any case generally addressed through other adjustment events (such as new connections, disconnections, and large plant connections or upgrades) or through periodic updates to allocators.

8.6 In Transpower's view, removing the SSI adjustment event would improve the robustness of the TPM and reduce complexity and the costs associated with administering and complying with the TPM.

8.7 Transpower also considered whether the SSI adjustment event could be made workable through Code requirements that compel relevant information to be provided to Transpower. Transpower considered that this would increase compliance costs for customers and other parties and would be unlikely to 'solve' the difficulties with the SSI mechanism because it would not materially improve Transpower's ability to determine whether a change in use is expected to persist for at least five years.

[52] Plant is "large" if it is grid-connected or has capacity of at least 10 MW. A plant upgrade or de-rating is large if it changes the plant's capacity by at least 10 MW.

8.8 Transpower notes that the proposal was supported by its IWG and by stakeholders who submitted through their consultation, with no opposition expressed.

8.9 For more detailed information please refer to Transpower's "CAR-Removal of SSI Adjustments" in Appendix D.

Authority's assessment

8.10 The Authority proposes to amend the TPM to remove the SSI adjustment event.

8.11 The Authority agrees with Transpower that the SSI adjustment event is not operating as intended. There are difficulties in obtaining the required data, particularly for large, embedded plant. The Authority has previously worked with Transpower to try resolve the information gaps identified and agrees that the required data t is difficult to obtain, particularly for large, embedded plant. Seeking to resolve the information gaps is only likely to be partially effective, and the issue of whether the changes to consumption or generation could be expected to persist for at least five years would remain.

8.12 Transpower provided additional information that indicates that changes in customer use that are covered by the SSI event are, in most cases, addressed through other adjustment events and provisions to update allocations under the TPM (eg, the five yearly update of simple method allocators[53]). While we recognise that there is not a perfect overlap between these provisions and the SSI adjustment event, in practice removal of the latter will not impact allocations as the adjustment event is not currently workable.

8.13 On balance, the Authority considers that the removal of an adjustment event that is not currently workable, and thus does not materially improve BBC allocations, is likely to reduce the cost for Transpower of attempting to comply with the SSI provision and manage legal review and associated regulatory risk. Noting that there are other mechanisms that partially address the changes the SSI adjustment event was meant to capture, in practice this proposed change better supports a stable and durable TPM.

Regulatory statement

Objective of the amendment

8.14 The objective of the amendment is to remove a TPM adjustment event that is not currently workable in practice, and which has not been used since the TPM came into force.

Proposed amendment

8.15 The Authority proposes to amend the Code to remove the SSI adjustment event.

8.16 The drafting of the proposed amendment is in Appendix D.

Proposal's benefit expected to outweigh costs

8.17 The Authority has assessed the benefits and costs of the proposed amendment and expects it to deliver a net benefit.

8.18 Removing the unworkable SSI adjustment event simplifies the TPM and reduces administrative and compliance costs for Transpower and customers.

8.19 The types of changes the SSI adjustment event was intended to address are partially captured through other adjustment events and periodic updates. Noting that the SSI

[53] Though those updates do not apply to BBC allocations within regional groups for existing assets, so in practice they only roll out as assets reach their end of life and are replaced/new assets are built.

adjustment event is not currently workable, removal is not expected to materially affect the allocation of BBCs.

8.20 The expected costs are minimal and limited to implementing the change. The Authority considers the benefits outweigh these costs.

Proposal better than other options that have been identified

8.21 The Authority has considered whether the SSI adjustment event could be retained and improved, including working with Transpower to test practical options. However, given the difficulty in obtaining the required data, particularly for large, embedded plant, the Authority does not consider that changes to the existing provision would make it workable in practice, ie, data gathering issue would only be partially resolved. In addition, the issue of whether the changes to consumption or generation could be expected to persist for at least five years would remain.

8.22 The Authority considers that the removal of the SSI adjustment event is therefore the most appropriate option.

Proposed amendment complies with section 32(1) of the Act

8.23 The Authority considers that the proposed amendment is desirable to promote the efficient operation of the electricity industry, and thus complies with section 32(1) of the Act. It would do so by removing a provision that is not workable in practice, so does not materially affect the allocation of BBCs.

Proposed amendment complies with the intent of the 2020 TPM Guidelines

8.24 The Authority considers that the proposed amendment is consistent with the intent of the BBC. The SSI adjustment event is not being applied in practice and therefore does not contribute to aligning charges with expected benefits. In this case, a pragmatic approach (removing the adjustment) is preferable to expending substantial effort to improve the data capture mechanisms.

8.25 Removal of the adjustment event does not materially change how benefits are reflected in charges. Other provisions within the TPM partially capture the same changes in customer use over time.

Q20 Do you agree with the proposal to remove the SSI adjustment event? Please provide your reasons.

Q21 Do you have any comments on the drafting of the amendment to remove the SSI adjustment event in Appendix D?

9 Operational review: Simple method period 1 extension

9.1 The Authority proposes to amend the TPM to extend the first simple method period so that, instead of it ending at the end of March 2028, it ends at the end of March 2029 (or 2030 if needed). This is consistent with Transpower's proposal from Workstream 1 of its TPM operational review.

9.2 This proposal would help Transpower to resolve resourcing conflicts so that it can complete Workstream 2 of its TPM operational review of its methods for benefit-based charging in a more timely manner, which the Authority supports.

9.3 However, because there is a risk that a delay in updating the simple method allocators could have material negative efficiency impacts (charges become less reflective of benefits over time), the Authority is only willing to consider an extension until the end of March 2030 at the latest.

9.4 We note that the topic of Workstream 2 is complex and a review of BBC methods could take a long time to complete (multiple years). Given these timing and efficiency risks, before deciding on this proposal, the Authority will seek further information on:

(a) whether current simple method allocators remain reasonable proxies of net private benefits

(b) whether Transpower has been able to provide suitable assurance by the end of September 2026 that it would be able to complete Workstream 2 of its operational review in time for the simple method allocators to be updated for the pricing year starting 1 April 2030.

9.5 If the Authority considers it lacks assurance on these matters, and depending on the submissions received on this proposal, the Authority may decide that Transpower should update simple method allocators as currently required.

Existing arrangements

9.6 The simple method allocates the cost of transmission investments to beneficiaries on the basis of power flows that are measured over prior five-year periods.

9.7 The first simple method period, covering the period to the end of March 2028, uses allocators that are based on an analysis of power flows covering September 2016 to August 2021.

9.8 The second simple method period would cover the period 1 April 2028 to end March 2033, using allocators based on power flows covering September 2021 to August 2026.

9.9 Transpower estimates it takes around six months of planning, calculations, analysis and assurance to derive updated simple method regions and customer allocators. This would then be followed by any changes to its pricing system and consultation on proposed pricing for the first pricing year of the second simple method period, starting 1 April 2028.

Summary of Transpower's proposal

9.10 Transpower has proposed to extend the current simple method period (the first simple method period) so that it ends in March 2029, or March 2030 if Transpower 'notifies customers at least 3 months in advance'. This further extension would be made if any proposed changes to the simple method had not yet been decided by August 2027.

9.11 Transpower's reasons for the proposal reflect efficiency and practical considerations, specifically that it:

(a) removes added complication for customers resulting from running a review of the simple method at the same time as the regular updating of simple method regions and allocators

(b) avoids the cost to Transpower of undertaking, and to customers of engaging with, a potential update of the simple method allocators shortly after having updated allocators for the second simple method period, as currently required, to implement any substantive changes to the simple method from Workstream 2 of the TPM operational review (noting that this assumes that it is preferable to bring in any changes arising out of Workstream 2 of Transpower's review earlier, rather than waiting until the next simple method period starting in 2033)

(c) avoids resource scheduling conflicts for Transpower's specialist pricing personnel so they are fully available for the operational review of the simple method

(d) has minimal efficiency impacts because (five-year averaged) grid power flows used to create simple method regions and allocators are enduring.

9.12 Transpower's IWG supports the proposal. Eight submissions on Transpower's consultation also supported the proposal, with only Meridian encouraging Transpower to stick to the current codified schedule. Its reasons were that it is important to maintain TPM charges that reflect net private benefits, and that the proposal addresses a resourcing issue, not a TPM issue.

Authority's assessment

9.13 The Authority understands Transpower's practical point: extending the first simple method period would help it resolve scheduling conflicts for the specialist personnel that should be involved in both the review of its methods for benefit-based charging and updating the simple method allocators. We also acknowledge that a delay may avoid duplicating calculation and consultation costs.

9.14 We are supportive of Transpower's effort to prepare proposals to improve the current methods for benefit-based charging. The methods are central to achieving the intended outcomes of the TPM for the long-term benefit of consumers, and the Authority would welcome proposals to improve these methods based on Transpower and the sector's experience with them over the last few years and its post implementation review findings.

9.15 At the same time, the Authority considers it important that simple method allocators remain reasonable proxies for net private benefits. A delay in updating the allocators may involve efficiency costs if power flows have changed to such an extent that current allocators risk being less than a reasonable proxy for net private benefit.

9.16 This efficiency cost could be material because new grid investments during the extended first simple method period would continue to be charged (until their end of life) based on the allocators for the first simple method period.[54] Rapid growth in total simple method charges forecast for the years ahead indicates there will be a material amount of such investments.

[54] An extension may also impact new large embedded plant during the first period. Adjustment event charges for new large embedded plant are calculated as if the plant is grid connected. This increases the host customer's simple method BBCs which are then likely passed on to the embedded plant. When simple method allocators are reviewed (ie, the delay question we are considering), they are based on net flows, which means the embedded plant would not be allocated charges directly by Transpower for future simple method investments (although the host customer may pass through attributable charges).

Indicatively, simple method charges are estimated to be $140m in 2027/28 and then increase by ~$35m (+25%) in 2028/29 and a further ~$39m (+22%) in 2029/30.

9.17 The nature and complexity of the simple method make it impractical to quantify in advance the efficiency impacts (and any temporary distributional effects)[55] of an extension of simple method period 1 – noting the forecast size of the investments in the paragraph above that the extension would capture. But a helpful indicator of whether these may be material is the extent to which power flows have changed over the relevant period.

9.18 Based on an analysis of power flows, Transpower is confident the allocators "should remain materially appropriate for an additional year(s)…" as it considers that power flows are generally enduring.[56] That would mean that any efficiency (and distributional) impacts of an extension should be minor. The Authority does not, however, consider Transpower's analysis on this point is sufficiently conclusive, noting Transpower concluded it was unable to provide further evidence in support of its conclusion without running the full simple method.[57] The Authority will undertake further analysis, and welcomes submissions, on the extent and materiality of this matter.

9.19 We will seek to balance Transpower's practical point with the risk that the efficiency impacts from delayed updates could be material. Reflecting that balance, the Authority is only willing to consider an extension of the first simple method until the end of March 2030 at the latest, as currently proposed by Transpower (extending the period from five to at the most seven years).

9.20 If the efficiency impacts of extending the first simple method period are material or the review process for the simple method is likely to take longer, then the Authority considers that Transpower should update the simple method allocators first and then focus on a review of the BBC simple (and standard) method (or suggest some other practical approach that doesn't risk the simple method update being further delayed for an unspecified period).

9.21 In drawing this boundary, the Authority acknowledges that Transpower is diligently progressing its review of the simple (and standard) method for BBCs. But the topic is complex and, depending on the scope, experience tells us that such a review could take a long time to complete. Transpower is currently completing the problem definition and project scoping stages. This process will yield Transpower better information as to the type of opportunities for improvement it wants to pursue and the likely time it will take.

9.22 The onus will be on Transpower to convince the Authority (before we decide on this proposal, and after considering all other submissions on the proposal) that the work can be completed within a timeframe that would allow simple method allocators to be updated for the 2030/31 pricing year at the latest. It will need to do so by the end of September 2026,[58] which aligns with Transpower's planning for the start of the analytical phase of the simple method update (if this were to be progressed as currently required).

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55 Noting that the Authority's Code change proposals and decisions for the TPM must be guided by whether they promote its main statutory objective, including the efficient operation of the electricity industry – distributional matters are not a primary consideration except to the extent they undermine the durability of the TPM.

56 See page 4 of Appendix_CAR_Simple_Method_Period_ExtensionApr2026.

57 In response to our initial query, Transpower compared 2016-2021 power flow data (the basis for simple method period 1 allocators) with 2018-2023 power flow data meaning that much of the data is overlapping. Transpower considered that, without running the full simple method calculation, it was not able to substantively answer our subsequent query seeking indicators of power flows or use patterns during the more relevant 2021- 2025 and a consideration of the impacts of adjustment events that have occurred since 2023.

58 For example, we would expect Transpower to have well defined problems and options by that point and be able to demonstrate a credible plan and resourcing commitment to meet the sequential timeline necessary for any resulting TPM amendments to be made, and simple method allocators updated, in time for the 2030/31 pricing year.

Regulatory statement

Objective of the amendment

9.23 The aim of the proposal is to enable Transpower to prioritise and complete a review of its methods for benefit-based charging over the updating of the simple method allocators that the TPM currently requires to be done by March 2028.

Proposed amendment

9.24 The proposal is to amend clause 60(1)(a) of the TPM to extend the current simple method period (the first simple method period) to the end of pricing year 2028 (ie, March 2029), or to the end of pricing year 2029 (March 2030 if needed).

9.25 The Authority's decision on this proposal will take account (alongside submissions and any further information on whether allocators remain reasonable proxies for net private benefits) of whether Transpower has been able to provide suitable assurances that it would be able to complete phase 2 of its operational review in time for the simple method allocators to be updated in time for the pricing year starting 1 April 2030.

Proposal's benefit expected to outweigh costs

9.26 The proposal would avoid the administrative costs from potentially duplicating change processes for simple method allocators (once to update them as required, and then a further one a year or two later after to implement any substantive changes to the simple method stemming from the review (assuming that these changes are made earlier, rather than waiting until 2033).

9.27 The proposal may bring forward by one year the efficiency gains that may stem from Transpower's operational review of benefit-based charging methods (which would otherwise be delayed).

9.28 The potential for such efficiency gains is currently unknown but could include those stemming from a better identification of customers' net private benefits of investments, lower administrative costs for Transpower, as well as benefits to transmissions customers from reduced complexity, volatility and uncertainty.

9.29 There is a risk that these benefits may be offset by the potential for efficiency losses, if there have been material changes in power flows, such that current allocators are no longer a reasonable proxy for customers' net private benefits of grid investments.

9.30 While we understand Transpower's reasoning that an extension of the simple method period by one year (or two, as seems more likely) should not change the operational or investment behaviours of customers or wider participants (and so have no economic cost)[59], we note this may understate the risk, as any misallocations are baked in for the remainder of the life of simple method investments once made, and there are a material amount of such investments that are forecast to be made during these two years.

9.31 As there is uncertainty over the degree to which power flows have been enduring, it is prudent to assume that there is some economic cost. Even so, as effective benefit-based charging is central to the TPM, the Authority considers the benefits of prioritising improvements to the BBC methods likely outweigh the costs of extending the simple method period (by no more than two years).

[59] Page 9 of Appendix_CAR_Simple_Method_Period_ExtensionApr2026.

Proposal better than other options that have been identified

9.32 The Authority has not identified any options other than the status quo and the proposed extension have been identified.

9.33 Given the specialist nature of the work, we did not consider it would be viable for Transpower to simply hire more personnel (or engage expert consultants) to resource both projects in parallel in the relevant timeframe as the upskilling effort and time required would be too high.

Proposed amendment complies with section 32(1) of the Act

9.34 The proposal would promote the efficient operation of the electricity industry by reducing administration costs and bringing forward efficiency gains that may stem from the improvement in benefit-based charging methods.

Proposed amendment complies with the intent of the 2020 TPM Guidelines

9.35 The proposed amendment complies with the intent of the TPM Guidelines as it balances the economic costs and benefits of precision of allocators with the economic costs and benefits of practical considerations, including the cost of developing, administering and complying with the TPM. By supporting the timely operational review of BBCs, the proposal would also promotes ensuring that charges are set in a way that reflect the share of transmission customers' net private benefits.

Q22 Do you agree with the proposal to extend the first simple method for up to two years (to end 31 March 2029 or 31 March 2030 if needed), so that Transpower can complete its operational review of its methods for benefit-based charging in a more timely manner? Please provide your reasons.

Q23 Has the Authority correctly identified the risk that a delay may involve efficiency costs as historical allocators risk being less than a reasonable proxy for net private benefits? Please provide your reasons.

Q24 Do you agree that, if Transpower cannot convince the Authority that the review can be completed within a timeframe that would allow simple method allocators to be updated for the 2030/31 pricing year at the latest, then Transpower should first update the simple method allocators as currently required? Please provide your reasons.

Q25 Do you have any comments on the drafting of the amendment to extend the first simple method period in Appendix D?

10 Operational review: Drafting refinements

10.1 The Authority intends to amend the Code to implement drafting refinements and tidy-ups to the TPM, including removing redundant and outdated provisions and making minor drafting improvements. This is consistent with Transpower's proposal from phase 1 of its TPM operational review.

Summary of Transpower's proposal

10.2 Transpower's proposal seeks to tidy up the drafting of the TPM by removing provisions that are no longer relevant, correcting typographical errors and making minor drafting improvements.

10.3 These include provisions relating to historical concepts (such as pre commencement events) that are no longer required and may create confusion for stakeholders interpreting the TPM.

10.4 The detailed drafting changes are set out in the Appendix D: "CAR-Legal Drafting and Tidy-Ups, April 2026" and "Proposed drafting changes- Legal Drafting Tidy-ups."

Authority's assessment

10.5 The Authority considers that the proposed amendments are technical and non-controversial and do not change the substantive operation of the TPM. The proposed amendments simplify the drafting of the Code and how it is applied.

10.6 The proposed amendments have also already been adequately consulted on by Transpower and received widespread support from submitters (and the IWG). The Authority therefore:

(a) is publicising a draft of the proposed amendment, as required by s39(1)(a) of the Act

(b) has not prepared a regulatory statement and is not consulting on the proposed amendment and the regulatory statement – refer s39(1)(b), 39(1)(c) and 39(3) of the Act.

Q26 The Authority is not consulting on technical and non-controversial drafting tidy-ups of the TPM, however, do you have any feedback on any potential re-drafting errors or additional suggestions?

11 Fixing shared connection asset allocators

11.1 The Authority is seeking initial feedback on a possible future amendment to the TPM to change the allocation of connection costs between customers who share connection assets from a variable to a fixed share of costs. If we were to propose this change, the fixed shares would use the connection customer allocators that apply in the current pricing year (2026).

11.2 This would stop the current annual recalculation of customer allocators at shared connection assets, thereby:

- reducing administration cost
- reducing uncertainty about connection cost
- eliminating inefficient incentives for connected parties to alter their offtake or injection patterns to shift charges to other connected customers.

11.3 We seek early feedback on this possible approach. We are also interested in any views on consequential questions, eg, how to set fixed allocators for new customers at a connection asset that is or would now be shared.

Existing arrangements

11.4 The costs of a connection asset, where these are not covered through a Transpower Works Agreement (TWA)[60], are recovered from connection customers through TPM connection charges.

11.5 Where multiple customers share a connection, connection charges are apportioned based on the greater of anytime maximum demand (AMDC) or injection (AMIC)[61] for each customer (together defined in the TPM as AMDIC) as a share of the sum of those maxima for all customers at that location.[62] These shares are reset annually.

Potential issues with existing arrangements

11.6 The 2020 TPM Guidelines mostly retained the 2006 Guidelines on connection charges, as they were largely consistent with the principles of efficient transmission charging. As such, the current TPM retained many of the connection charge provisions of the previous TPM.

11.7 The Authority has however since identified that one aspect of connection charges – the annual recalculation of allocators at a shared connection – is not well aligned with the approach set out in the 2020 TPM Guidelines.

11.8 In brief, the current annual recalculation of customer allocators at shared connection locations may result in:

- volatility in shared connection allocators and thus year-on-year uncertainty about connection charges
- administrative cost associated with measurement and annual recalculation of shares

60 TWAs are contractual and reflect funding commitments to build new assets/upgrades. They sit outside the regulated pricing framework (ie, the TPM). From commissioning, operation and maintenance costs of a connection asset are recovered as connection charges. Capital costs are recovered through connection charges once the TWA period ends.

61 AMDC and AMIC are the average of the 12 highest grid offtake or injection quantities for the customer at the connection location during the measurement period, multiplied by 2 to convert to average supply.

62 AMDC and AMIC for pricing year n are measured in year n-2. For example, shares for pricing year 2026/27 are based on AMDC and AMIC measured during 1 Sep 2024 to 31 August 2025.

- inefficient incentives for parties to alter their offtake or injection patterns to reduce their share of connection charges, shifting these to other connected customers
- customers facing higher charges due to temporary or atypical increases in AMD or AMI that are not reflective of their ongoing capacity requirements.

Extent of current problem

11.9 There are two concerns driving the Authority's interest in shared connection allocators.

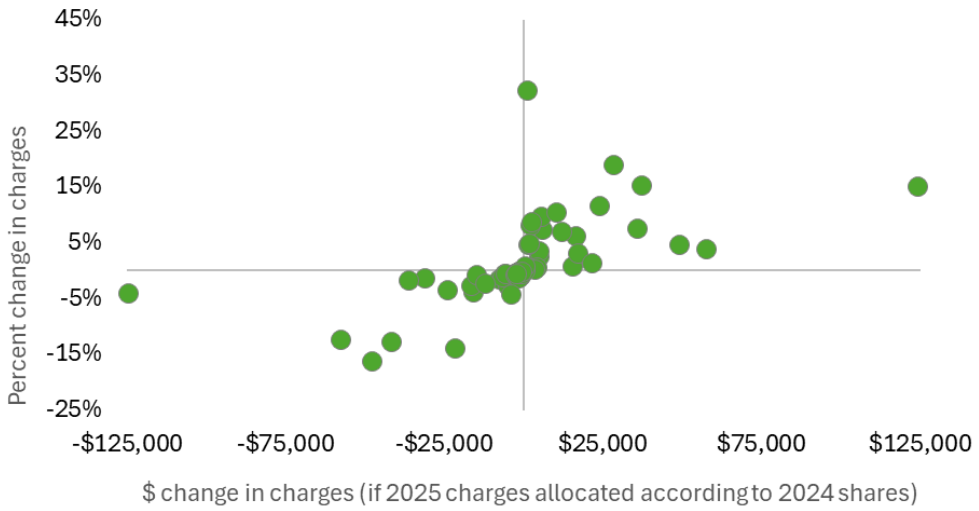
11.10 First, year-on-year volatility of charges caused by year-on-year changes in shares of AMDIC, which may contribute to customers' CVU concerns. Where large and small customers share a connection asset even a small change in AMDIC by a large customer can lead to disproportionate changes in annual charges for smaller customers.

11.11 This is illustrated in the chart below, which shows the impact on customers' 2025 connection charges if the shares that applied in 2024 had been used in 2025 also. This is for 30 shared connections (out of 169 connection locations), leaving out shared connection points where a customer recently joined or exited.

11.12 The percentage and dollar changes in annual charges due to the change in shares cluster around 0, and average around +/- 1.4% or +/-$15,000. Increases in charges for customers are offset by decreases for other customers at each location.

11.13 However, changes in charges can be materially larger. For illustration, the largest change shown relates to changes in shares for parties connected at Glenbrook. In 2024 NZ Steel's share at ~76% was slightly lower than the prior and subsequent year (~79%). If that share had also applied in 2025, New Zealand (NZ) Steel's connection charges would have been $124k (or 4%) lower. But charges would have been 15 % (or $124k) higher for the other (smaller) customer sharing that connection asset (Counties Power).

Figure 6 An indicator of volatility in shares and charges due to change in shares



11.14 Second, we continue to seek to reduce potential cost shifting incentives in the TPM. To be clear, the Authority has not observed evidence of customers currently acting on cost-shifting incentives related to shared connection assets. Connection charge data from the last four years indicates customers' shares of connection charges at shared locations vary year-to-year but appear to be relatively stable over time.

11.15 This current lack of evidence may reflect the relatively small impact on connection charges that changing use could have, effectively suggesting that it's not worth the effort. However, in our view it is plausible that technology may in the future enable targeted changes in use at key times, making cost shifting a simpler and lower effort option, ie, changing the 'effort calculus'.

11.16 Addressing the issue now would therefore protect against the potential for greater volatility and cost shifting issues in future, although the immediate benefit of addressing the issue would likely be marginal. Feedback from Transpower has indicated that to date it has not received material negative feedback about the current approach from customers. And when we tested this question with Transpower's IWG they were not convinced that there was currently a problem worth fixing with shared connection asset allocators. The Authority seeks further input on whether to address the annual recalculation now to protect against the potential for greater volatility and cost shifting issues in future.

Existing approach is inconsistent with efficient charging

11.17 The nature of connection assets indicates that efficient charges would be based on fixed cost shares. This is because, once built, the capacity of connection assets is fixed and the marginal costs of using the asset are minimal, so adjusting use of the asset does not change economic costs. Therefore, efficient cost recovery is expected to be through fixed charges.

11.18 There is therefore no efficiency reason we are aware of for Transpower to reallocate connection costs annually between customers sharing the connection asset using what is in effect a peak charge.

11.19 Consistent with this, fixing charges is, in our view, more likely to be an arrangement that would be observed in a workably competitive market. It is unlikely that in a workably competitive market customer A sharing a connection asset with customer B would agree to a contract where its share of essentially fixed costs (and thus its charges) would be subject to changes in consumption or generation activity by customer B, over which customer A does not have control. It is more likely that shares would be based on the maximum capacity each customer would need over time.

Possible future amendment for feedback

Fixing shares for current customers at a shared connection

11.20 The Authority is considering whether it would be more efficient if customers at a shared connection asset were allocated fixed cost shares, rather than recalculating shares annually. This would solve the potential problems identified in paragraph 11.8.

11.21 If the Authority were to propose such an amendment to the TPM, a simple and effective approach could be to use the shares that applied in the 2026 pricing year. Because these shares have already been determined, selecting that year would avoid the risk that customers take inefficient actions now to try to permanently reduce their share of costs.

11.22 We appreciate that using a specific year gives rise to a risk that some customers may end up paying a disproportionate charge permanently when the allocators are fixed if 2026 was an outlier year for them (in terms of their AMDIC). However, in practice this risk seems small – a comparison of 2026 shares to those in the three years prior does not indicate any uncharacteristic allocations.

11.23 Possible mitigations to that risk include using an average of shares observed over the past four years or giving Transpower an enduring discretion to adjust disproportionate shares.

However, these options have disadvantages also, including that they would add a source of complexity and/or uncertainty.

Consequential changes – adjusting for material changes in AMDIC, or upgrades; charges for new customers

11.24 The use of fixed shares of costs at a shared connection asset would also raise questions about whether and how those shares may need to be adjusted. To provide a fuller picture for feedback, we briefly outline some of the current thinking in three scenarios below.

Material and enduring changes in a customer's AMDIC at a shared connection location

11.25 As connection costs are fixed there are no efficiency reasons to adjust shares even for material changes. Not adjusting would also keep charges more predictable, avoid complexity, and avoid the information issues discussed in Chapter 8.

Upgrade in capacity at a shared connection

11.26 The TPM may need to clarify that the fixed allocators would be revised in case of an upgrade (eg due to expansion by customers at the shared connection), so that allocations for the upgrade are on a cost-reflective causer-pays basis.

A new customer connects at a shared connection location (or any connection location which becomes shared when the new customer connects)

11.27 Under the current TPM, when a new customer joins Transpower initially estimates the new customer's AMDC or AMIC.[63] For a shared connection asset this would be the basis of the new customer's share of connection cost, until Transpower is able to measure the new customer's actual AMDIC.[64]

11.28 If the TPM were amended so that cost shares are fixed using this first actual measurement, it may create a risk that this is not a reasonable measure of enduring use, or that a new customer manages its use of electricity in that first period of measurement to reduce its enduring share of cost.

11.29 To address that risk, one option would be to fix a customer's ongoing share based on Transpower's initial estimate. This is simple but is not consistent with how existing customer's shares were set (which some may consider problematic). Another option might be to base the enduring fixed share on a, say, four-year average of actual measured AMDIC, though that adds complexity and transaction costs and results in the initial estimate being used for a substantial period of time (which may weaken the case for a subsequent adjustment in shares to reflect actuals).

63 Taking into account the type and capacity of the connecting customer's assets and AMDC or AMIC for any other customers with assets of the same or a similar type.

64 In the 12-month capacity measurement period starting in September in the year two years prior to the pricing year. (An allocator for the pricing year April 2027 to March 2028 would be based on AMDIC measured September 2025 – August 2026).

Q27 Has the Authority correctly identified a potential issue with the current approach to determining customers' shares of cost at shared connection assets?

Q28 Do you agree with the Authority's assessment that, while the immediate benefit of the proposal is likely marginal, it is nonetheless useful to address this issue to remove volatility in shares (and thus charges) and to protect against issues becoming bigger in future?

Q29 Do you have any initial feedback on the Authority's current thinking to inform a possible amendment to the TPM (to be developed and consulted on in future) to:

29a Fix cost shares at shared connection assets at those that applied in the 2026 pricing year?

29b Fix the shares for a new customer at a shared connection asset based on Transpower's estimate given the capacity and type of the customer's plant, or some other approach?

29c Not make any provision for those fixed shares to adjust even when there is a material and enduring change in the AMDIC of one of the customers sharing the connection asset?

29d Add a clause to clarify that shares will be recalculated when a change in AMDIC by one or more customers at the shared connection asset necessitates an upgrade?

12 Emerging connection charge and FMD issues

12.1 In its Workstream 1 Proposal Document, Transpower identified three potential policy issues on connection charges and first-mover disadvantage and said it would work with the Authority on next steps.[65]

12.2 We set out our views on two of the issues below. Chapter 5 addresses the third issue related to anticipatory capacity for interconnection assets.

Disconnection from shared connection location

12.3 After a recent disconnection at a shared connection location, Transpower identified a potential issue: when one customer disconnects[66], its share of connection charges shifts to the remaining customer(s), potentially causing sharp and unexpected increases in their connection charges unrelated to any change by them.

12.4 This re-allocation is conceptually consistent with the TPM's cost-reflective design. Also, the reallocation mechanism is not new – it was not part of the previous reform process. And the TPM's stand-alone prudent discount policy protects customers from inefficiently high transmission charges, by capping charges (if the policy applies) at the efficient stand-alone cost of the transmission services they receive.

12.5 Transpower is assessing whether the prudent discount mechanism adequately addresses such a situation for one of its customers who faces a large increase in charges after a large customer with whom it shared a connection asset disconnected. For now, Transpower and the Authority consider it best to wait for the outcome of that assessment before deciding whether the TPM may need to be amended, and, if so, how.

First mover disadvantage type 1 issues

12.6 The new TPM introduced protections for a first customer that funds a new or upgraded connection asset from a first-mover risk. Under the funded asset component (FAC), later connecting customers can be charged a share of the cost (based on the remaining economic life of the asset) which is then rebated to the first customer.

12.7 A concern has been raised that this may not fully address first mover disadvantage where later customers do not connect or connect much later than expected. This leaves the first mover exposed to financial risk, meaning they may not recover a share of the initial investment as expected.

12.8 Following further consideration, the Authority considers this risk should not be addressed through the TPM. Transpower shares this view. The FAC mechanism appears to work as intended. The decision to connect first and the size of the connection asset are choices for the first mover. If they enter into an agreement that reflects these choices but the expected later connections are delayed or do not eventuate, then this is a risk for the first mover to manage, and not a TPM issue. The risk is better dealt with through commercial arrangements between parties.[67] We do not consider that changes to the TPM are required in response to this issue.

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65 See Transpower's 2026 Proposal Document pages 19-22. Transpower had previous raised these points, at a high level, with the IWG and in its March 2026 TPM operational review Workstream 1 consultation.

66 Or has a significant load reduction, noting that the proposal set out earlier in this paper to fix shared connection allocators would effectively respond to any concerns about the impact of another customer reducing load.

67 For example, see paragraph B.31 in the 2019 TPM Issues paper on this point.

12.9 Stakeholders have also raised concerns that the FAC may not work as intended for connection assets that benefit embedded large plants. For example, if a generator funds an upgrade at a grid exit point already shared with a distributor, future embedded generators (not Transpower customers) may benefit without paying the FAC.

12.10 The Authority is currently considering reforms to the Distributed Generation Pricing Principles and considers this to be a more appropriate forum to consider this issue in the first instance.[68] We are open to revisiting the issue through the TPM later if needed.

Q30 The Authority is not consulting on proposals to address these emerging issues, but do you have any feedback or further information on these emerging issues and how these are being progressed?

[68] Refer to: Distributed generation pricing principles reform | Our projects | Electricity Authority

Appendix A Submission form due 24 July 2026

A.1 A Word version of the submission form is included with the consultation documents.

Transmission Pricing Methodology amendments 2026

Please email your submission to networkpricing@ea.govt.nz by 5pm, 24 July 2026.

#	Question	Response
Chapter 3: Context and approach		
1	Do you agree with the assessment approach and criteria set out in this chapter? Please explain your reasons.	
2	Do you consider an alternative approach or assessment criteria should be used? If so, please describe these and explain why these would be better.	
Chapter 4: BBC simple method treatment of battery storage		
3	Do you agree that offtake by battery storage should be exempt from the Demand Factor? Please explain your reasons.	
4	Do you prefer any of the alternative options discussed for the treatment of battery storage under the simple method? Please explain your reasons.	
5	Do you agree that the proposed amendment for battery storage offtake should be made ahead of Transpower's next phase of its operational review, when it will review the simple method? Please explain your reasons.	
6	Do you have any comment on the drafting of the amendment to the treatment of battery storage in Appendix C?	
Chapter 6: Applying updated WACC without a lag		
13	Do you agree with the Authority's assessment of the consequences of the WACC lag? Please provide your reasons.	
14	Do you agree that, because the efficiency impacts will	

		likely grow over time, the Authority should address this WACC lag issue now? Please explain your reasons.	
15		Do you have any comment on the drafting of the amendment to address the WACC lag in Appendix C?	
Chapter 7: Batching BBC adjustment events			
16		Do you agree with the proposal to allow Transpower to batch and process BBC adjustment events at a single annual date? Please provide your reasons.	
17		Do you agree that the causing customer should be charged from the batching date, with any adjustments for other customers to be applied in the subsequent pricing year? Please state your reasons.	
18		Do you consider it more efficient if, instead of the proposal mentioned in Q17, adjusted charges for both the causing customers and other customers should apply from the following pricing year? Please provide your reasons.	
19		Do you have any comment on the drafting of the amendment to enable batching of BBC adjustment events in Appendix D?	
Chapter 8: Removing SSI adjustment event			
20		Do you agree with the proposal to remove the SSI adjustment event? Please provide your reasons.	
21		Do you have any comments on the drafting of the amendment to remove the SSI adjustment event in Appendix D?	
Chapter 9: Simple method period 1 extension			
22		Do you agree with the proposal to extend the first simple method for up to two years (to end 31 March 2029 or 31 March 2030 if needed), so that Transpower can complete its operational	

		review of its methods for benefit-based charging in a more timely manner? Please provide your reasons.	
23		Has the Authority correctly identified the risk that a delay may involve efficiency costs as historical allocators risk being less than a reasonable proxy for net private benefits? Please provide your reasons.	
24		Do you agree that, if Transpower cannot convince the Authority that the review can be completed within a timeframe that would allow simple method allocators to be updated for the 2030/31 pricing year at the latest, then Transpower should first update the simple method allocators as currently required? Please provide your reasons.	
25		Do you have any comments on the drafting of the amendment to extend the first simple method period in Appendix D?	
Chapter 10: Drafting refinements			
26		The Authority is not consulting on technical and non-controversial drafting tidy-ups of the TPM, however, do you have any feedback on any potential re-drafting errors or additional suggestions?	
Chapter 11: Fixing shard connection asset allocators			
27		Has the Authority correctly identified a potential issue with the current approach to determining customers' shares of cost at shared connection assets?	
28		Do you agree with the Authority's assessment that, while the immediate benefit of the proposal is likely marginal, it is nonetheless useful to address this issue to remove volatility in shares (and thus charges) and to protect against issues becoming bigger in future?	

29		Do you have any initial feedback on the Authority's current thinking to inform a possible amendment to the TPM (to be developed and consulted on in future) to: **a**: Fix cost shares at shared connection assets at those that applied in the 2026 pricing year? **b**: Fix the shares for a new customer at a shared connection asset based on Transpower's estimate given the capacity and type of the customer's plant, or some other approach? **c**: Not make any provision for those fixed shares to adjust even when there is a material and enduring change in the AMDIC of one of the customers sharing the connection asset? **d**: Add a clause to clarify that shares will be recalculated when a change in AMDIC by one or more customers at the shared connection asset necessitates an upgrade?	
Chapter 12: Emerging connection charge and FMD issues			
30		The Authority is not consulting on proposals to address these emerging issues, but do you have any feedback or further information on these emerging issues and how these are being progressed?	

Appendix B Submission form due 7 August 2026

Transmission Pricing Methodology amendments 2026

B.1 Please email your submission to networkpricing@ea.govt.nz by 5pm, 7 August 2026.

Chapter 5: Anticipatory capacity		
#	**Question**	**Response**
7	Has the Authority correctly described the nature and root cause of the cost-allocation issues for anticipatory connection assets? Please provide your reasons.	
8	Do you agree with the proposal to require the use of the standard method to allocate the 50% share of capital cost of anticipatory connection assets that is to be recovered through benefit-based charges? Please give your reasons.	
9	Do you agree with the proposal that the requirement to use the standard method for allocating the cost of anticipatory capacity should progress ahead of Transpower's operational review of the benefit-based charging methods? Please state your reasons.	
10	Do you agree that the cost of anticipatory interconnection assets should be met by beneficiaries through the normal BBC allocation approach? Please explain your reasons.	
11	Can you identify better options than those proposed by the Authority to allocate the cost of anticipatory assets? Why would your option be better?	
12	Do you have any comment on the drafting of the amendment to the treatment of anticipatory connection assets in Appendix C?	

Appendix C Proposed Code amendments

BBC simple method treatment of battery storage

Proposed amendment

61 Individual NPB

(1) A **customer's individual NPB** for a **BBI** in an **investment region** (NPB) is calculated as follows:

$$NPB = \sum_{g} \left(\frac{RNPB_g \times SMF_g}{F} \right)$$

where

$RNPB_g$ is **regional NPB** for **regional customer group** g, where **regional customer group** g is a **regional customer group** for the **BBI**—

(a) that has positive **regional NPB** in respect of the **investment region**; and

(b) of which the **customer** is a member

SMF_g is the **customer's simple method factor** for **regional customer group** g

F is:

(a) the **demand factor**, where that a **customer** is a member of a **regional demand group** due to its **offtake** for **battery storage**; and

(b) otherwise 1,

Anticipatory Capacity

Proposed amendment

27 Anticipatory BBIs

(1) The **benefit-based charges** for **anticipatory BBIs** recover the part of the capital cost of **anticipatory connection assets** that is not recovered through the asset component of **connection charges**, specifically half of that capital cost.

(2) For each **anticipatory connection asset** for a **pricing year** there is deemed to be a **commissioned BBI** (an **anticipatory BBI**) for the **pricing year** (only for the purpose of recovering half of the capital cost of the **anticipatory connection asset**)—

(a) that comprises the **anticipatory connection asset**; and

(b) that has a **covered cost** for the **pricing year** (COVC) calculated as follows:

$$COVC = ((r \times V_{anticipatory}) + D_{anticipatory}) \times 0.5$$

where

r	is **Transpower's PQ WACC** (pre-tax) for the **pricing year**
$V_{anticipatory}$	is the part of the total **closing RAB** value for the preceding **financial year** attributable to the **anticipatory connection asset**, as determined by **Transpower**
$D_{anticipatory}$	is the part of total **depreciation** during the preceding **financial year**, excluding **accelerated depreciation**, attributable to the **anticipatory connection asset**, as determined by **Transpower**; and

(c) for which the **start pricing year** is the **pricing year**; and

(d) for which a customer's **individual NPB** is calculated under the ~~**simple method**~~ **standard method**, ~~subject to the modifications in subclause (3)~~ and even if the **anticipatory BBI**'s deemed **covered cost** for the **pricing year** under paragraph (b) is less~~more~~ than the base capex threshold as defined in the **Transpower Capex IM**.

~~(3) The modifications referred to in paragraph 2(d) are as follows:~~

~~(a) If **Transpower** determines the **anticipatory BBI** is primarily to allow for a future increase in **offtake**, the **anticipatory BBI's regional customer groups** are limited to **regional supply groups**:~~

~~(b) If **Transpower** determines the **anticipatory BBI** is primarily to allow for a future increase in **injection**, the **anticipatory BBI's regional customer groups** are limited to **regional demand groups**.~~

Applying updated WACC without a lag

Proposed amendment

39 Covered Cost

(1) A **BBI's covered cost** for a **pricing year** (CC) is calculated as follows:

$$CC = \sum_{a} (D_a + C_a + T_a) + AO$$

where

D_a is **depreciation** of asset a for the preceding **financial year**, where asset a is an asset comprised in the **BBI**, excluding **accelerated depreciation**

C_a is the **capital charge** for asset a and the ~~preceding financial~~ **pricing year** calculated under subclause (2)

T_a is the sum of—

(a) **Transpower's** depreciation tax loss (positive value) or gain (negative value) for asset a and the ~~preceding financial~~ **pricing year** calculated under subclause (3); and

(b) income tax on the **capital charge** for asset a and the ~~preceding financial~~ **pricing year** calculated under subclause (5)

AO is the attributed opex component for the **BBI** and **pricing year** calculated under subclause 40(1).

(2) The **capital charge** for an asset and ~~financial~~ **pricing year** (C) is calculated—

(a) if the asset had an **opening RAB value** for the preceding **financial year**, as follows:

$$C = r \times V$$

where

r is **Transpower's PQ WACC** (vanilla) at the start of the ~~financial~~ **pricing year**

V is, subject to subclause 7, the **opening RAB value** for the asset and preceding **financial year**; or

(b) if the asset was commissioned during the preceding **financial year**,, as follows:

$$C = V \times \frac{r \times (12.5 - m)}{12}$$

where

V	is, subject to subclause (7), the asset's **value of commissioned asset**
r	is **Transpower's PQ WACC** (vanilla) at the start of the ~~**financial**~~ **pricing year**
m	is the month of the preceding **financial year** during which the asset was **commissioned** (for example, m = 3 for September).

(3) **Transpower's** depreciation tax loss or gain for an asset and ~~**financial**~~ **pricing year** (T_{dep}) is calculated as follows:

$$T_{dep} = \frac{r \times (AD - TD - I)}{1 - r}$$

where

r	is the corporate tax rate, as defined in the **Transpower IMs**, at the start of the ~~**financial**~~ **pricing year**
AD	is **depreciation** of the asset during the preceding **financial year**, excluding **accelerated depreciation**
TD	is tax depreciation of the asset during the preceding **financial year**, excluding **accelerated depreciation**
I	is notional interest for the asset and ~~**financial**~~ **pricing year** calculated under subclause (4).

(4) Notional interest for an asset and ~~**financial**~~ **pricing year** (I) is calculated as follows:

$$I = V \times L \times CD$$

where

V	is, subject to subclause (7), the **opening RAB value** for the asset and preceding **financial year**
L	is leverage, as defined in the **Transpower IMs**, at the start of the ~~**financial**~~ **pricing year**
CD	is the estimated cost of debt used under the **Transpower IMs** to calculate **Transpower's PQ WACC** (vanilla) applicable at the start of the ~~**financial**~~ **pricing year**.

(5) Income tax on the **capital charge** for an asset and ~~**financial**~~ **pricing year** (T_{inc}) is calculated as follows:

$$T_{inc} = \frac{r \times C}{1 - r}$$

where

r	is the corporate tax rate, as defined in the **Transpower IMs**, at the start of the ~~**financial**~~ **pricing year**
C	is the **capital charge** for the asset and ~~**financial**~~ **pricing year** calculated under subclause (2).

Appendix D Transpower's Code amendment requests

D.1 Transpower's Code Amendment Requests and supporting documents accompany this consultation paper (listed below), and are also available at Transpower's TPM operational review webpages:

Code Amendment Request Adjustment Event Batching

D.2 Appendix D - CAR - Adjustment Events, Batching

D.3 Appendix D - Attachment A.3

D.4 Appendix D - Proposed drafting changes - Adjustment Events, Batching

Code Amendment Request Removal of SSI Adjustment Events

D.5 Appendix D - CAR - Removal of SSI Adjustment Events

D.6 Appendix D- Proposed drafting changes - Removal of SSI Adjustment Events

Code Amendment Request Simple Method Period Extension

D.7 Appendix D- CAR - Simple Method Period Extension

D.8 Attachment C.1 - Analysis of power flows in simple method regions.pdf

D.9 Appendix D - Proposed drafting changes - Simple Method Period Extension

Code Amendment Request Legal Drafting Tidy-Ups

D.10 Appendix D - CAR - Legal Drafting Tidy-Ups

D.11 Appendix D Proposed drafting changes - Legal Drafting Tidy-Ups