Transmission pricing methodology amendments 2026

Decision paper

23/11/2026

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (Authority) has decided to make five targeted amendments to the Transmission Pricing Methodology (TPM), along with some minor drafting improvements.

The amendments will better align transmission charges with benefits, strengthen investment signals, reduce administrative costs, and support a stable and predictable transmission pricing framework.

This paper sets out the Authority's decisions on these amendments and on one proposed amendment we decided not to make.

Transmission pricing framework supports efficient investment and affordable electricity in the long term

Transmission makes up around 8% of consumers' electricity bills and plays an important role in supporting efficient investment in, and operation of, the electricity system. The way transmission costs are allocated influences where generation and demand are developed, how the transmission network is used, and where investments are made.

Having the right transmission pricing settings helps to get the right network and generation assets built in the right places and at the right time. This supports electrification and decarbonisation and helps deliver reliable electricity at the lowest long-term cost for New Zealand consumers.

The TPM determines how transmission costs are shared among electricity users. It is based on two core principles:

- charges 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.

The Authority considers these principles and the overall TPM framework remain sound and support the electricity industry's ongoing evolution. However, since the current TPM was implemented in 2023, the Authority and Transpower have identified opportunities to refine the TPM to improve its operation and efficiency within its overall framework.

Amendments to better align charges with benefits and reduce administrative costs

The decisions on targeted amendments to the TPM are summarised in **Error! Reference source not found.** and follow consultation on six proposals in July 2026. These amendments are part of the Authority's wider network pricing reform programme, including distribution and distributed generation pricing principles. Together, this work helps ensure the overall pricing framework sends coherent and durable signals for network use and investment across the electricity system.

Following consultation, including on regulatory statements for each proposal, the Authority considers that the Code amendments – as detailed in this paper and the appendices – are necessary or desirable to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

Table 1 Decisions on targeted amendments to the TPM

1. Refine simple method allocation for battery storage
This change involves exempting large battery storage from the demand factor that is applied to simple-method offtake allocations. This is to treat batteries consistently with other supply technologies and reduce the risk that large batteries attract disproportionately high transmission charges. The Authority considers this change will be for the long-term benefit of consumers by supporting efficient investment in grid-scale battery storage and lowering system costs.
2. Applying current WACC to calculation of benefit-based charges
This amendment removes the two-year lag between the weighted average cost of capital (WACC) used by the Commerce Commission to set Transpower's maximum allowable revenue and its use in calculating benefit-based charges under the TPM. The Authority considers this will be for the long-term benefit of consumers by making benefit-based charges more cost-reflective and reducing the complexity and administrative cost that customers and Transpower incur when different WACCs apply to different charges at the same time.
3. Updated approach to allocate cost of anticipatory capacity for connection assets
This change requires Transpower to use the TPM's standard method, instead of the simple method, to allocate 50% of the capital cost of that part of a connection asset that is anticipatory (with the other 50% shared among all connecting customers). This change will improve the allocation of charges and ensure the right parties have incentives to scrutinise proposed investments in anticipatory connection assets. The Authority considers this will be for the long-term benefit of consumers by supporting more efficient transmission investment and lowering system costs. The Authority has decided to progress this amendment now (rather than early in 2027 as we indicated was our plan), because we consider that the additional time for analysis provided for is no longer needed as submissions confirmed to us that there were no new substantive issues that we needed to address.
4. Annual batching of benefit-based charge adjustments
This amendment requires Transpower to process benefit-based charge adjustment events in one annual batch, which reduces uncertainty by removing the risk of charges differing from customers' expectations due only to the order in which events are processed. It also lowers administration costs for Transpower and its customers. The Authority has made some modifications to the drafting of this amendment as compared with the proposal the Authority consulted on. However, the Authority considers that these modifications are largely technical and non-controversial, better achieve the intent of the original proposal, and are consistent with submissions which supported the intent of batching. The Authority considers this amendment will be for the long-term benefit of consumers as it reduces the cost of administering the TPM, while continuing to deliver on the TPM's policy intent.
5. Remove the 'substantial sustained increase' (SSI) adjustment clause
This amendment removes the adjustment event that is triggered when electricity consumption or generation from an existing plant increases by at least 25% and is expected to remain higher for at least five years. The Authority considers that removing this provision, which has proven unworkable in practice, will be for the long-term benefit of consumers by making the TPM more robust and reducing complexity and compliance costs.
6. No extension to the first simple method period
The Authority has decided not to approve Transpower's request to extend the first simple method period from its current end date of 31 March 2028 to March 2029, or March 2030 if necessary. This was a finely balanced decision. The objective of the extension was to ease Transpower's resourcing conflict between updating simple method allocators and its operational review of benefit-based charges. It may also have avoided the costs of an additional consultation on simple method allocators if Transpower's operational review identifies material improvements that justify prompt implementation to bring forward improvements. However, the benefits are uncertain and would likely be relatively minor, and the Authority considers they likely would not outweigh the costs of an extension, primarily as changes to a core allocation mechanism potentially weaken regulatory certainty.

Next steps

The approved Code amendments will come into effect on 1 April 2027.

The Authority will continue to identify opportunities to improve the TPM, where there is evidence that doing so will be for the long-term benefit of consumers.

Transpower is continuing its operational review of the TPM, focusing on potential improvements to the simple and standard methods for allocating benefit-based charges. While we expect this review to focus on the systems and process used by Transpower to implement the TPM, the Authority will continue to work closely with Transpower and engage with stakeholders to assess any Code change proposals arising from the review.

Contents

Executive summary **2**

1 Purpose **6**

2 Decision 1: To exempt battery storage from the simple method demand factor **9**

3 Decision 2: To remove the two-year lag until an updated WACC applies to calculate benefit-based charges **12**

4 Decision 3: To use the standard method for allocating 50% of the capital cost of anticipatory connection assets **14**

5 Decision 4: To batch adjustments for benefit-based charges **20**

6 Decision 5: To revoke the 'substantial sustained increase' adjustment event **24**

7 Decision 6: Not to extend simple method period 1 ..... **25**

8 Drafting refinements **29**

9 Other topics on which the Authority sought feedback **30**

10 Our decisions support our main statutory objective **32**

11 Next steps **34**

12 Attachments **34**

Appendix A Comparison of historical power flows **35**

Appendix B Approved Code amendments **39**

1 Purpose

Improving how the Transmission Pricing Methodology works

1.1 This paper sets out the Electricity Authority Te Mana Hiko (Authority) decisions on the six amendments to the Transmission Pricing Methodology (TPM) proposed in its consultation paper published on 29 June 2026.

1.2 The approved amendments aim to address known implementation issues and improve how the TPM works, in keeping with its core design. The amendments will:

(a) better align transmission charges with transmission customers' benefits

(b) reduce volatility and uncertainty in charges

(c) lower administrative and compliance costs.

1.3 In doing so, these amendments will improve how transmission pricing supports the efficient operation of the electricity industry, including providing greater confidence for investment, for the long-term benefit of consumers.

1.4 Transpower is continuing its operational review of the TPM, focusing on potential improvements to the simple and standard methods for allocating benefit-based charges (BBCs). While we expect the operational review to focus on the implementation of the TPM, the Authority will continue to work closely with Transpower and engage with stakeholders to assess any Code change proposals arising from its operational review.

Decisions covered in this decision paper

1.5 This paper addresses the Authority's decision to:

(a) refine the simple method treatment of battery storage so that battery storage is not charged disproportionately compared to other supply technologies

(b) remove the two-year lag between when an updated weighted average cost of capital applies to determine Transpower's maximum allowable revenue, and when it applies to calculate BBCs

(c) use the standard method (instead of the simple method) to allocate 50% of the capital cost of anticipatory connection capacity

(d) enable the processing of benefit-based charge adjustments in one annual batch

(e) remove the 'substantial sustained increase' adjustment event for BBCs

(f) make minor amendments to the drafting of the TPM to improve clarity and remove redundant provisions.

1.6 The paper also sets out the Authority's reasons for not extending the first simple method period by up to two years.

1.7 We have noted submitters' feedback on the other topics raised in the consultation and will consider any next steps on these matters at a later date. See Chapter 9.

Consultation

1.8 The Electricity Industry Act 2010 (Act) requires the Authority to consult on any proposals to amend the Electricity Industry Participation Code 2010 (Code) and on a regulatory statement before making changes to the Code.

1.9 The Authority released its consultation paper on 29 June 2026, consulting on six proposals to amend the TPM (plus minor technical drafting refinements) – five over a four-week period and the proposal on the allocation of costs of anticipatory connection capacity over a six-week period.

1.10 Each proposal included a regulatory statement with a statement of the objectives, an evaluation of the costs and benefits, and an evaluation of alternative means of achieving the objectives, of the proposed amendment.

1.11 The Authority received submissions from 15 parties, six of which addressed all proposals.

Submissions	Topics covered by submission					
	Batteries	WACC	Batching	SSI	Extension	Anticipatory Capacity
Alan Eyes	●					●
Electricity Networks Aotearoa	●	●	●	●	●	●
Fonterra Cooperative Group	●	●	●			●
Genesis Energy	●	●	●			●
Horizon Energy Distribution			●			
IEGA	●	●	●	●	●	●
Lodestone	●	●	●	●	●	●
Major Electricity Users Group	●	●				●
Meridian Energy	●					
Orion New Zealand	●	●	●	●	●	●
Powerco			●			
Top Energy						●
Transpower	●	●	●	●	●	●
Unison and Centralines	●	●	●	●	●	●
Vector	●	●	●	●	●	

Feedback on context and approach

1.12 There was general support from submitters for the proposed approach to assessing the proposals (ENA, Genesis, IEGA, Lodestone, Meridian, Orion, Transpower, and Unison and Centralines). This approach involved considering:

(a) whether the proposals were consistent with the 2020 TPM Guidelines, which contain our view on how the Authority's main statutory objective applies to transmission pricing

(b) the impact of the proposals on stakeholders, including:

(i) promoting stakeholder engagement in transmission investment

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

(iii) reducing complexity and administrative cost

(iv) promoting relatively predictable and stable charges.

1.13 Lodestone suggested that the assessment should also consider the predictability of charges for parties making irreversible investment decisions, the proportionality of charges, and neutrality of charges across technologies and fuels. Fonterra submitted that the revenue smoothing that the Commerce Commission applies to Transpower's maximum allowable revenue should also apply to BBCs. It said that 'large sudden step changes make it very difficult for businesses to build reliable financial cases' for electrification.

1.14 ENA stated that some members would welcome more information from Transpower about the components of transmission charges, allocation methods, and price forecasts.

1.15 As noted in the consultation paper (and in the above paragraph), promoting predictability is an explicit aim of the amendments.[1] The TPM Guidelines seek charges that reflect costs and each customer's share of positive net private benefits derived from investments. They also seek to avoid discrimination between transmission customers unless this is necessary to achieve the Authority's main statutory objective, while also requiring that the economic benefits and costs of precision are balanced with the economic benefits and costs of practical considerations including certainty. The Authority therefore considers that it has sufficiently accounted for predictability.

1.16 Together, however, this feedback highlights the value that transmission customers attach to having enough information to understand and anticipate future transmission charges.

1.17 Material year-on-year changes are often driven by factors Transpower knows about in advance. These include Commerce Commission-approved revenue increases and investments allocated under the simple method.

1.18 The Authority has previously indicated that Transpower could give customers clearer forward signals, including the reasons for projected changes in each customer's charges. The Authority considers Transpower could further improve its forecasting and forward signalling, to give customers greater transparency and predictability. The Authority anticipates that Transpower will address this in its operational review.

1.19 Submitters also raised broader issues about the TPM. Some said changes in the electricity industry mean the TPM is no longer fit for purpose and needs a more fundamental review (Alan Eyes, Fonterra, MEUG).

1.20 We acknowledge these views. However, the TPM was designed to deal with a changing electricity industry, including:[2]

(a) electrification: the beneficiary-pays approach provides incentives for affected parties to scrutinise and select the best transmission and non-transmission investments to support growth in load

(b) new generation and demand: efficient price signals on where to connect support getting the best use out of transmission and local networks, and ensure those who benefit from new transmission investments pay for them

(c) technological transformation: fixed-like charges provide an efficient cost-recovery mechanism as new technologies change how consumers engage with electricity markets, and are robust against inefficient cost-shifting enabled by new technologies.

1.21 Broader questions about the TPM's overall design are outside the scope of this decision paper. The Authority considers that the TPM's core framework remains sound, but will pursue targeted refinements where it considers these are necessary to ensure it continues to work as intended.

[1] See consultation paper at paragraph 1.6.

[2] For example, see the section on 'material change in circumstances', chapter 4 of the 2020 Decision paper.

2 Decision 1: To exempt battery storage from the simple method demand factor

Our decision

2.1 The Authority will amend clause 61 of the TPM so that the demand factor in clause 64(2) of the TPM does not apply to battery storage offtake.[3]

2.2 This change better reflects how battery storage operates and reduces the risk that batteries will be allocated disproportionately high BBCs under the simple method.[4]

The issue

2.3 Under the TPM's simple method, historical grid flows are used as proxies for the benefits of transmission investment. For each of 21 investment regions, customers' allocators are based on their shares of historical offtake and injection.

2.4 Large battery storage can both take electricity from the grid and inject it into the grid. When a new large battery connects, the simple method charges it for both offtake and injection. The Authority accepted this treatment as consistent with the simple method when it made its final decision to adopt the new TPM in 2022.

2.5 However, the simple method calculation also applies a demand factor of 1.67 to offtake measures, which increases offtake allocators and charges relative to injection. The demand factor applies to all offtake, in part to reflect that electricity is more valuable to end-users than to generators, as indicated by the value of lost load.

2.6 We consider the demand factor should not apply to offtake by large batteries. Unlike end-users, batteries do not consume electricity for final use. Also, an outage may cause a battery operator to charge or discharge at a potentially less advantageous time and lose earnings, but that impact is much less than the value of lost load to end users. In these respects, large batteries are like other supply technologies and should also not attract the demand factor.

2.7 Applying the demand factor to large batteries risks allocating them disproportionately high BBCs under the simple method. This could inefficiently discourage investment in large battery storage. The Authority considers that it should address the issue now, ahead of the substantial pipeline of planned investment in large battery storage.

What we proposed

2.8 We proposed 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.

2.9 This adjustment would be made through clause 61 of the TPM to reverse the demand factor that is applied to offtake under clause 64.

Submitters' views and our assessment

2.10 Half of the submitters who commented on this proposal supported the proposal and the reasons for not applying the demand factor to battery offtake (Genesis, Lodestone, Meridian, Orion, Unison/Centralines, and Vector).

2.11 Fonterra submitted that large battery storage should not attract *any* BBCs because batteries are unlikely to drive new grid investments. Lodestone suggested exempting battery storage

[3] Battery storage is a term defined in the TPM. The TPM also defines large plant as plant with capacity of at least 10MW.

[4] Large battery storage (>10MW) excludes smaller batteries connected to households or small businesses typically used for backup power or to store rooftop solar generation for self-consumption.

from all simple method BBCs, provided the same exemption applied to distributed generation.

2.12 MEUG and Alan Eyes opposed the proposal because they were concerned it would create a technology-specific bias. MEUG also submitted that the proposal needed further discussion. ENA submitted that the treatment of batteries should instead be reviewed as a whole, because piecemeal amendments risk creating inconsistencies and unintended consequences.

2.13 The Authority agrees the TPM should avoid bias for or against particular technologies, and that piecemeal changes can create inconsistencies. However, as the consultation paper explained, this amendment would resolve an existing inconsistency. Large battery storage is treated differently under the simple method compared to other supply technologies and compared to how other allocation methods and charge types provided for in the TPM apply to large battery storage.

2.14 Transpower did not support the proposal. It submitted it had not seen evidence that the existing approach harms efficient operation or competition, and it was concerned about implementation and administrative costs. Like Transpower, Vector was concerned the Authority may not have given enough weight to implementation complexity. We consider these concerns further below.

2.15 Transpower also submitted that considering this topic through its operational review workstream of BBCs would produce a more efficient and durable solution. By contrast, other submitters (Genesis, Lodestone, Orion, Unison and Centralines) supported the Authority's proposal to make the change before Transpower completes its operational review of BBCs.

2.16 Lodestone noted that the TPM defines grid scale battery storage more broadly (including pumped hydro) than the narrower electro-chemical definition for Battery Energy Storage Systems in another of the Authority's recent consultation papers.[5] The Authority had noted this in its consultation paper but is not currently planning to align or amend the TPM definition for battery storage because it is fit for the purpose of allocating transmission charges.

Addressing implementation matters

2.17 The Authority understands that Transpower's implementation and administrative concerns relate to system changes it would need to make to calculate simple method allocators and having to obtain separate metering data, which may be a challenge for large battery storage that is embedded or co-located with load.

2.18 The Authority accepts that implementation issues and administrative costs will arise, although the extent of them will depend on operational choices. For the reasons set out below, we consider these costs are outweighed by the benefits of improved competition and more efficient operation of the electricity industry, particularly given the substantial pipeline of planned investments in large batteries.

2.19 The Authority does not consider implementation would impose excessive additional costs. When a new large battery connects (including within a network), Transpower must already calculate separate benefit-based allocators for it, including under the simple method. Reversing the demand factor when calculating adjustments is a minor additional step.[6]

[5] See footnote 17 of the TPM consultation paper. For the narrower definition, see the Authority's 29 September 2026 decision https://www.ea.govt.nz/documents/10972/Wholesale_market_arrangements_for_battery_energy_storage_systems_-_Decision_paper.pdf.

[6] This can be seen by inspecting the Simple Method Allocation Model used to calculate customer allocations for low value benefit-based investments, Appendix B to Transpower's Assumptions Book.

2.20 Following this amendment, Transpower will also need to back out the demand factor from offtake that is attributable to an embedded battery when it calculates simple method allocators in future simple method periods.

2.21 This will involve Transpower gathering information on a battery's mean historical annual offtake (cl 65 (4)) for the preceding five-year period to calculate a battery's share of the relevant regional demand group's regional net private benefit (before reversing the demand factor). This is not very detailed data, and the calculation is also not complicated.[7]

2.22 For embedded large batteries, we note that battery operators have an incentive to disclose such information to hosting transmission customers or Transpower as it would reduce transmission charges attributable to them.

2.23 The Default Transmission Agreement (clause 12) provides for Transpower to access such data for embedded batteries from its transmission customers, as Transpower would need such information to meet its transmission pricing obligations. As the focus is on large batteries which may also inject, these plant will be known to or identifiable by Transpower.

2.24 If such input data does not exist, as Lodestone raises as a possibility in its submission, then Transpower must determine it under clause 10(3) of the TPM. The Authority notes a process for estimating such data exists under 83(3) for new customers.

2.25 We also note that it remains open to Transpower to further consider how to ease implementation or administrative costs as part of its current operational review, or any other continuous improvement initiative.

2.26 Transpower also notes that, as the approach would only apply to newly connecting batteries, it would create a period of different treatment for the four large battery storage plants already connected, until the simple method allocators are updated (see also chapter 7).

2.27 The Authority disagrees. We consider that, when the amendment comes into effect, Transpower will be required to update the allocations made to existing large battery storage plant to exclude the demand factor, in order to ensure that those allocations continue to comply with the TPM. We note that this is different from the usual position which is that allocations generally remain fixed (apart from adjustments). However, this amendment would be changing the underlying basis on which the calculation was made and we consider that would need to be reflected in the allocations used going forward. There would thus not be a material period of different treatment between existing and any new large batteries (absent the impact of 'batching').

[7] See Transpower's spreadsheet model referenced in the previous footnote.

3 Decision 2: To remove the two-year lag until an updated WACC applies to calculate benefit-based charges

Our decision

3.1 The Authority will amend clause 39 of the TPM to remove the two-year lag between when the weighted average cost of capital (WACC) as determined by the Commerce Commission applies to setting Transpower's maximum allowable revenue and when that WACC applies to calculate BBCs.[8]

The issue

3.2 Under the TPM as it is currently drafted, there is a two-year lag between when an updated WACC applies to set Transpower's maximum allowable revenue and when that WACC is used by Transpower to calculate BBCs.

3.3 The original reason for the lag was that BBCs should reflect the actual (audited) costs of investments, using depreciation and opening asset base values for the preceding financial year, to ensure charges for the capital components are consistent with Transpower's individual price-quality path.

3.4 The intent was to avoid the administrative burden of wash-ups undertaken to prevent under- or over-recovery due to inevitable forecast errors about the value of the assets, including newly commissioned assets.

3.5 However, based on experience since implementation of the TPM, we now consider that this lag has few if any material administrative benefits but likely has unintended negative impacts.

3.6 Under the Commerce Commission's current input methodology settings, the WACC is revised once every five years to apply for a full regulatory control period. This means that two different WACC rates apply two out of every five years for BBCs. The negative impacts are:

(a) the inefficiency from BBCs not fully reflecting their current cost

(b) the higher complexity for customers, leading to confusion and potentially errors when managing costs and assessing investments in generation or other business, without there being equivalent or greater benefits to justify the complexity.

3.7 In September 2026, the Commerce Commission reached its final view that it will adopt a trailing average approach to estimating the real risk-free rate for the cost of debt.[9] That would change Transpower's WACC rate every year, so that the WACC used to calculate BBCs would always be different to the WACC used for setting Transpower' revenue allowances and other transmission charges under the TPM as currently drafted. This difference in the two WACCs increases inefficiency and complexity.

3.8 The WACC lag (and removing it) 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. Impacts vary by customer – for example, generation does not attract residual charges and so would incur relatively higher costs where there was over-recovery through BBCs and lower costs where there was under-recovery.

3.9 We are addressing this issue now as the efficiency and distributional impacts of the current approach will grow over time as the value of assets recovered through BBCs grows.

[8] As the WACC for BBCs will align with the one used to set regulated revenues from 1 April 2027, this amendment will not have an effect until Transpower's next regulatory control period starting in 2030, or when the Commerce Commission adopts the trailing average approach to the real risk-free rate for the cost of debt (see para 3.7), if that is implemented sooner.

[9] Commerce Commission 2026, Stakeholder-email-advising-reasons-for-the-revised-Notices-of-Intention-23-September-2026.pdf

What we proposed

3.10 The Authority proposed to amend clause 39 of the TPM to remove the two-year lag between an updated WACC applying to Transpower and it being used to calculate BBCs.

Submitters' views and our assessment

3.11 We received 10 submissions on the proposal.

3.12 Most submitters supported the proposed amendment. They agreed that aligning the WACC used for BBCs with the current regulatory WACC would improve cost reflectivity, investment signals, predictability, and administrative simplicity.

3.13 ENA, Lodestone, Unison and Centralines, Orion, Genesis, and MEUG generally agreed with the Authority's description of the issue. They supported addressing the issue now to prevent negative impacts from continuing or increasing over time.

3.14 IEGA suggested that the Authority's analysis should also consider whether the gains from removing the lag are greater than the losses from applying the WACC to forecast rather than actual asset values. We consider that the benefits of the WACC lag are few if any, and are outweighed by the negative impacts on customers from the complexity caused by different WACCs applying under the current drafting.

3.15 Fonterra submitted the proposal was a distraction. It considered the more important question was why Transpower's WACC includes premia above the cost of government financing. We note this broader question is outside the Authority's remit, and note the amendment applies to whatever WACC methodology is applied by the Commerce Commission.

3.16 Transpower agreed that aligning the WACC used to set its revenue with the WACC used for BBCs would simplify administration. However, it submitted the efficiency benefits would not increase over time and that correcting the WACC lag is now mainly a distributional issue.

3.17 The Authority does not agree. As more transmission revenue is recovered through BBCs, any errors customers make in estimating or understanding those charges – and the resources they may apply to avoid such errors – will increase.

3.18 Several other submitters also highlighted the distributional effects. ENA, Orion, and Vector said these effects should be acknowledged. Vector suggested a one-off adjustment to offset these distributional effects would improve the durability of the TPM. However, we consider any benefits of a one-off adjustment would be outweighed by the complexity of considering, designing and executing with sufficient precision such a mechanism.

3.19 As was set out in the consultation paper, the Authority acknowledges that the WACC lag has impacted the distribution of charges. It has kept BBCs lower for load and generators, while load has temporarily paid higher residual charges than it would have without the lag.

3.20 While these distributional impacts are relevant to stakeholders, they are not a primary consideration in our assessment. The Authority must be guided by whether the amendment would promote its main statutory objective, including the efficient operation of the electricity industry for the long-term benefit of consumers.

3.21 The Authority considers that the amendment would improve the efficiency of the electricity industry for the long-term benefit of consumers. Past distributional impacts are relatively minor and as such the amendment would not materially affect the TPM's durability. This is because the proportion of transmission charges recovered through BBCs is still relatively low, and for load customers the impacts of the lag on BBCs and residual charges have offset each other to some extent. With the WACCs now aligned, the amendment would mean such effects should also not occur again.

4 Decision 3: To use the standard method for allocating 50% of the capital cost of anticipatory connection assets

Our decision

4.1 The Authority will amend clause 27(3) of the TPM to require Transpower to use the price-quantity[10] standard method – rather than the simple method – for allocating the 50% of the capital costs of anticipatory connection assets that should be recovered through a benefit-based method (with the other 50% continuing to be socialised among connection customers).

4.2 The Authority will also adopt small clarifying consequential amendments to clauses 27, 44 and 59 that Transpower proposed in Attachment 2 to its submission of 7 August 2026.

4.3 We have decided to progress this amendment now (rather than consider it early in 2027 as the consultation paper suggested we might). The additional time allowed for in the consultation paper was to enable us to conduct further analysis on these issues if required. However, the Authority has been able to complete the necessary analysis without the need for that additional time, noting that submissions have generally reconfirmed our understanding of the issues.

The Issue

4.4 The TPM currently allows Transpower to recover the capital cost of anticipatory transmission connection capacity in the following way:

(a) 50% socialised among all connection customers through connection charges

(b) 50% paid by existing transmission customers expected to benefit from the anticipatory capacity. The simple method is used to allocate these charges, but only 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.

4.5 This approach was intended to balance:

(a) giving transmission customers incentives to scrutinise anticipatory capacity proposals, which helps reduce the risk of inefficient overbuilding when costs are fully socialised

(b) avoiding disproportionately high charges in regions with few beneficiaries, because concentrating costs too heavily could discourage efficient investment in anticipatory capacity.

4.6 The simple method allocates transmission investment costs using predetermined shares. These shares are based on historical power flows within and between regions.

4.7 In practice, this approach means that within-region offtake tends to be identified as the main beneficiary of grid investments. This reflects that the simple method was designed with repeat expenditure (maintenance and replacement of existing grid assets) in mind.

4.8 Historical flows are not reasonable proxies for positive net private benefits when anticipatory connection capacity supports future investment in load or generation that would fundamentally change market dynamics and power flows.

[10] The amendment makes this explicit for clarity. Transpower noted there are two standard methods, the price quantity and resilience method. It is difficult to see how investments made in anticipatory connection capacity would be defined as mitigating a resilience risk (or vice versa).

4.9 The proposed anticipatory connection capacity in Northland, which did not proceed, illustrates the issue. Anticipated generation investment would have changed Northland from a net importer to a net exporter of electricity. The main beneficiaries of those exports would probably have been in other regions, particularly Auckland. However, under the simple method, Northland consumers would have been allocated most of the 50% share. We consider that this allocation would not have been efficient.

What we proposed

4.10 We proposed amending the TPM to require Transpower to use the standard method, rather than the restricted simple method described at paragraph 4.4(b), to calculate net private benefits when allocating the part of the capital cost of anticipatory connection assets that is not socialised among connection customers.

4.11 The standard method uses bespoke market modelling to assess the impact of a transmission investment. It is thus better able than the simple method to identify who would benefit over time from a transmission investment that may change market dynamics, given that the simple method relies on pre-determined allocators based on historical flows.

4.12 This approach would be consistent with the TPM Guidelines and the Authority's main statutory objective because it:

(a) is an immediate effective solution to the issues identified above

(b) promotes efficiency because tailored modelling of expected beneficiaries of anticipatory capacity should allocate costs more closely to future positive net private benefits than the simple method

(c) encourages expected beneficiaries to scrutinise anticipatory investments, while avoiding inefficient opposition that may arise when the simple method allocates costs out of proportion to customers' benefits.

4.13 The Authority also considered that the standard method would strike an appropriate balance between precision and practicality, acknowledging that:

(a) the standard method involves greater administration cost to Transpower than the application of pre-determined simple method allocators

(b) additional costs should not be too high as anticipatory capacity investments are unlikely to be common

(c) the extra effort is likely justified as it supports scrutiny of non-routine transformative investments that involve part-socialisation of cost.

Submitters' views and our assessment

4.14 Submitters generally agreed with our description of the issue but were split on the best way forward.

4.15 ENA, Genesis, Top Energy, and Unison and Centralines agreed with the proposal to change from the simple to the standard method to allocate 50% of the capital costs associated with the anticipatory part of a connection asset. ENA supported the proposed amendment as an interim step while the treatment of non-arrival risk could be considered further as part of Transpower's TPM operational review.

4.16 Alan Eyes and MEUG called for a more fundamental review of who should bear the risk and cost of anticipatory capacity, rather than placing that burden on current transmission customers. MEUG promoted a first-principles review involving the Commerce Commission

and MBIE. Alan Eyes suggested Transpower should bear the risk or that the costs should be socialised.

4.17 IEGA, Lodestone, and Orion disagreed with the proposal, suggesting costs should be socialised, with Orion saying this should apply only until the new customers connected.

4.18 Submitters who favoured socialisation were mainly concerned that identified beneficiaries might not ultimately benefit from the connection asset, that costs could be concentrated on customers in smaller regions, and that charges are unnecessary or ineffective as a way to motivate increased scrutiny of proposals.

4.19 Transpower also opposed the proposal and offered some alternatives, including sharing more or all of the costs via connection charges (socialisation). Its reasons included that:

(a) it has not seen evidence that the standard method would result in better allocations

(b) the simple method could be a better option in certain circumstances

(c) future beneficiaries and future benefits are unknown or uncertain with allocations highly sensitive to modelling assumptions[11]

(d) BBCs were not designed to allocate the cost of anticipatory connection assets.

4.20 Transpower suggested that one option might be to only require use of the standard method for anticipatory connection capacity investments costing more than $30m and otherwise socialise such costs.

4.21 The Authority acknowledges these submissions. However, as explained in the consultation paper, our current priority is to improve the method used to allocate that 50% of the cost of anticipatory connection assets that is not socialised among all connecting customers.

4.22 It is beyond the scope of this paper to revisit the earlier decision to recover some portion of the cost of anticipatory capacity through BBCs. This approach was taken to give transmission customers clear incentives to scrutinise proposals and help counter the risk of inefficient overbuilding when costs are fully socialised. The consultation document therefore focused on options for improving benefit-based allocation.

4.23 We also did not consider an alternative option to change which costs Transpower can recover from its customers (eg excluding anticipatory investments), advocated for by some submitters, as that is for the Commerce Commission to determine under Part 4 of the Commerce Act.

4.24 The Authority is aware Transpower is undertaking an operational review to identify improvements to the implementation of the standard method for benefit-based charging. We welcome any resulting initiatives, including proposals to amend the TPM, that would improve implementation of the standard method.

4.25 However, the Authority considers that the concerns Transpower has raised to date with the implementation of the standard method do not outweigh the benefits of making the amendment now.

4.26 The simple method has been shown to be not well suited to allocating costs of non-routine transmission connection investments intended to facilitate a material change in future grid use.

4.27 In such situations, reliance on historical power flows is unlikely to allocate costs to customers expected to benefit from the anticipatory capacity. Retaining the simple method approach for

[11] One reason for Transpower's objection is that it would need to work out how to deal with future beneficiaries that do not and may never exist (p3). The objection seems misplaced, as any modelling of transmission investment to address growth in demand or supply has to deal with such uncertainties now.

this purpose (including for investments below $30m as Transpower submitted as an option) could therefore be inconsistent with the Authority's statutory objective.

4.28 By contrast, the standard method uses tailored market modelling. It can test forward-looking factual and counterfactual scenarios, including different assumptions about future entry by generation or load customers that are not yet identified. This allows it to identify a broader or different group of benefiting customers than the historical power flow patterns used in the simple method.

4.29 For these reasons, the amendment should improve allocation outcomes. This remains the case even though the modelling will require assumptions and the results may be sensitive to them, as this is a normal feature of modelling.

4.30 Some submitters suggested that, as standard method allocations are sensitive to modelling assumptions, the proposal needed to come with safeguards, including:

(a) early visibility, before decisions are made, of the likely allocations for affected customers, and sufficient information to understand, test and challenge modelling of and the case for proposed anticipatory investments (Genesis, Lodestone, Unison and Centralines)

(b) clarity that consultation obligations apply (Genesis, Lodestone)

(c) clear rules for what happens if actual outcomes differ materially from those assumed (Genesis, Unison and Centralines).

4.31 We note that clause 15 of the TPM requires Transpower to consult the customers who will pay connection charges before the charges are finalised. This requirement covers the cost of anticipatory connection assets that are socialised among connection customers or allocated via a benefit-based method.[12]

4.32 Transpower Capital Expenditure Input Methodologies also address how the Commerce Commission treats anticipatory connection investments and how these will be consulted on. This includes a requirement to include sufficient information so consumers and affected parties can meaningfully submit on the anticipatory capacity investment.[13]

4.33 Given these existing requirements, the Authority does not consider Transpower is correct that there would be increased administrative cost due to additional consultation caused by the proposal.

4.34 That said, the Authority notes that there may be a case for further and better consultation in relation to the TPM more generally. Stakeholders have more broadly asked for earlier and better information about likely allocations so they can test the modelling and underlying assumptions before investment decisions are made.

4.35 The Authority agrees such scrutiny is important, as finalised allocations are fixed and would not change just because actual outcomes differed from those assumed in the modelling. We are therefore open to considering amending the consultation clauses in the TPM if that would further improve scrutiny and transparency at reasonable cost. We understand that Transpower will consider closely-related concerns through its operational review of benefit-based charge implementation.

[12] The Authority notes that this aspect of clause 15 applies notwithstanding that part of the capital cost associated with the anticipatory connection asset is recovered through BBCs. This is because, while clause 26(5) deems there to be an anticipatory BBI for the purposes of the calculation methodology, it does not fundamentally change the fact that this is a connection asset subject to connection charges.

[13] See chapter 6, p79 on of https://www.comcom.govt.nz/__data/assets/pdf_file/0020/337610/Part-4-IM-Review-2023-Final-decision-Transpower-investment-topic-paper-13-December-2023.pdf

Anticipatory interconnection capacity

4.36 In its March 2026 consultation, Transpower asked whether anticipatory interconnection capacity also raised a policy issue. The Authority noted in its June 2026 consultation paper that:

(a) during the TPM reform process it concluded such costs should be allocated through BBCs provided for by the TPM Guidelines, and this logic remains sound

(b) the simple method does not appear to be well suited for such investments.

4.37 Because Transpower was likely to consider this question through its TPM operational review, the Authority sought feedback on this issue and whether it needed earlier attention.

4.38 IEGA submitted that further work was needed to define how anticipatory interconnection capacity differs from other interconnection investment – for example, any upgrade to accommodate projected load growth is anticipatory. We agree this is a central question.

4.39 Fonterra submitted that, because major grid assets take a long time to build, Transpower must invest ahead of demand, but that the current benefit-based model creates an unfair burden on existing customers. It proposed that the capital cost of anticipatory capacity be gradually phased into Transpower's regulatory asset base, aligned with the rate at which that capacity is taken up, spreading the [unallocated] cost across all connections. Lodestone considered the anticipatory interconnection capacity should be recovered through the residual charge to avoid the risk of hold-up of efficient investments by the first mover.

4.40 Transpower submitted that its current BBC allocation process – the price-quantity standard method in its Assumptions Book – was not designed for anticipatory interconnection capacity. It said new bespoke analytical and business processes would therefore be needed.

4.41 However, we would expect Transpower's investment cases and current standard method processes to consider different forward-looking factual and counterfactual scenarios, including different patterns and probabilities of entry and exit by generation and load customers over time. Ultimately, any upgrade made to accommodate projected growth is anticipatory to some degree. Therefore, we expect that Transpower's existing analytical and business processes can also be used for this purpose.

4.42 Under the standard method, regional net private benefits over time must be discounted to present value. Allocations to existing customers should therefore reflect the benefits they receive over time, even if those benefits arise later when the anticipated new generation or load connects and begins contributing to the assets' capital and operating costs in proportion to its net private benefits.[14]

4.43 This does allocate the risk that future load or generation does not eventuate to existing customers, which is why scrutiny of investments by existing customers is important.

4.44 This approach to allocating costs of interconnection assets does not apply to connection assets, which explains the need for the specific 'first mover disadvantage' provisions for anticipatory connection assets.

4.45 Other submissions supported the use of benefit-based allocation methods, as long as the method was able to identify the right beneficiaries (ENA, Genesis, Top Energy, Unison and Centralines). ENA also supported further consideration as part of the operational review.

4.46 The Authority considers the submissions have not identified specific policy problems with the current application of benefit-based methods to allocate the cost of anticipatory interconnection capacity. However, we remain open to evidence of such problems.

[14] These matters were considered in Chapter 9 of the Authority's 2020 TPM Decision Paper.

Transpower's operational review provides an opportunity to identify and address any specific issues relating to anticipatory interconnection capacity:

(a) with the current estimation of net private benefits under the standard method that may be creating specific concerns about inefficient allocation of costs

(b) with the application of the simple method – for example, in situations where investment in 'low value' assets (to which the simple method applies) would likely transform power flows such that historical flows are no longer reasonable proxies for net private benefits.

5 Decision 4: To batch adjustments for benefit-based charges

Our decision

5.1 The Authority has decided to amend the TPM so that Transpower can process BBC adjustment events in a single batch at the end of a financial year, with adjusted charges for all customers taking effect in the next pricing year.

5.2 The batching must include adjustment events for which Transpower has reasonable information that they will occur after the end of the financial year in question but before the start of the next pricing year.

5.3 This amendment includes some modifications from the proposal the Authority consulted on. We consider that these changes better achieve the intent of the original proposal as they address potential implementation issues identified during consultation and reduce the administrative cost of wash-ups.

5.4 The Authority considers that the drafting changes to the proposed amendment are technical in nature and non-controversial, and allow the amendment to better achieve the intent of batching which submitters supported.

The issue

5.5 Under the current TPM, Transpower processes and calculates adjustments as it receives notice of them. As Transpower explained in its Code Amendment Request (p2-3):

"Adjustment events alter the allocations for all beneficiaries of the affected investments, but Transpower only updates the monthly BBCs within year for the directly affected customer (from the date of the event). All other customers' monthly BBCs are updated in the following pricing year (with BBC wash-ups applied to invoices up to two years later) creating uneven timing and compounding uncertainty …

Adjustments, and associated wash-up calculations, need to be performed in the order in which they occur. This process requires event specific modelling for the charge and wash-up calculations with internal assurance, and with corresponding tasks for customers – in particular, regulated lines companies, where accounting for transmission cost wash-ups is administratively complex driving disproportionate effort and assurance cost."

5.6 Transpower considers these costs are amplified by greater than expected volume of adjustments and which it projects to increase significantly.

5.7 Transpower estimates there would be ~30 adjustment events in 2026, suggesting a redistribution of $6.75m of charges among its customers.[15] Transpower also estimates the number of events would temporarily rise to over 90 in 2031.

5.8 By contrast, the number of adjustment events in the 2025/2026 financial year was 16, according to Transpower's BBI Allocation workbook v3 (and 4 adjustments in the first quarter of 2026/27 also suggest 16 for the full financial year).

What we proposed

5.9 Transpower proposed the TPM should be amended so it can treat most BBC adjustment events in a July to June financial year (except for an exiting customer) as occurring on a

[15] Based on ~$4.75m/21 events x 30 events. See p18 and p21 in Transpower's Code Amendment Request, https://www.ea.govt.nz/documents/10356/Appendix_D_-_CAR_-_Adjustment_Events_Batching.pdf

single pre-defined date (eg, 30 June), and for the adjustments to take effect the following April (the start of the next pricing year).

5.10 This batching would remove adjustments of customer charges during a pricing year and remove any backdating of charges and wash-ups or 'rebates' (see clause 83(11) of the TPM).

5.11 The Authority saw the merit of batching adjustments but noted that under Transpower's proposal a customer causing the need for an adjustment may not need to pay any BBC for a minimum of 9 months and up to 21 months. This could give that customer a temporary advantage over its competition and could undermine the durability of the TPM.

5.12 For example, an adjustment event occurring mid July 2027 would be part of the batch at the end of the financial year June 2028, and the causing customer would first start paying (updated) charges from the pricing year starting 1 April 2029.

5.13 Therefore, the Authority consulted on an alternative option that would allow batching but would significantly reduce the delay under Transpower's proposal. Under the Authority's preferred approach:

(a) the causing customers would be liable for paying (updated) BBCs from the batching date (1 July), rather than from the beginning of the next pricing year

(b) Transpower would be allowed to delay applying adjusted charges for customers other than the causing customer until the start of the next pricing year

(c) if it did delay applying adjusted charges for those other customers, Transpower would be required to adjust those customers' charges (via a wash-up) in the next pricing year so that they are not under or over-charged BBCs as a result of the delay

(d) the wash-up must include time value of money adjustments using Transpower's pre-tax WACC.

5.14 The Authority's preferred proposed approach to batching would reduce the delay until the causing customer paid updated charges to an average of six months (and a maximum of 12 months) compared to an average of 15 months (and up to 21 months) under Transpower's option.

5.15 While the Authority's proposed approach would not remove the need for wash-ups as under Transpower's proposal, it would still achieve the other objectives of removing the possibly arbitrary sequencing effects, having just one set of adjustment calculations per year, and reducing charge uncertainty and administrative costs for transmission customers and Transpower.

Submitters' views and our assessment

5.16 We received 11 submissions on this topic. All submitters supported batching of benefit-based charge adjustment events, because it reduces administrative complexity and improves predictability.

5.17 Most agreed with batching at a single annual date. Powerco suggested quarterly batching could be a better balance between accuracy and administrative cost. More frequent batching would significantly reduce the benefits of batching, however.

5.18 Fonterra supported batching but urged a smoothing mechanism to avoid large sudden step changes in charges. The Authority has not seen evidence that BBC adjustment events tend to cause large sudden and problematic step changes in charges, and notes the existing protections in the TPM (prudent discounts) against inefficiently large charges.

5.19 Several submitters, including ENA, Horizon Energy, and Orion, emphasised that any batching approach must preserve transparency and cost traceability by providing sufficient information on the incremental impacts of individual adjustment events. The Authority agrees transparency is important and understands that such transparency will assist with the accurate pass through of transmission charges to embedded customers.

5.20 Submitters expressed mixed views on whether causing customers should be charged from the batching date or from the start of the next pricing year (avoiding the need for wash-ups):

(a) some supported the Authority's approach to charge the causing customer from the batching date as this approach would better preserve cost-reflectivity and ensure timely cost sharing by customers that trigger the adjustments (Genesis, Horizon Energy, Powerco, Unison and Centralines)

(b) others preferred Transpower's original proposal as this would achieve the administrative benefits that Transpower is seeking and avoid unnecessary complexity, and because the cost advantage to the causing customer and any competitive neutrality concerns were not seen as a material consideration (ENA, IEGA, Lodestone, Orion, Transpower, Vector).

5.21 Transpower emphasised that its option involved only "a slight delay" and that any cost advantage to the causing customer is not material and may also have beneficial effects, because "the delay applying BBCs would coincide with the period where the plant is financially exposed – having incurred capital and commissioning costs but yet to realise full revenue or productivity benefits…"

5.22 However, the Authority is concerned the amounts involved could be material, as in the case of a very large customer such as a hyperscale data centre entering, so that a long delay in charging a new customer could negatively impact the durability of the TPM.

5.23 Further, the purpose of the TPM is to allocate the full economic costs of Transpower's services in accordance with the Authority's main statutory objective. This does not extend to using the TPM to pursue economic development objectives or to charging some transmission customers to help finance the entry of others.

5.24 Transpower also submitted that there was precedent for its proposal to delay charging the causing customer, as it echoes the delay in how the residual charge applies to a new transmission customer.

5.25 The residual charge allocation for a new customer is initially nil, because the gross energy measure used in the residual charge formula (which applies equally to all load customers) is lagged. A new customer's residual charge builds up as actual historical gross energy use enters the calculation. This approach ensures a new customer with new load is treated the same as an existing customer with growing load. By contrast, batching would initially treat new customers different to existing customers. As another example of 'precedent', new customers start being charged connection charges as soon as reasonably practicable.

The approach adopted

5.26 On 1 September 2026, Transpower wrote to the Authority proposing minor modifications to its previous batching proposal. These modifications would address the Authority's concern about the length of delay before a causing customer would be charged and achieve Transpower's aim to reduce administrative costs of wash-ups and consultation requirements.[16]

16 https://www.ea.govt.nz/documents/11163/Modified_Batching_proposal_1Sept2026.pdf

5.27 Under its modified proposal Transpower would have discretion to include in its annual batching those customers it knows will connect after the batching date but before the next pricing year starts. Both the causing customer and all other customers would have their charges adjusted from the next pricing year.

5.28 This modified proposal would reduce the delay before a causing customer is charged to an average of around 6 months (similar to the Authority's proposal above) while avoiding wash-ups. For example, if a customer is known to be connecting:

(a) in late July 2027, Transpower will include that event in its batching of events for the 26/27 financial year, adjusted charges to all customers will be consulted on from late 2027, and charges will take effect 9 months later, from 1 April 2028

(b) in March 2028, Transpower will include that event in its batching of events for the 26/27 financial year, adjusted charges to all customers will be consulted on from late 2027, and charges will take effect 1 month later, from 1 April 2028

(c) in April-June 2028, after the start of the pricing year on 1 April 2028, these will be part of batching for the financial year 27/28 for consultation late 2028, and will take effect 10-12 months later from 1 April 2029.

5.29 There will be some benefit-based charge events that Transpower may not know about in advance, for example the connection of embedded offtake plant. (The System Operator would likely be notified of new large embedded generation). As such, even under Transpower's revised proposal, it is still possible there would be instances of long delay until the causing customer starts paying (updated) charges.

5.30 However, Transpower has said that in practice it is 'highly likely' it will know of events in advance, and 'almost certain' they will occur at the planned time. This is consistent with the nature of actual adjustment events to date, as published in Appendix D to the assumptions book on Transpower's website.

5.31 If there was a delay in a customer connecting or the event does not occur, Transpower has said it would temporarily under-recover rather than do a wash-up (although this is still an option). The customer could be charged immediately after the delay.

5.32 The Authority considers this modified proposal is better able to achieve the intended outcomes of the original batching proposal. To provide greater certainty to transmission customers on how adjustment events will be treated, however, the Authority has adjusted Transpower's modified proposal to provide customers greater certainty that Transpower *will* include in its annual batching the events that have occurred or will occur after the batching date but before the next pricing year (where this is reasonably practicable to do), rather than providing Transpower with full discretion to determine when this will occur.

5.33 The Authority has decided to adopt this modified batching proposal, with the adjustment set out in the above paragraph. The Authority considers this is appropriate as the modified proposal better achieves the intent of the batching proposal that was consulted on, the modification is largely technical and non-controversial as it is consistent with the intent of batching which submissions on this topic supported.

5.34 The Authority has also amended Transpower's proposed clause 75(1A) which would have set 1 July 2026 for the transition to the new batching methodology to a new date of 1 April 2027 to provide for the transition to occur after the Code amendment comes into force. This avoids overly long delays for adjustment events in the first quarter of 2027, as under an earlier implementation date these would be batched at the end of June 2027 and causing customers would not get adjusted charges until April 2028.

6 Decision 5: To revoke the 'substantial sustained increase' adjustment event

Our decision

6.1 The Authority has decided to amend the TPM to remove the substantial sustained increase (SSI) adjustment event for BBCs in clause 86, as proposed in the consultation paper.

The issue

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

6.3 The TPM triggers an adjustment to allocations where a large plant experiences a substantial sustained increase in electricity consumption or generation. A substantial sustained increase is an increase of at least 25% since the last time the relevant customer's benefit-based charge allocations were calculated, and which is expected to persist for at least five years and is not associated with a significant plant upgrade.

6.4 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 embedded plant

(b) requires Transpower to make judgements about whether changes in a plant's consumption or generation can be expected to persist for at least five years. This requires speculation by Transpower, driving uncertainty, administrative effort and compliance risk

(c) covers situations that are generally addressed through other adjustment events (such as new connections, disconnections, and large plant connections or upgrades) or through periodic updates to simple method allocators.

What we proposed

6.5 The Authority proposed to remove substantial sustained increases as a benefit-based charge adjustment event under the TPM. This is consistent with Transpower's proposal from workstream 1 of its TPM operational review.

Submitters' views and our assessment

6.6 All seven submissions on this proposal supported it (ENA, IEGA, Lodestone, Orion, Transpower, Unison and Centralines, and Vector).

6.7 Submitters highlighted workability issues and improvement of the TPM's operation as key reasons for the removal of the SSI adjustment event.

6.8 The Authority has decided to amend the Code to remove the SSI adjustment event as it will improve the workability of the TPM, noting that many of the material changes in customer circumstances are captured by other TPM provisions.

7 Decision 6: Not to extend simple method period 1

Our decision

7.1 The Authority has decided not to approve the proposed extension of the first simple method period by a year to 31 March 2029 (with an option to extend it to 31 March 2030 if needed).

7.2 On balance, the Authority considers that the uncertain but relatively minor benefits of an extension do not outweigh its costs, which primarily relate to a potential reduction in regulatory certainty.

The issue

7.3 The simple method allocates the costs of transmission investments to beneficiaries based on power flows measured over a preceding five-year period.

7.4 The current (first) simple method period runs until the end of March 2028, using allocators derived from an analysis of power flows between September 2016 and August 2021.

7.5 The second simple method period would cover the period 1 April 2028 to 31 March 2033, using allocators based on power flows observed between September 2021 and August 2026.

7.6 Transpower estimates it takes around six months of planning, calculations, analysis and assurance to derive updated simple method regions and customer allocators. This would be followed by consultation on allocators and then on proposed pricing using new allocators.

7.7 Transpower planned to commence this process early August 2026, finishing June 2027.

7.8 Transpower is currently also progressing the second phase of its TPM operational review to identify issues with, and potential improvements to, current methods for benefit-based charging.

7.9 Transpower has requested an extension of the current (first) simple method period to 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.

7.10 An extension may also avoid administrative costs for Transpower and its customers associated with, potentially, duplicating the updating of simple method allocators. That is, without an extension, Transpower is required to run a process to update allocators by 1 April 2028 as currently required, and then may, potentially, undertake a further process to implement substantive changes (if any) to the simple method that may stem from the operational review – unless these do not need to or should not come into effect until the third simple method period in 2033.

What we proposed

7.11 As requested by Transpower, the Authority proposed to amend clause 60(1)(a) of the TPM to extend the first simple method period to the end of pricing year 2028 (that is, March 2029), or to the end of pricing year 2029 (March 2030) if needed.

7.12 This would help Transpower to resolve resourcing conflicts so that it can complete its operational review of its methods for benefit-based charging in a more timely manner.

7.13 The Authority noted its proposal was contingent on further information on whether:

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

(b) Transpower is able to provide suitable assurances 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.

7.14 The consultation paper noted that, if the Authority considers it lacks assurances on these matters, and depending on the submissions received on this proposal, the Authority may decide that Transpower should update the simple method allocators as currently required (that is, there would be no extension).

Submitters' views and our assessment

7.15 We received seven submissions on the proposal for an extension of the first simple method period (ENA, IEGA, Lodestone, Orion, Transpower, Unison and Centralines, and Vector).

7.16 Submitters generally supported the proposal to allow Transpower to extend the first simple method period so that it ends in March 2029 or March 2030 if needed. Lodestone did not support an extension to March 2030, unless evidence is presented that flows have been materially stable.

7.17 Submitters' reasons in support of the proposal included:

(a) efficiencies from avoiding duplication of work i.e. recalculation of simple method allocators on completion of work on the Operational Review's BBC workstream; and

(b) alleviation of Transpower's resource constraints.

7.18 Transpower considered the efficiency costs of a delay in updating historical allocators would be negligible.

7.19 ENA, Lodestone, and Unison and Centralines agreed with the backstop applying if updated allocators cannot be delivered within a reasonable timeframe. Unison and Centralines submitted an extension should be strictly bounded with no extension beyond March 2030. Lodestone asked the Authority to publish Transpower's assurance material on its ability to deliver updated simple method allocators by that date, and the Authority's own assessment of that assurance.

Additional power flow analysis

7.20 As part of its Code Amendment Request, Transpower had undertaken an analysis of power flows that led it to conclude that power flows are generally enduring and that simple method allocators remain materially appropriate.

7.21 To inform our assessment of the condition at paragraph 7.13, the Authority has since undertaken additional analysis of changes in half-hourly net power flows between the 21 regions between 2016-2021 and 2021-2026, the period that the second simple method allocators would be based on.[17] See Appendix A.

7.22 This analysis found that net power flow patterns have changed between the two periods, and to a material extent for some regions. Changes in net power flows in these regions likely reflect the investment in generation that has occurred across New Zealand and electrification (as well as events that affected demand in specific regions).

7.23 For a small number of regions (notably Northland, Hawke's Bay, Waikato, and Central North Island) both the absolute and percentage changes in net flows were substantial, suggesting flows have not been 'generally enduring' so that, for these regions at least, simple method allocators may no longer be materially appropriate proxies for net private benefits.

[17] See paragraph 9.18 and footnote 57 of the consultation paper for further background.

7.24 While net power flows have changed, the Authority also notes that it is likely that for the regions mentioned the impact of an extension on simple method allocators and charges tends to be more muted than implied by the change in net power flows because:

(a) these regions are the main beneficiaries of investments made in their own region – they will continue to be allocated most of the costs of those investments, even as offtake falls

(b) simple method charges for these regions tend to be dominated by charges for investments made in their own regions – this tempers the impact of even large reductions in shares of the cost of investments made in other regions.

7.25 These factors potentially limit the negative efficiency impacts of an extension of simple method period 1.

7.26 This analysis of regional power flows is an indicator of, but is not the same as, the power flow analysis that Transpower would undertake to determine simple method allocators. Therefore, it also cannot give a robust assessment of impacts on customers within simple method regions. Impacts may differ between customers as they may have experienced different rates of change. As such, we cannot be sure about the impact of an extension on individual customers – while these are likely small in the larger context of transmission charges, any distributional impacts may be material for individual customers (which could affect durability).

7.27 We therefore do not agree that it can be assumed that the existing simple method allocators remain materially appropriate and that, therefore, the impacts of extending the current simple method period would be limited (although they could be for a large number of participants). Moreover, we consider that extending the current simple method period could increase regulatory uncertainty, by deviating from the current allocation approach provided for in the TPM where the impacts of doing so on customers are unknown.

Comment on Transpower assurances

7.28 Transpower has told us it is confident its operational review will be completed in time for any Code amendment proposals to be able to be decided on in August 2028, so that these can be applied to the pricing year starting 1 April 2030.[18]

Overall assessment

7.29 The Authority's decision not to approve the extension to the first simple method period was finely balanced.

7.30 The Authority considers that the uncertain but relatively minor benefits of the proposed extension do not outweigh its costs, primarily a potential reduction in regulatory certainty.

7.31 The Authority recognises that its decision may mean that Transpower may delay its operational review of benefit-based charges as it has to prioritise updating the simple method allocators in time for the April 2028 pricing year. However, to date neither the nature of potential improvements to benefit-based charges that may flow from Transpower's operational review, nor their benefits or the benefits of bringing improvements forward in time have been identified.

7.32 Based on the scenarios set out in Appendix A, the impacts of an extension itself on charges allocated to regions are likely small, and so the associated efficiency impacts are likely small also, although our modelling did not allow us to test the impacts on individual transmission customers. However, an extension may also reduce regulatory certainty. A core feature of

[18] Based on a timetable provided by Transpower, it considers that making decisions in August would allow it to finish its calculation, analysis, and assurance processes to derive updated simple method regions and customer allocators for consultation mid-April in the following year, so new allocators can then be used to calculate and consult on indicative prices from around September to be applied from 1 April in the subsequent year.

the simple method is that allocators will be updated for each simple method period to reflect changes in power flows. Moving away from that, albeit temporarily, and in a manner where the actual impacts on transmission customers are uncertain, is likely to impact durability and regulatory certainty, which could in turn negatively affect investor confidence.

7.33 As such, the Authority considers that the proposal has not met the threshold for changing the Code to provide for an extension.

8 Drafting refinements

Our decision

8.1 The Authority has decided to adopt the drafting refinements as set out in the consultation paper. We have also decided to adopt the drafting refinement to clause 77 proposed by Transpower in its submission.

What we proposed

8.2 The Authority proposed various changes to the drafting of the TPM to remove provisions that are no longer relevant, correct typographical errors and make minor drafting improvements.

8.3 We considered the proposed amendments are technical and non-controversial and do not change the substantive operation of the TPM. Accordingly, we did not prepare a regulatory statement on these drafting refinements, consistent with s39(3) of the Act. Nevertheless, we included them with the consultation paper and have considered submissions received on them.

Submitters' views and our assessment

8.4 ENA supported the proposal on the basis that it would improve drafting clarity and remove redundant provisions.

8.5 In its submission, Transpower proposed an additional technical amendment to clause 77. Transpower stated:

The rationale for this proposed change is that clause 77 as drafted only applies the adjustment to the connection location where the customer connects and not to other connection locations where the new customer's offtake or injection affects allocations. The result is an over-recovery of connection charges over the rest of the pricing year, unless Transpower does a wash-up later or processes a separate voluntary under-recovery adjustment. Under the current clause, the wash-up is limited to the other customers at that connection location, rather than extending to other customers at other connection locations where allocations were affected.

8.6 The Authority agrees this is a technical and non-controversial amendment that would better reflect the intent of the TPM.

8.7 Unison and Centralines had no specific comments but encouraged the Authority to ensure any revisions maintain consistent terminology, clear cross-referencing, and alignment with existing TPM definitions, while avoiding unintended interpretive or operational impacts, particularly across related appendices.

9 Other topics on which the Authority sought feedback

Fixing shared connection asset allocators

9.1 The Authority sought initial feedback on a possible future amendment to the TPM to change the allocation of the cost of shared connection assets from a variable to a fixed share of costs.

9.2 The aim would be to stop annual recalculation of customers' shares of costs at a connection location, to reduce potential uncertainty about shares, reduce administration costs, and eliminate any inefficient incentives to alter offtake to shift charges to others.

9.3 None of the submissions indicated that the current approach was causing issues now. Transpower noted this approach had been in place many years and is well understood by customers.

9.4 Submissions tended to agree that the current approach could create an issue in the future, but that it did not need to be addressed now (eg, ENA, Orion, Unison and Centralines). Feedback included:

(a) fixing shares of cost was most like a commercial outcome in a workably competitive market (Lodestone); by contrast, IEGA thought it was a highly unlikely outcome

(b) if shares were fixed then the TPM would need additional provisions to adjust shares in case of certain events (ENA and Unison and Centralines)

(c) a rolling moving average could smooth out annual volatility (ENA and Vector).

9.5 The Authority acknowledges this feedback. As there is no evidence of a current problem and fixing shares may raise other issues, we will not progress this topic at this stage but may return to it at a later stage if the need arises.

Other emerging topics

9.6 The Authority also invited further feedback or information on two other topics, although it was not consulting on any proposals for change as such. The Authority does not intend to consider these matters further at present but may return to them at a later stage if the need arises.

9.7 A small number of submitters provided substantive comment on these topics.

Charges for remaining customers when one disconnects from a shared connection

9.8 The long-standing approach is that, when a customer at a shared connection disconnects, its share of charges is allocated to the other customers at that location. If the disconnecting customer is relatively large, this can cause sharp and unexpected increases in charges for the remaining customers. The TPM does offer customers some protection from inefficiently high transmission charges, through the standalone prudent discount policy.

9.9 Lodestone was concerned that the charges for remaining customers would not be cost reflective and that the prudent discount policy is not an effective protection as applying for a prudent discount places a very high burden on the affected party, particularly when that party is small. It thought a better approach would be to require charges to be recalculated based on what an optimally sized asset would be for the remaining customers, with the difference recovered through the residual charge. Genesis suggested an adaptation of the prudent discount mechanism for similar reasons.

9.10 The Authority is aware that a transmission customer is currently developing a prudent discount application because it faced a large increase in connection charges after a large

customer with whom it shared a connection asset disconnected. For now, Authority considers it is appropriate to wait for the outcome of that application before considering whether there may be a gap in, or some other problem with, the TPM or operational practices in this area that may need attention.

First mover disadvantage issues

9.11 The TPM protects a first customer that funds a new or upgraded connection asset from bearing all the costs, by providing a mechanism to charge later connecting customers for a share of the cost (based on the remaining economic life of the asset) which can then be rebated to the first customer.

9.12 This does leave the first customer exposed to a financial risk if further customers, who were expected to connect, do not connect or connect much later than expected. The Authority and Transpower consider this risk should not be addressed through the TPM, to preserve incentives on the first mover to negotiate an optimal size of the asset and decide how to best manage any financial risk.

9.13 Lodestone disagreed with this assessment, because it considers it is Transpower that drives the connection sizing and a developer that declines the larger asset may find it cannot connect at all. Further, it is not possible to share risk with a party that is not yet at the table. As such, Lodestone thought the risk should sit with Transpower.

9.14 Our understanding is that design decisions on connection sizing are driven by technical and grid reliability standards. It may be economic for new connection assets to be built to allow for later expansions, but this does not extend to Transpower being able to build and charge a customer for assets in excess of the customer's requirements without the customer's agreement.

9.15 Also, in addition to the provisions described at 9.11, the TPM provides for separate cost-sharing arrangements for anticipatory connection assets, that is, where Transpower decides to build a connection asset ahead of what known (current or pending) connection customers require, to accommodate anticipated growth at the connection.

9.16 As such, the Authority does not consider there is currently a case to consider expanding the available connection cost sharing provisions in the TPM. The Authority welcomes evidence of instances where customers cannot connect unless they accept and must pay for assets in excess of standards set out in the Connection Code, which would be a concern.

10 Our decisions support our main statutory objective

10.1 Consistent with section 32 of the Act, the Authority considers that the Code amendments – as detailed in this paper and its appendices – are necessary or desirable to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

10.2 The consultation paper *Transmission pricing methodology amendments 2026*[19], published on 29 June 2026, presented a regulatory statement for each of the proposed amendments where that is required by section 39 of the Act.

10.3 Consistent with section 39 of the Act, each statement included:

(a) a statement of the objectives of the proposed amendment

(b) an evaluation of the cost and benefits of the proposed amendment

(c) an evaluation of alternative means of achieving the objectives.

10.4 In developing and evaluating each amendment, we also had regard to:

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

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

10.5 The statements also provided an assessment of whether the proposed amendments complied with the intent of the TPM Guidelines, which they did.

10.6 Submissions confirmed the nature of the different considerations affecting the five approved amendments as discussed in chapters 2 to 6 above and did not provide new information that changed those assessments in the regulatory statements set out in the June 2026 consultation paper. A brief summary of those regulatory statements is provided on the following page.

10.7 No regulatory statement was required or provided for the various technical and non-controversial minor drafting refinements and tidy-ups to the TPM, including to remove redundant and outdated provisions (refer sections 39(1)(b), 39(1)(c) and 39(3) of the Act).

[19] Transmission pricing methodology amendments 2026

Summary of regulatory statements for approved amendments

Simple method for battery storage	
Objective:	Promote efficient investment in grid scale battery storage, by ensuring that such battery storage is treated consistently with other supply technology
Amendment:	Amend cl 61(1) of the TPM so the demand factor does not apply to offtake by battery storage
Assessed impact	Reduces risk of disproportionately high transmission charges to battery storage Efficiency benefits (noting investment pipeline) expected to exceed any extra administrative costs
Options	Identified alternatives were considered likely to create inconsistencies with the broader TPM framework or greater complexity
WACC alignment	
Objective:	Reduce distortions in transmission pricing; reduce complexity for customers and Transpower
Amendment:	Amend cl 39 so same WACC is used for setting max allowable revenue and BBCs
Impact	More cost-reflective BBCs, reduced complexity and administrative cost
Options	No credible alternative means have been identified
Anticipatory capacity for connection assets	
Objective:	Promote efficient investment in anticipatory connection assets
Amendment:	Amend cl 27(2)(d) of the TPM so Transpower must use the standard method to allocate 50% of the capital cost of anticipatory connection assets to beneficiaries
Impact	Improved allocation of cost promotes efficient anticipatory connection investment Extra administrative costs of using standard method expected to be modest and justified given size of anticipatory investments
Options	Alternatives not progressed as they would take a long time to develop (delaying benefits), or add complexity/uncertainty
Batching of adjustments	
Objective:	Reduce complexity and unpredictability for customers and reduce Transpower's administrative cost
Amendment:	Amend cl 75 and 81 of the TPM so Transpower can batch adjustments annually and reduce wash-ups
Impact	Transpower administrative savings of up to NPV $5.6m, reduction in customers' transaction costs
Options	Key alternatives had inefficiently long period where causing customers would not pay (adjusted) charges or other implementation concerns, or did not save as much in terms of administrative costs
Remove 'substantial sustained increase' (SSI) adjustment	
Objective:	Improve robustness of TPM and reduce complexity and compliance cost
Amendment:	Revoke cl 81(4) and 86 of the TPM as not currently workable, and issues they are intended to address are partially addressed elsewhere
Impact	Simplifies TPM, reducing administrative and compliance cost for Transpower and customers
Options	Alternatives to obtain data have been tried; other options retain risk of challenges to Transpower judgement/speculation that significant increases will endure more than 5 years

11 Next steps

11.1 The Code amendments will come into effect on 1 April 2027.

11.2 The Authority will continue to identify opportunities to improve the TPM, where there is evidence that doing so will be consistent with its main statutory objective and for the long-term benefit of consumers.

11.3 Transpower is continuing its operational review of the TPM, focusing on potential improvements to the simple and standard methods for allocating benefit-based charges. While we expect this review to focus on the systems and process used by Transpower to implement the TPM, the Authority will continue to work closely with Transpower and engage with stakeholders to assess any Code change proposals arising from the review.

12 Attachments

12.1 There are two appendices to this paper:

- **Appendix A** Comparison of historical power flows
- **Appendix B** Code amendments

Appendix A Comparison of historical power flows

A.1 This appendix summarises an analysis of changes in half-hourly power flows between the 21 simple method regions between 2016-2021 and 2021-2026.

A.2 These are the timeframes used to calculate, respectively, allocators for the 1st simple method period and, as currently required by the TPM, allocators for the 2nd simple method period.

A.3 This approach is not a replica of the methods used by Transpower to determine allocators for regional customer groups, but the Authority considers it provides a useful indicator of changes in power flows.

A.4 Figure 1 presents the histograms of half hourly net injection during the two different five-year periods across the regional interfaces. The histograms are presented from North to South, except for the last histogram (CSI_HV -> LNI_HV) which is the HVDC. The histograms:

(a) cover net flows across the 19 inter-regional interfaces for the 21 simple method regions for July 2016 - June 2021 (blue) and July 2021 - June 2026 (orange)[20]

(b) assume no direct connections between low voltage (LV) regions (and noting flows between high voltage (HV) regions are a function of net injection from several regions).

A.5 Table 2 presents summary statistics for these net flows between adjacent regions. Power flow patterns have changed between the two periods, materially for some regions. We focus on five regions with material percentage (>10%) *and* absolute (+/-25MW) changes in flows (bolded): Northland, Waikato, Hawke's Bay and Central North Island (in bold).

Table 2 Mean net flow (MWs) into simple method region per trading period

	Mean				Shares of total		
Boundary	**Period1**	**Period2**	**Change**	**% Change**	**Period1**	**Period2**	**% Change**
NLD_HV→NLD_LV	82	54	-28	-34%	2%	1%	-31%
UNI_HV→NLD_HV	126	71	-55	-44%	3%	2%	-41%
UNI_HV→UNI_LV	445	443	-2	0%	11%	11%	4%
LNI_HV→UNI_HV	1183	1156	-27	-2%	28%	29%	3%
LNI_HV→WTO_LV	133	152	19	14%	3%	4%	20%
BOP_LV→LNI_HV	11	16	5	45%	0%	0%	53%
HB_HV→HB_LV	46	43	-3	-7%	1%	1%	-2%
LNI_HV→HB_HV	146	89	-57	-39%	3%	2%	-36%
LNI_HV→CNI_LV	61	32	-29	-48%	1%	1%	-45%
LNI_HV→WTN_LV	221	226	5	2%	5%	6%	7%
USI_HV→NMB_LV	43	44	1	2%	1%	1%	7%
USI_HV→USI_LV	299	315	16	5%	7%	8%	11%
USI_HV→TIM_LV	61	60	-1	-2%	1%	2%	3%
CSI_HV→USI_HV	662	691	29	4%	16%	17%	10%
CSI_HV→WTK_LV	38	40	2	5%	1%	1%	10%
CSI_HV→CML_LV	31	37	6	19%	1%	1%	25%
LSI_HV→SLD_LV	9	1	-8	-89%	0%	0%	-88%
LSI_HV→CSI_HV	234	186	-48	-21%	6%	5%	-17%
CSI_HV→LNI_HV	352	331	-21	-6%	8%	8%	-1%
Total	**4183**	**3987**	**-196**	**-5%**	**100%**	**100%**	**0%**
Selected regions (bold)	548	398	-150	-27%	13%	10%	-24%

[20] For simple method flow measurement, Transpower uses September-August years. For this analysis, we chose July to June years as at the time of the analysis July and August data were not yet available. It is unlikely this matters much for the purpose of this analysis. We sought to replicate the regions, but the precise configuration of the 21 regions we used may differ in their detail from what Transpower used for the first simple method period.

A.6 This data suggests flows are not 'generally enduring'. But based on published simple method allocators, we also note that, for the 5 regions identified above, the impact of an extension on charges is likely to be muted because:

(a) these regions are the main beneficiaries of investments made in their own region – they will continue to be allocated most of the costs of those investments, even as offtake falls

(b) the share of these regions' simple method charges that relates to investments made in other regions tends to be small – this tempers the impact of even large reductions in shares of the cost of investments made in other regions

(c) the extra covered costs allocated for new simple method charges each year are a reducing share of total simple method charges (and total transmission charges).

A.7 To test these points, we estimated the order-of-magnitude impact of new simple method investments in the 2028 pricing year on simple method charges for the selected regions:

(a) under the original simple method allocators for the first period

(b) under revised simple method allocators that reduce the charges attributable to investments in other regions by the change in net flows.

A.8 We estimate total simple method charges will increase by $76m in the 2027 pricing year and $50m in the 2028 and 2029 pricing years.[21] In our hypothetical scenario, we assume the additional total simple method charges in those years are distributed in proportion to the distribution of charges per investment region in 2026.[22]

A.9 On this basis, we estimate an extension in simple method period 1 increases simple method charges in 2028 (and the same again in the 2029 pricing year) by a few percentage points in these regions – this is unlikely to have material negative efficiency effects in aggregate.

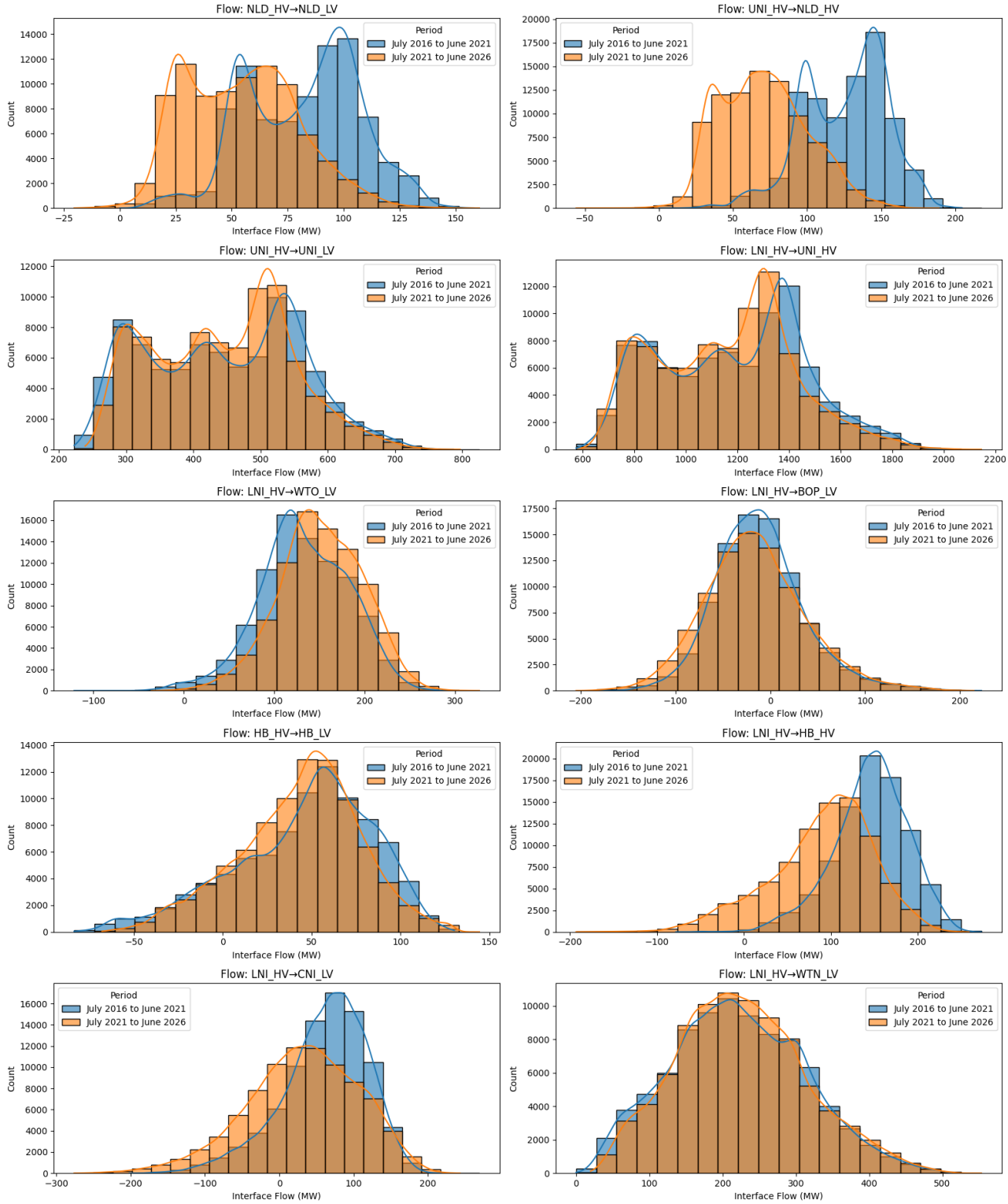
Table 3 Simple method charges in selected regions

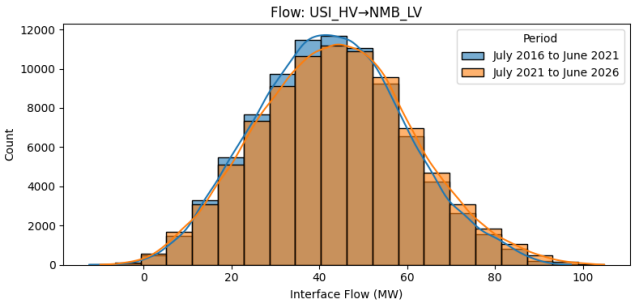
	Northland HV	Northland LV	Waikato LV	Hawkes Bay HV	Central NI LV	Total simple method charges
Δ mean net flows	-44%	-34%	14%	-39%	-48%	
Δ max net flows	-7%	2%	9%	-5%	11%	
$ Offtake in 2026	$2.0m	$4.6m	5.6m	$1.6m	$6.0m	$74m
$ Injection in 2026	-	-	$1.0m	-	$2.1m	$44m
						$118m
Order of magnitude estimates						
$ Offtake in 2027	$3.2m	$7.5m	$9.3m	$2.6m	$9.9m	$122m
$ Injection in 2027	-	-	$1.6m	-	$3.5m	$72m
						$194m
Impact of additional $50m of simple method covered costs in 2028						
If using current allocators	+$830k	+$1.9m	+$2.4m	+$670k	+$2.6m	
Est. change due to new allocators	-$150k	-$240k	+$125k	-$200k	-$210k	
Change total $2028 offtake charges	-4%	-3%	1%	-6%	-2%	
% allocation for investments in own region	82%	90% (=35%HV+55%LV)	83%	84%	90%	
% of charges from investments in other regions	17%	36%	36%	80%	17%	

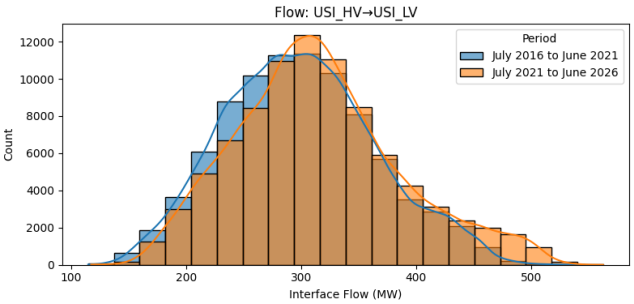
[21] These estimates are derived from Transpower's revenue model for regulatory control period 4 and Authority calculations.

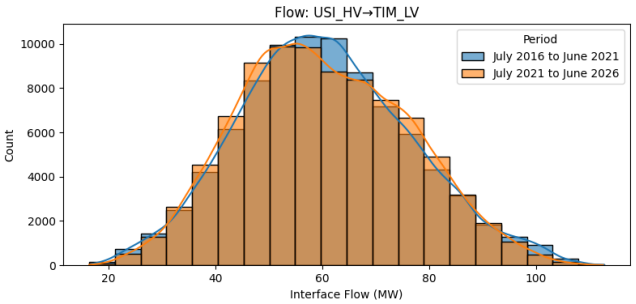
[22] As a further scenario, we also considered an alternative assumption where the additional $50m charges in 2028 would be divided equally between regions – this significantly reduces the impacts shown here, as in effect it increases the amount of investment in own regions (the costs of which are mainly allocated within the own region), reducing the covered costs allocated to investments made in other regions.

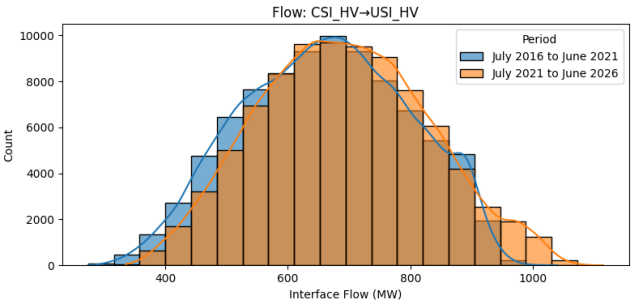
Figure 1 Histograms of net flows between regions per trading period

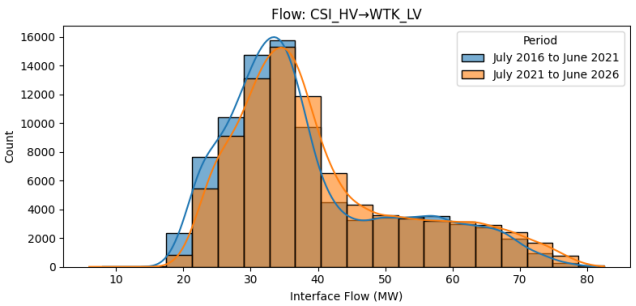


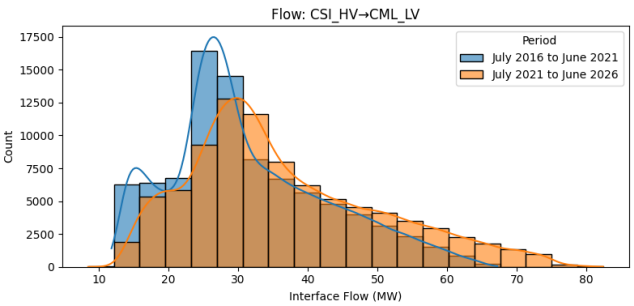

Flow: USI_HV→NMB_LV
Period
July 2016 to June 2021
July 2021 to June 2026
Count
Interface Flow (MW)

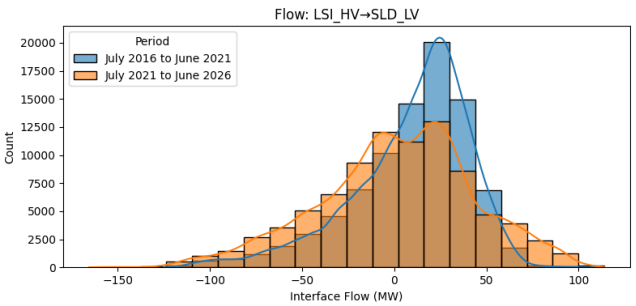

Flow: USI_HV→USI_LV
Period
July 2016 to June 2021
July 2021 to June 2026
Count
Interface Flow (MW)

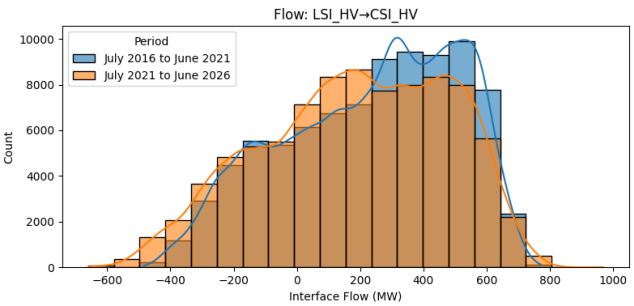

Flow: USI_HV→TIM_LV
Period
July 2016 to June 2021
July 2021 to June 2026
Count
Interface Flow (MW)

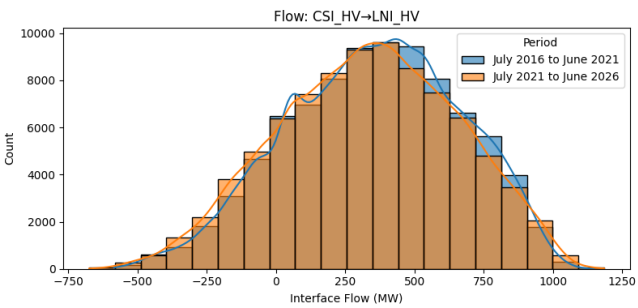

Flow: CSI_HV→USI_HV
Period
July 2016 to June 2021
July 2021 to June 2026
Count
Interface Flow (MW)


Flow: CSI_HV→WTK_LV
Period
July 2016 to June 2021
July 2021 to June 2026
Count
Interface Flow (MW)


Flow: CSI_HV→CML_LV
Period
July 2016 to June 2021
July 2021 to June 2026
Count
Interface Flow (MW)


Flow: LSI_HV→SLD_LV
Period
July 2016 to June 2021
July 2021 to June 2026
Count
Interface Flow (MW)


Flow: LSI_HV→CSI_HV
Period
July 2016 to June 2021
July 2021 to June 2026
Count
Interface Flow (MW)


Flow: CSI_HV→LNI_HV
Period
July 2016 to June 2021
July 2021 to June 2026
Count
Interface Flow (MW)

Appendix B Approved Code amendments

B.1 This appendix contains the final approved Code amendments the Authority has decided to make in response to submitter feedback and in accordance with the decisions set out in the main body of this document.

B.2 Code changes are shown as follows:

(a) text or formatting is red underlined where the consultation paper proposed it be added to the Code

(b) deleted text is ~~red strikethrough~~ where the consultation paper proposed it be deleted from the Code.

(c) text or formatting is shown in blue underlined where drafting changes were made following consultation and it is to be added to the Code

(d) deleted text is in ~~blue strikethrough~~ where drafting changes were made following consultation and it is to be deleted from the Code.

BBC simple method treatment of battery storage

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~~ **regional customer group** g is a **regional demand group** and the **customer** is a member of ~~that a~~ **regional demand group** due to its **offtake** for **battery storage**; and
(b) otherwise 1.

(1A) **Transpower** must—
(a) continue to use existing **customers' individual NPBs** calculated under subclause (1) before it was amended by the [*name of amending instrument*] until 31 March 2027; and
(b) recalculate existing **customers' individual NPBs** calculated under subclause (1) in accordance with subclause (1) as amended by the [*name of amending instrument*] with those calculations applying on and after 1 April 2027.

Anticipatory Capacity

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 post-2019 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**~~ **price-quantity 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 not more ~~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**.~~

44 Overview of Price-quantity Method

(1) Clauses 44 to 55 apply—

(a) to the **price-quantity method** only; and

(b) only to—

(i) those **post-2019 BBIs** to which **Transpower** applies the **price-quantity method** in accordance with subclause 43(2); and

(ii) **anticipatory BBIs**.

59 Overview of Simple Method

(1) Clauses 59 to 64 apply—

(a) to the **simple method** only; and

(b) only to—

(i) those **low-value post-2019 BBIs** to which **Transpower** applies the **simple method** in accordance with subclause 43(2); and

(ii) those **high–value intervening BBIs** to which **Transpower** applies the **simple method** in accordance with subclause 43(3); and

(iii) those **high-value post-2019 BBIs** to which **Transpower** applies the **simple method** in accordance with subclause 43(4A)~~.~~; ~~and~~

(iv) ~~**anticipatory BBIs**~~*[Revoked]*

Applying updated WACC without a lag

39 Covered Cost

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

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

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).

Batching

3 General Definitions

In this **transmission pricing methodology**, unless the context otherwise requires—

…

effective pricing year means~~;~~—

(a) for a **type A benefit-based charge adjustment event**, the first **pricing year** that starts after the end of the **financial year** during which **Transpower** determines the **type A benefit-based charge adjustment event** occurred; and

(b) for a **type B benefit-based charge adjustment event**, the first **pricing year** that starts after the date **Transpower** determines the **type B benefit-based charge adjustment event** occurred or will occur

type A benefit-based charge adjustment event means a **benefit-based charge adjustment event** that is not a **type B benefit-based charge adjustment event**

type B benefit-based charge adjustment event means a **benefit-based charge adjustment event** that **Transpower** determines—

(a) has occurred or will occur during the period from 1 July to 31 March immediately before the start of a **pricing year** (**pricing year** a); and

(b) can reasonably practicably be factored into **Transpower's** calculation of **transmission charges** for **pricing year** a, taking into account the time required for **Transpower** to complete its **transmission charges** assurance and approval processes before notifying **customers** of their **transmission charges** for **pricing year** a under **transmission agreements**

75 Adjustment Events

(1) Subject to subclause~~s~~ (4) ~~and (5)~~, **Transpower** determines when an **adjustment event** occurs~~is deemed to have occurred on the date **Transpower** has actual knowledge, and is reasonably satisfied, that the **adjustment event** has occurred, regardless of when the **adjustment event** actually occurred~~.

(1A) This **transmission pricing methodology**—

(a) as it was before amendment by the [*name of amending instrument*] applies to any **benefit-based charge adjustment event** that occurred or occurs before 1 April 2027~~1July 2026~~; and

(b) as it is after amendment by the [*name of amending instrument*] applies to any **benefit-based charge adjustment event** that occurred, ~~or~~ occurs or is expected to occur on or after 1 April 2027~~1 July 2026~~.

(2) Except as otherwise stated in this **transmission pricing methodology**, if an **adjustment event** occurs, **Transpower** must adjust relevant **transmission charges** from the date of the **adjustment event**, if necessary on a pro rata basis for the **event pricing year** depending on when the **adjustment event** occurred during the **event pricing year**.

(3) If **adjustment events** affecting the same **transmission charge** occur simultaneously, **Transpower** must, to the extent necessary, determine an order in which the **adjustment events** will be deemed to have occurred for the purpose of adjusting the **transmission charge**.

(4) Subject to subclauses (6) and (7), if a **pre-start adjustment event** for a **post-2019 BBI** has occurred, **Transpower** must treat the **pre-start adjustment event** as a **benefit-based charge adjustment event** that occurred or will occur at the start of the **post-2019 BBI's start pricing year** and—

(a) if **Transpower** determines it is reasonably practicable to do so, factor the **pre-start adjustment event** into its calculation of relevant **transmission charges** from the start of the **post-2019 BBI's start pricing year**; or

(b) otherwise, process the **pre-start adjustment event** as a **benefit-based charge adjustment event** in accordance with clause 81A~~during the **start pricing year**~~.

81A Timing of Adjustments for Benefit-based Charge Adjustment Events

(1) Subject to subclauses (2) and (3), for the purpose of adjusting **benefit-based charges** for ~~in response to~~ a **benefit-based charge adjustment event**, the **benefit-based charge adjustment event** is deemed to have occurred—

(a) at the start of the **benefit-based charge adjustment event's effective pricing year**; and

(b) simultaneously with all other **benefit-based charge adjustment events** deemed to have occurred at the start of that **effective pricing year**.

(2) Subclause (1) does not apply to the **benefit-based charge adjustment events** in paragraphs 81(1)(j), 81(1)(k) and 81(1)(l).

(3) For the purpose of adjusting **benefit-based charges** for ~~in response to~~ the **benefit-based charge adjustment event** in paragraph 81(1)(c), the **benefit-based charge adjustment event** is deemed to have occurred immediately for the exiting **customer** (but not for any other **customer**).

(4) To avoid doubt, subclause (3) does not apply to any notional exiting **customer**.

(5) For the purpose of applying paragraph 83(3)(d), 83(5C)(c) or 83(6)(b) or subparagraph 84(3)(a)(ii) to 2 or more **benefit-based charge adjustment events** deemed to have occurred simultaneously under subclause (1)—

(a) the variable CA in paragraph 83(3)(d), 83(5C)(c) or 83(6)(b), as applicable, is the total of all new **customers'** and notional new **customers' BBI customer allocations** for the relevant **BBI**; and

(b) the variable CA in subparagraph 84(3)(a)(ii) is the total of all notional exiting **customers' BBI customer allocations** for the relevant **BBI**.

(6) **Transpower** does not breach subclause 81(2) if —

(a) **Transpower** factors an expected **type B benefit-based charge adjustment event** into its calculation of **transmission charges** for a **pricing year**; and

(b) the expected **type B benefit-based adjustment event** does not occur on or before 31 March immediately before the start of the **pricing year**; and

(c) **Transpower** chooses to delay any incremental **benefit-based charge** attributable to the expected **type B benefit-based charge adjustment event** until **Transpower** determines it has occurred.

82 Benefit-based Charge Adjustment Event: Material Damage

(1) This clause 82 applies in the case of the **benefit-based charge adjustment event** in paragraph 81(1)(a).

(2) In this clause 82, a relevant **pricing year** is—

(a) *[Revoked]*~~the **event pricing year**; and~~

(b) each ~~subsequent~~ **pricing year** from and including the **benefit-based charge adjustment event's effective pricing year** for which a **write-down** due to the **material damage** is not reflected in the **RAB** values or **values of commissioned asset** used to calculate the **BBI's covered cost** for the **pricing year**.

(3) Subject to subclause (4), **Transpower** must, for each relevant **pricing year**—

(a) reduce the **BBI's covered cost** by an amount determined by **Transpower** to reflect a reasonable **write-down** of the **BBI** due to the **material damage**; and

(b) calculate or re-calculate (as the case may be) all **beneficiaries' benefit-based charges** for the **BBI** based on the reduction of the **BBI's covered cost** under paragraph (a).

(4) If a **beneficiary** (the causing **beneficiary**) caused, or contributed to the cause of, the **material damage**, subclause (3) does not apply to the causing **beneficiary's benefit-based charge** for the **BBI**.

(5) *[Revoked]*~~**Transpower** is not required to (but may) start a **beneficiary's monthly benefit-based charge** calculated under paragraph (3)(b) during, or from the start of, an **exempt pricing year** for the **beneficiary**. However, any over-recovery of the **BBI's covered cost** for the **exempt pricing year** (accounting for the **material damage**) must be rebated, as appropriate, to the **beneficiaries** (other than any causing **beneficiary**) by way of an adjustment to their **transmission charges** —~~

~~(a) if reasonably practicable, at the end of the **exempt pricing year**; or~~

~~(b) otherwise, as soon as reasonably practicable during the next **pricing year**.~~

(6) *[Revoked]*~~**Transpower** must not increase any **transmission charges** for the **event pricing year** as a consequence of applying subclause (3).~~

83 Benefit-based Charge Adjustment Event: New Customer

…

(10) *[Revoked]*~~**Transpower** must start the new **customer's monthly benefit-based charges** calculated under paragraph (3)(c) or (6)(c) as soon as reasonably practicable. The new **customer's monthly benefit-based charges** may include an adjustment as necessary to ensure the new **customer** pays its full **benefit-based charge** for each **BBI** from the date the new **customer** connected to the **grid**.~~

(11) *[Revoked]*~~**Transpower** is not required to (but may) start any other **beneficiary's monthly benefit-based charges** re-calculated under paragraph (3)(c) or (6)(c) during, or from the start of, an **exempt pricing year** for the **beneficiary**. However, any over-recovery of the **benefit-based charge** for a **BBI** and **exempt pricing year** resulting from the start of the new **customer's monthly benefit-based charge** for the **BBI** must be rebated, as appropriate, to the other **beneficiaries** by way of an adjustment to their **transmission charges**—~~

~~(a) if reasonably practicable, at the end of the **exempt pricing year**; or~~

~~(b) otherwise, as soon as reasonably practicable during the next **pricing year**.~~

84 Benefit-based Charge Adjustment Event: Exiting Customer

…

(3) Subject to subclause (7), **Transpower**—

(a) must, for each relevant **BBI**—

(i) make the exiting **customer's BBI customer allocation** and **benefit-based charge** for the relevant **BBI** 0; and

(ii) scale up all remaining **beneficiaries' BBI customer allocations** for the relevant **BBI** by a factor (F) calculated as follows:

$$F = \frac{1}{1 - CA}$$

where CA is the exiting **customer's BBI customer allocation** for the relevant **BBI** immediately before it was set to 0 under subparagraph (i); and

(iii) re-calculate all remaining **beneficiaries' benefit-based charges** for the relevant **BBI** based on the remaining **beneficiaries' BBI customer allocations** calculated under subparagraph (ii); and

(b) *[Revoked]*~~must not increase—~~

~~(i) the remaining **beneficiaries' benefit-based charges** for the relevant **BBI** and **event pricing year**; or~~

~~(ii) any other **transmission charges** for the **event pricing year**,~~

~~as a consequence of applying subparagraph (a)(i).~~

Removal of SSI adjustment event

3 General Definitions

In this **transmission pricing methodology**, unless the context otherwise requires—

…

substantial sustained increase *[Revoked]*~~means, for **large plant**, an increase in the **large plant's** expected annual **electricity** consumption or generation (as the case may be)—~~

~~(a) of at least 25% since the last time the relevant **customer's BBI customer allocations** for 1 or more **BBIs** were calculated, as assessed under subclause 81(4); and~~

~~(b) that is not attributable to a **large upgrade** of the **large plant**; and~~

~~(c) that **Transpower** determines is reasonably likely to persist for at least 5 years after the start of the relevant **event pricing year**~~

81 Benefit-based Charge Adjustment Events

(1) The following events are **benefit-based charge adjustment events**:

(a) a **BBI** suffers **material damage**:

(b) a new **customer** connects to the **grid**:

(c) a **customer** (the exiting **customer**) ceases to be a **customer**:

(d) an existing **customer** (the connecting or disconnecting **customer**) connects **plant** to, or disconnects **plant** from, the **grid**:

(e) **large embedded plant** is connected to, or **large embedded plant** is disconnected from, a **host customer's** (the connecting or disconnecting **customer's**) **local network** or **grid**-connected **plant**:

(f) *[Revoked]*~~there is a **substantial sustained increase** by a **customer's** (the increasing **customer's**) existing **grid** connected **plant**:~~

(g) *[Revoked]*~~there is a **substantial sustained increase** by existing **large embedded plant** connected to a **host customer's** (the increasing **customer's**) **local network** or **grid** connected **plant**:~~

(h) a **distributor** (the connecting **distributor**) connects its **local network** at a **grid point of connection** (new **grid point of connection**) to which the connecting **distributor** was not connected immediately before connecting its **local network** at the new **grid point of connection**:

(i) the **point of connection** for existing **large plant** changes:

(j) a **customer** (the vendor) sells or otherwise transfers all or part of its business that constitutes it as a **beneficiary** of a **BBI** to another party (the purchaser):

(k) **Transpower** decides to voluntarily under-recover a **BBI's covered cost**:

(l) there is a **SSCGU**.

…

(4) *[Revoked]*~~For the purposes of paragraphs (1)(f) and (1)(g), whether the increase in **electricity** consumed or generated by the **large plant** is a **substantial sustained increase** in respect of a **BBI** must be assessed against the average annual **electricity** consumption or generation by the **large plant** explicitly or implicitly included in the current value of the increasing **customer's intra-regional allocator** for its **regional customer group** and the **BBI**.~~

…

(8) Any of the **benefit-based charge adjustment events** in paragraphs (1)(b) to (1)(j) may also be a **SSCGU**, in which case both clause 91 and clause 83, 84, 85, ~~86,~~ 87 or 88 (as applicable depending on the **benefit-based charge adjustment event**) will apply. However, clause 83, 84, 85, ~~86,~~ 87 or 88 will only apply to a relevant **BBI** described in paragraph 91(2)(a) in respect of **pricing years** before the **SSCGU's start pricing year**.

~~86 Benefit-based Charge Adjustment Event: Substantial Sustained Increase~~*~~[Revoked]~~*

~~(1) This clause 86 applies in the case of the **benefit-based charge adjustment event** in paragraph 81(1)(f) or 81(1)(g).~~

(2) **Transpower** must

(a) comply with clause 83 as if the **substantial sustained increase** were attributable to **plant** connected to the **grid** by a separate new **customer** (the notional new **customer**) at

(i) if the **substantial sustained increase** is in **electricity** consumed or generated by **grid** connected **plant**, the **connection location** where the **grid** connected **plant** is connected; or

(ii) if the **substantial sustained increase** is in **electricity** consumed or generated by **large embedded plant** connected to the increasing **customer's local network**, the **connection location** electrically closest to the **large embedded plant's** electrically closest **point of connection** to the **local network**, as determined by **Transpower**; or

(iii) if the **substantial sustained increase** is in **electricity** consumed or generated by **large embedded plant** connected to the increasing **customer's grid** connected **plant**, the **connection location** where the **grid** connected **plant** is connected; and

(b) attribute the notional new **customer's BBI customer allocation** (and the inputs to its calculation) and **benefit-based charge** for each relevant **post-2019 BBI** and **Appendix A BBI** to the increasing **customer**.

Technical drafting refinements

The Authority has approved all the technical amendments proposed here, other than the addition of "high-value" to the definitions of ancillary services BBI, market BBI and reliability BBI. This is to ensure the amendment to clause 27 relating to ancillary services BBIs requiring the use of the price-quantity method also applies to any low-value BBIs.

The Authority has additionally approved the technical amendment proposed by Transpower to clause 77 here.