Proposed Transmission Pricing Methodology

Consultation paper

Submissions close: **5pm 2 December 2021**

8 October 2021

Executive summary

Proposed Transmission Pricing Methodology for your feedback

The Authority seeks feedback from interested parties on a proposed Transmission Pricing Methodology (TPM). This proposal seeks to incorporate into the Code a TPM consistent with the 2020 TPM Guidelines.

The proposed TPM reflects the significant work Transpower has undertaken over the last year. The Authority acknowledges this work and the input provided by stakeholders.

The Authority has approved for consultation the TPM that Transpower proposed largely unaltered, except for some targeted changes that we consider are needed to adequately conform with the Authority's statutory objective and will be for the long-term benefit of consumers, as explained in this paper.

It is in consumers' interest to get transmission pricing right

Most of New Zealand's electricity is generated a long way from where it is used. The national transmission grid transports electricity around the country. It gives consumers access to cheaper and more reliable electricity than if they had to rely solely on local sources, and it gives generators access to bigger markets.

Transpower currently charges about $800m per year for transmission services, about 10% of a household's total power bill. The TPM determines who pays what share of that $800m.

Transmission charges give people important signals about the cost of using the grid. Prices – including transmission charges – influence people's and businesses' use of electricity and the investments they, Transpower and others in the sector make. If transmission charges give the wrong signals, then they can distort electricity use and investments. This can result in consumers paying more than they need to. By contrast, the right signals promote competition, reliability, and the efficient operation of the electricity industry.

It is important to get transmission pricing right. This is particularly so in anticipation of significant growth in electricity demand and investment in transmission and generation that is expected in the years ahead as New Zealand transitions to a low-emissions economy. Getting the right signals in place will help ensure that this transition occurs at least cost to consumers over the long term.

We note the increased and important role distributed electricity resources will play in this transition, but under any plausible scenario grid-supplied electricity will continue to play a critical role. Poor transmission pricing risks making the transition more costly, and potentially slower, including by encouraging inefficient investment choices.

The current TPM is inefficient and no longer fit for purpose

When the Authority published the 2020 Guidelines, it noted the material cost of inefficient behaviours and outcomes caused by the current TPM. The majority of stakeholders acknowledge that there are problems with the current TPM.

Currently, the regional coincident peak demand (RCPD) charge distorts the cost of transmission. It allocates the cost of the grid based on how much people consumed at peak in the previous year, regardless of whether there are capacity constraints. That charge is recognised by many to be overly high. It causes consumers to unnecessarily reduce their demand at peak times, even if there is no congestion. It also encourages investments in distributed generation, processes and technologies simply to avoid and shift transmission charges to other parties which raises overall costs.

Another issue is that the cost of transmission assets is spread across all customers around the country (postage stamping), regardless of whom the assets serve. That makes for poor incentives on participants to make sure grid investments are the best solution to improve the capacity or reliability of that part of the electricity system. Poor incentives arise because those who would benefit from a grid investment know that most of the costs will be paid for by others – thus, they have less reason to concern themselves with grid investment processes or to explore alternative options, the costs of which may not be as widely socialised.

The high voltage direct current (HVDC) inter-island connection is paid for by South Island generation alone. This is despite North Island consumers significantly benefitting from lower electricity prices enabled by the connection, and North Island generators from being able to transport electricity to South Island consumers when hydro lake levels are low. The HVDC charge discourages investment in otherwise cheaper South Island generation and supports investment in more expensive North Island generation, which does not face equivalent charges. Ultimately this increases costs to consumers.

The current TPM is therefore not durable. The problems with the current TPM will get worse, given the projected growth in transmission costs as part of the transition to a low-emissions economy, and increasingly cheaper access to technology that allows transmission cost shifting. We expect this will also lead to increasingly volatile transmission charges if the current TPM were to remain in place. As recently demonstrated in the Ashburton region, such unpredictability could particularly impact New Zealand's key export sectors (eg, agriculture businesses with high irrigation needs). The Authority identified these issues during its process leading up to the 2020 Guidelines and concluded that the TPM needed to change.

2020 Guidelines for a new TPM

To address these issues, the Authority issued the 2020 Guidelines setting out the intent and structure for a new TPM, having considered and consulted on a long list of options over the course of a decade.

At the heart of the Guidelines is a benefit-based approach. Under this approach, those who benefit from transmission investments would pay for them. A customer or region may benefit from better energy prices and a more reliable energy supply resulting from the transmission investment, for example.

Transmission charges would also be more fixed; they would generally not change if customers change their use of the investment once it has been built. This helps to avoid incentives for participants to take inefficient actions to shift costs to others.

Benefit-based charges and a residual charge would replace the RCPD and HVDC charges. Benefit-based charges are at the core of the Guidelines and would cover grid investments made from July 2019 and the remaining costs of seven recent major grid investments.

A residual charge would recover unallocated costs and the remaining costs of all other historical transmission investments currently in place.

Existing wholesale electricity market (nodal) prices would then work alongside the new charges, providing a more accurate, responsive and targeted signal of the cost of using the grid in the absence of other distorting signals. Real-time pricing combined with emerging technologies and new business models (eg, flexibility trading) that can be very responsive to price signals are expected to make this an increasingly effective and efficient way to manage grid congestion.

The Guidelines also provide for connection charges (largely unchanged from the current TPM), a prudent discount policy, and a transitional cap to minimise any price shock to households and businesses as the new charges are introduced, reallocating costs. There is also provision for a transitional congestion charge and other additional components which Transpower must include if, in its reasonable opinion, that would better promote the Authority's statutory objective.

The Authority seeks your feedback on the proposed TPM

The proposed TPM discussed in this consultation paper largely adopts, for the purpose of consultation, the proposal that Transpower put to the Authority.

The Authority considers that the proposed TPM is consistent with the Guidelines, and that the small number of departures from the detail of the Guidelines are justified and consistent with clause 2 of the Guidelines because they better meet the Authority's statutory objective and are therefore for the long-term benefit of consumers.

Some of the key features of the proposed TPM are summarised here. A range of options has been considered for each of the components of the proposed TPM, first by Transpower and then the Authority. The material choices are set out in this paper for feedback.

Connection charge. The proposed TPM leaves connection charges largely unchanged, ie, the connecting transmission customer – a generator, industrial consumer or lines business – generally pays for the connection asset. However, the charge would no longer include an injection overhead component. The Authority considers that including such a component would not best promote its statutory objective, nor is it provided for in the Guidelines, while Transpower has suggested it is not needed given the approach to benefit-based charges.

The proposed TPM also addresses first-mover disadvantage issues which could discourage investment:

- the customer who first funds the capital cost of a connection asset would get a financial contribution from customers that connect later, through a 'funded asset component' and rebate mechanism
- where Transpower builds a connection asset with excess capacity in anticipation of (uncertain) future customers, the cost of that anticipatory capacity would be allocated to 'regional beneficiaries' until such future customers connect. This is so that these extra costs do not discourage or delay the first mover from connecting or result in under-sized connection investments due to first movers not agreeing to additional capacity. That will be particularly important in New Zealand's planned transition to a low-emissions economy which is premised on the connection of new generation and electrification of process heat.

Benefit-based charge. Under the proposed TPM, the costs of new grid investments would be allocated to the beneficiaries of those investments, rather than through the HVDC and RCPD charges.

The proposed TPM has two standard methods to allocate costs of future grid investments valued over $20m: one method for resiliency investments and another (the 'price-quantity' method) for other large investments. It also has a simple method for investments under

$20m. This threshold aligns with the Commerce Commission regime, with Transpower needing to submit proposals for major grid investments valued at over $20m to the Commission for assessment, including assessing their costs and benefits.

The Authority considers that these methods in aggregate reflect an appropriate balance between precise allocations and pragmatism (ensuring Transpower is able to sensibly apply this new approach to its numerous asset-related capital expenses across its network). In practice, the simple method captures the majority of Transpower's investment each year.

Some of the key features of the proposed benefit-based charge methodologies are:

- The price-quantity standard method uses modelled price changes (with and without the new investment) to determine regional groups of beneficiaries, and then may use either quantities during periods of benefit, or both quantities and prices, to allocate between those groups. The Authority considers that price changes are an important factor to consider when estimating benefits but acknowledges the sensitivity of price modelling for future scenarios that Transpower has encountered. The proposed TPM therefore provides two modelling options, one of which is more price-sensitive. Which option is used will depend on the nature of the investment and on Transpower's judgement as to whether outcomes will be broadly in proportion with benefits.
- For resiliency investments that specifically seek to prevent island-wide cascade failures, benefit-based charges are spread across all load customers across the island in proportion to their historical load.
- The simple method allocates charges to regions identified based on historical power flows.
- The simple method's initial allocations under the proposed TPM are split approximately 50:50 between generation and load. This is considered an appropriate starting point on the limited evidence available, but the proposed TPM requires a review of this split every five years, taking into account the allocations that resulted from at least ten standard method investments.

The benefit-based charges recover both capital and operating costs attributable to a benefit-based investment. In the proposed TPM, these covered costs include a share of overhead operating costs that Transpower considers to be reasonably attributable to benefit-based investments.

Residual charge. The residual charge recovers Transpower's remaining costs that are not recovered through other charges. This includes the remaining costs of all but seven historical transmission investments currently in place. The charge is deliberately structured to not create incentives that distort use or investment decisions, including to avoid residual charges.

The residual charge is to be paid by all transmission customers to the extent they are load customers. This includes grid-connected generators with embedded load. Initial allocations are updated over time, though with a significant lag and gradual ramp-up to minimise incentives to avoid this charge. This lag and gradual ramp-up would also apply to the residual charges of new entrants, so they are not placed at a disadvantage.

The residual charge is allocated to load customers based on final consumption of electricity. This means battery storage (including grid-connected batteries) would attract a residual charge only to the extent that it finally consumes electricity (that is, the difference between energy in and out). This approach avoids double-counting of consumption (for residual charge allocation) – which could happen if energy that is stored in a battery is deemed consumption when the battery charges up, and again deemed to be consumption when essentially the same energy is used by final consumers. Such double counting would create an extra cost for battery storage that would not be faced by other generators and so would result in a competitive disadvantage if not addressed. The proposed approach places battery storage on a more level playing field with other generation, embedded generation and cogeneration.

Adjustment to charges. As explained above, the allocators that determine customers' transmission charges are intended to be fixed. But the proposed TPM does provide for some specific circumstances in which adjustments can be made, such as when a customer enters or exits, or if there is a substantial and sustained change in grid use.

Prudent Discount Policy. The proposed prudent discount policy (PDP) allows Transpower to discount a customer's transmission charges in order to:

- avoid a customer investing in alternative projects to inefficiently bypass existing grid assets
- ensure a customer's charges do not exceed the efficient standalone costs of transmission services.

Transitional congestion charge. The Authority's view, as set out in the 2020 Decision Paper, is that wholesale electricity market nodal pricing provides an efficient market-based signal of the cost of using the grid. It therefore determined that provision for a permanent transmission peak charge was not required to manage congestion. Noting the clear distortionary impacts of the RCPD charge, the TPM Guidelines do not allow for a permanent peak charge.

However, in acknowledgement of some residual uncertainty as to how the market will respond when the RCPD charge is removed, including because real-time pricing in the wholesale market will only be implemented in late 2022, the Guidelines provided for the transitional congestion charge (TCC) as an additional component to give Transpower another tool to manage congestion.

Transpower, however, concluded that any heightened short-term congestion risk from removing the RCPD charge can be effectively and efficiently managed through the tools available to it as the system operator and grid owner, so it did not propose a TCC in its 30 June 2021 TPM proposal. The Authority agrees with its analysis. Transpower is still able to propose a TCC later via an operational review if this would better meet the Authority's statutory objective.

Impact on customers' charges

The proposed TPM means that some transmission customers would pay more and others less than they would under the current TPM at the point of transition. This is a reallocation of cost, not an increase in transmission costs, as the TPM does not change Transpower's maximum revenue when it is implemented.

In the consultation paper, we summarise Transpower's analysis of what charges might have been under the proposed TPM if it had been implemented this year, to allow comparison with customers' actual transmission charges.

There are relatively small shifts in the shares of charges between the four regions; consumers in the Upper North Island will tend to pay for a larger share compared to the other regions, as a disproportionate share of recent grid investment has been made in this region. On average across New Zealand, the proposed TPM would result in a small reduction in the average household electricity bill (0.1%), relative to what they currently pay.

In the local networks that would pay more, on average annual household electricity bills would increase by $14 as a result of the proposed TPM. In the local networks that would pay less in transmission charges, on average household electricity bills for the year would be around $19 lower as a result of the proposed TPM. Of course, these are averages: impacts will vary between local networks and for consumers within networks.

To minimise any price shock on household and business consumers, in line with the Guidelines, the proposed TPM also includes a 3.5% cap on the amount total electricity bills may increase as a direct result of bringing in the benefit-based and residual charges (after allowing for annual inflation and volume growth). However, because changes in transmission charges are modest overall, none of the local networks would have the increase in their charges limited in this way.

A number of industrial customers that are connected directly to the grid would be protected by this transitional cap on transmission charges. Their charges rise significantly. This is likely because these consumers have generally paid relatively low transmission charges to date as compared with their size and the benefits they receive from the grid. The transitional cap will provide these consumers time to adjust to the new charges. As explained later in this document, the cap phases out over time.

Indicative charges presented in this report also indicate that, due to the introduction of benefit-based charges and the removal of the HVDC charge, North Island generators would pay a somewhat larger share of total transmission charges (and South Island generators a somewhat lower share). However, over time the share of transmission charges paid by generators as a whole would increase materially under the proposed TPM.

Over time, the impact of the proposed new TPM would become more noticeable, as Transpower makes more benefit-based investments in the grid to accommodate increased generation and demand as a result of the electrification of industrial processes and transport. Increasingly transmission charges would be paid by the beneficiaries of those investments, rather than the costs being smeared across all customers, and the share of transmission charges recovered through the residual charge is projected to reduce from approximately 63% at the outset to 20% in the 2034/35 pricing year.

Assessment of costs and benefits

The Authority expects the proposed TPM will deliver significant benefits to consumers. The proposal addresses the problems with the current TPM it identified during its TPM review leading up to the Guidelines decision for the reasons set out in the Authority's earlier papers.

In particular, improved pricing would reduce the cost of consuming electricity at times when consumers value it the most and improve the signals of the cost of using the grid. Improved pricing would support the right investments being made at the right time and in the right places, and better position New Zealand for a transition to a low-emissions economy by ensuring the best use of existing and future infrastructure.

As well as its qualitative assessment, the Authority has updated its quantitative CBA to reflect the form of the proposed TPM and new information made available since its Guidelines decision. It estimates that the proposed TPM could deliver New Zealand consumers a net quantified benefit of $1.25b over the next 28 years, within a range of $0.4b-

$2.9b. This excludes unquantified benefits, which the Authority considers would be net positive and material. A key driver of these benefits is that better transmission pricing signals will result in New Zealanders being able to access new cheaper renewable generation earlier.

Next steps

This consultation marks the next stage in the development of a new TPM. The Authority now invites submissions on the proposal to incorporate the attached proposed TPM into the Code.

At this stage, the Authority expects to be in a position to make its decision on the proposed TPM by 31 March 2022, and for 1 April 2023 to be the date that new transmission prices under any new TPM would take effect.

This timing is of course subject to consideration of submissions, which could impact on content and the timing of the Authority's decision.

Submissions on the proposal are due by 5pm, Thursday **2 December 2021**, and cross-submissions will be due by 5pm on 23 December 2021. Further details are in Appendix A.

Contents

Tables

Figures

1 Purpose of this consultation document

1.1 The purpose of this document is to consult with interested parties on the Electricity Authority's proposal to replace the current Transmission Pricing Methodology (TPM) at Schedule 12.4 of the Code with the proposed TPM set out in **Appendix C**.

1.2 The proposed TPM must adequately conform with the 2020 Transmission Pricing Methodology Guidelines (Guidelines) the Authority published on 10 June 2020. This consultation document explains and seeks feedback on the proposed methodology. We note that, while this paper focuses on key issues arising out of the development of the proposed TPM, the Authority welcomes feedback on all aspects of the proposed TPM.

1.3 We refer interested parties to the Authority's 2020 Decision paper and references therein (including particularly to the 2019 Issues paper) for a detailed analysis of the problems with the current TPM, the legal framework for conducting the review, the alternative approaches considered (but not adopted) as part of addressing these problems, and the Authority's consideration of submissions that culminated in the publication of the 2020 Guidelines. This paper does not repeat this earlier material and instead focuses on the proposed TPM developed within the framework of the Guidelines.

Development of the proposed TPM

1.4 Following publication of the 2020 Guidelines, the Authority requested Transpower to develop a proposed new TPM to be submitted before or on 30 June 2021.

1.5 Transpower submitted its proposed TPM and Reasons paper on 30 June 2021. Its process included engaging with interested parties on a range of issues and considering Authority feedback on work-in-progress at specified checkpoints. Transpower published its external engagement, including checkpoint correspondence, on its website.

1.6 The Authority referred some parts of Transpower's proposal back to Transpower for further consideration and resubmission where the Authority considered the proposal did not adequately conform with the Guidelines or its statutory objective. Transpower re-submitted on these parts of its proposal on 25 August and 15 September. The Authority has subsequently considered the resubmitted proposal.

1.7 In the period after 30 June 2021, Transpower made staff available to the Authority to facilitate the Authority's understanding of the TPM that Transpower proposed, and discuss, clarify and respond to questions from the Authority regarding the TPM that it proposed, including in connection with the matters referred back to Transpower by the Authority.

1.8 Consistent with the TPM development process set out in Chapter 17 of the 2020 Decision paper and clauses 12.90 and 12.91 of the Code, the Authority has considered Transpower's proposal against the 2020 Guidelines, and the Authority's statutory objective.

1.9 In this paper the Authority sets out its proposed TPM for consultation. The proposed TPM is to a large extent based on that provided by Transpower (including as updated in its responses to the Authority's refer-back letters of July and August 2021). This reflects the Authority's agreement with most aspects of, and the reasoning behind, the TPM that Transpower proposed, although the Authority has, where appropriate, raised additional options for stakeholders to consider. Transpower's documents (its Reasons paper and responses to the Authority's refer-back letters) are therefore an important part of the reasoning for the Authority's proposal (save where this consultation paper is inconsistent with them). We have not repeated Transpower's reasons in respect of those aspects where we agree with Transpower's proposal.

1.10 The Authority has, however, amended the TPM that Transpower proposed in relation to a number of matters, in accordance with clause 12.91(2) of the Code.[1] These matters are clearly set out, including as against what Transpower proposed, and considered in this document.

1.11 The Authority has included these changes in the proposal as it considers them necessary to ensure the proposed TPM adequately conforms with the 2020 Guidelines and the Authority's statutory objective. The Authority's statutory objective at s15 of the Electricity Industry Act is to promote competition in, reliable supply by and the efficient operation of, the electricity industry for the long-term benefit of consumers. The Guidelines were developed in accordance with that objective. In making or assessing any proposal or alternative the Authority is seeking to ensure that the proposed TPM is consistent with the Guidelines and promotes its statutory objective.

1.12 The Authority expects any final TPM to be enduring. However, to ensure that it is able to endure, there should be scope for any issues to be addressed. The Code already provides that Transpower can propose a variation of the transmission pricing methodology to the Authority, provided at least 12 months have elapsed from the time the Authority approves a new TPM (clause 12.85 of the Code). The Authority is also still considering whether to progress a supporting Code amendment to allow a re-opening of any new TPM if issues arise as to its workability or promotion of the statutory objective.[2]

Making a submission

1.13 Please see **Appendix A** for details on how and by when you can make a submission on this proposal, and make any cross-submission.

1.14 Submissions are due by **5pm, Thursday 2 December 2021**.

1.15 Cross-submissions will be due by 5pm, Thursday 23 December 2021.

1.16 Please direct any questions related to this consultation to TPM@ea.govt.nz.

1.17 **Appendix B** brings together all the consultation questions set out in this document.

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1 The main areas of difference are in relation to aspects of connection charges (specifically, to address first mover disadvantage), the residual charge (application to battery storage) and adjustments (applying a lag and a gradual increase in the residual charge for a new entrant and for growth in an existing customer's load).

2 Clause 12.86 of the Code provides for the Authority to review an approved transmission pricing methodology if it considers there has been a material change in circumstances.

What happens next

1.18 The Authority will publish submissions and cross-submissions as soon as possible after the due dates (so please inform the Authority clearly if any part of your submission should not be published). It will then analyse and consider submissions.

1.19 Subject to its consideration of submissions, the Authority expects to make its decision by 31 March 2022. If the Authority decides to incorporate a new TPM into the Code, Transpower would then calculate new transmission prices based on the new TPM and engage with stakeholders before these are finalised.

1.20 The Authority expects that, if a new TPM is incorporated into the Code, Transpower would publish new transmission prices by 30 November 2022, and that new transmission prices under any new TPM would take effect on 1 April 2023, the start of the following pricing year.

Supporting information

1.21 In this consultation document, the Authority refers to Transpower's Reasons paper for detailed explanations, to avoid repetition. For the same reason we refer readers to the Authority's 2020 Decision paper, the Authority's 2019 Issues paper and supplementary consultation for detailed reasons and considerations for the Guidelines.

1.22 The following table provides links to key information that may be helpful to stakeholders in their consideration of this proposed amendment to the Code. This is because the process that led to the 2020 Guidelines considered many points, and stakeholder views on those, that are relevant to the issue of the TPM. This consultation then focuses on the proposed TPM developed under the Guidelines.

Table 1 Key sources of information relevant to this proposal

Item	Reference
2020 Guidelines	https://www.ea.govt.nz/assets/dms-assets/26/26850TPM-2020-guidelines-10-June-2020.pdf
Guidelines decision paper	https://www.ea.govt.nz/assets/dms-assets/26/26851TPM-Decision-paper-10-June-2020.pdf
Peak charges under proposed TPM Guidelines information paper	https://www.ea.govt.nz/assets/dms-assets/26/26542Peak-charges-under-proposed-TPM-guidelines-information-paper-and-next-steps-March-2020.pdf
2020 Supplementary consultation paper	https://www.ea.govt.nz/assets/dms-assets/26/26354TPM-supplementary-consultation-Feb-2020.pdf
2019 Issues paper	https://www.ea.govt.nz/assets/dms-assets/25/25466TPM-Issues-Paper-30-July-2019-full-document.pdf
Proposed TPM	**Appendix C**
Transpower's Reasons paper	TPM proposal to the Electricity Authority | Transpower

Transpower's resubmitted proposals and supporting information	https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm/tpm-proposal-electricity-authority
Transpower TPM development	https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm
Authority correspondence with Transpower on TPM development	https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/

1.23 Further relevant background related to this proposal is available on the Authority's transmission pricing review webpage at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/

2 A new TPM to give effect to the 2020 Guidelines

2020 Guidelines sought to address issues with the existing TPM

2.1 Transpower delivers the infrastructure that transports electricity from where it is generated to local lines companies and large industrial users.

2.2 The transmission pricing methodology (TPM) sets out how Transpower will recover its maximum allowable revenue from its transmission customers. The Commerce Commission determined this revenue at an average of $809 million per year between 2020 and 2025.[3] It is expected to rise to more than $1 billion per year by 2030.

2.3 In 2020, the Authority issued new TPM Guidelines for development of a proposed new TPM following a decade-long review process.[4]

2.4 This review identified evidence that the current approach to transmission pricing is causing inefficient behaviours and other outcomes inconsistent with the promotion of the Authority's statutory objective. Some issues had been present since the review of the TPM started in 2009, while rapidly changing technology and the implications of New Zealand's transition to a low-emissions economy mean other factors are becoming more pressing over time.

Existing issues

2.5 The 2020 Decision paper provides a comprehensive problem definition with respect to the existing TPM. In brief, the Authority found evidence of inefficient behaviours and outcomes caused by the current TPM, the key issues being that:

- the RCPD charge distorts the cost of using transmission. Consumers unnecessarily reduce their demand at peak times, even when there is no congestion. The charge promotes unnecessary investments in distributed generation, processes and technologies to avoid and shift transmission charges on to others. The RCPD charge is likely to get more volatile over time (due to shifting patterns of demand, eg, increased irrigation load in summer), further encouraging these behaviours
- the HVDC charge distorts the cost of South Island generation. It raises the cost of generation in the South Island, and tilts the playing field towards otherwise more expensive generation in the North Island which does not face equivalent charges
- smearing charges across the country (postage stamping) results in poor incentives to scrutinise grid investments. Those who would benefit from a grid investment know that most of the costs will be paid for by the rest of the country, so may favour this over alternative solutions, (eg, local generation, demand response).

3 Commerce Commission, *Transpower's individual price-quality path from 1 April 2020. Companion paper to final RCP3 IPP determination and information gathering notices*, Nov 2019. https://comcom.govt.nz/__data/assets/pdf_file/0035/188783/Transpower-Individual-Price-Quality-Path-from-1-April-2010-Companion-paper-to-final-RCP3-IPP-determination-and-information-gathering-notices-14-November-2019.PDF

4 See Figure 2, p11 of 2020 Decision paper

2.6 The current TPM is therefore not durable. The long-standing debates over many of these issues will get worse given the projected growth in transmission costs as part of the transition to a low-emissions economy.

Legal framework for the review of the TPM

2.7 The review of the TPM is governed by Part 12, subpart 4 of the Code. The legal framework is discussed in chapter 4 of the 2020 Decision paper.

2.8 The Authority may review an approved TPM if it considers there has been a material change in circumstance (clause 12.86).

2.9 The Authority considered that there had been a material change in circumstances since the current TPM came into force, meeting the clause 12.86 threshold. The reasons are set out in para 4.25-4.35 of the 2020 Decision paper.

2.10 The Authority published Guidelines to be followed by Transpower in developing a proposed TPM, and in its Decision paper set out the process for development and approval of that proposed TPM, in accordance with clauses 12.81 to 12.83 of the Code.

2.11 The Code provides that Transpower must submit a proposed TPM to the Authority (clause 12.88) and that this proposed TPM must be consistent with any determination under Part 4 of the Commerce Act, the Authority's statutory objective, and the Guidelines. It should also include indicative prices (clause 12.89).

Requirements from here

2.12 The Authority decided on and issued new TPM Guidelines in 2020, and Transpower has now submitted a proposed new TPM, which the Authority has considered under clause 12.91 of the Code. The process that must now be followed is set out in clauses 12.92-12.94 of the Code. This involves the Authority publishing and consulting on the proposed new TPM, considering submissions, and subsequently deciding whether to incorporate the new TPM into the Code and the date the new TPM would take effect.

2.13 In addition to the Code process, the overall process of considering whether to amend the Code, setting guidelines and developing and potentially incorporating a new TPM is further governed by the Electricity Industry Act 2010, which sets out the Authority's ability to amend the Code (section 38), and the process for consultation on proposed amendments (section 39).

2.14 Section 39(1) of the Act requires the Authority, before amending the Code, to:

- Publicise a draft of the proposed amendment. See **Appendix C.**
- Prepare and publicise a regulatory statement, which, per 39(2) must include 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. See Chapter 14.
- Consult on the proposed amendment and regulatory statement.

2.15 The Authority has included a regulatory statement at Chapter 14. However, we note that many of these issues have been addressed as part of the Authority's decision on the Guidelines. The regulatory statement therefore refers extensively to these earlier papers.

The Authority's statutory objective

2.16 As a Crown entity, the Authority must act consistently with its statutory objective, which is at s15 of the Electricity Industry Act 2010:

The objective of the Authority is to promote competition in, reliable supply by and the efficient operation of, the electricity industry for the long-term benefit of consumers.

2.17 The Authority considers the proposed new TPM is consistent with its statutory objective, and the Guidelines (or consistent with the intent of the Guidelines, where in the proposal differs from the detail of the Guidelines, as permitted under clause 2).[5]

Supporting Code amendments

2.18 The Authority is still considering the need for Code amendments on the following four subjects related to the TPM:[6]

(a) The method for allocating residual loss and constraint excess (LCE),[7] which is currently based on the existing TPM (discussed briefly below).

(b) The availability of data on activity behind the GXP to better support the effective working of the TPM (specifically the allocation of the residual charge)[8].

(c) The avoided cost of transmission (ACOT) provisions in Part 6 of the Code, which in practice are linked closely to existing transmission charges.

(d) Provision to reopen the TPM to ensure the implementation of any new TPM remains workable and continues to promote the Authority's statutory objective.[9]

2.19 These potential amendments would be consistent with the objectives of the TPM reform and the Authority expects they would likely assist with the future implementation, workability and efficiency of the proposed TPM if incorporated into the Code.

2.20 The Authority is not yet proposing Code amendments on these subjects and they are out of scope of this consultation paper. We expect to consult on whether to adopt such Code changes (if the Authority considers them necessary) within the next 12 months. Expected timing is set out in chapter 15.

2.21 For completeness, we note the Authority is reviewing the policy settings for the Financial Transmission Rights (FTR) market and the use of Loss and Constraint Excess (LCE) that supports that market. We intend to release a discussion paper later this calendar year. We are also planning to consult on how any residual LCE (ie, any LCE that is not used to support the FTR market) should be allocated, as well

5 Clause 2 of the 2020 Guidelines allows the TPM to differ in detail from the particular requirements of the Guidelines, but not the Guidelines' intent, if doing so would better meet the Authority's statutory objective than complying with the Guidelines in their entirety.

6 The Authority discussed some of these potential amendments in its 2019 Issues Paper (Appendix F).

7 LCE is otherwise known as transmission rentals, monthly settlement or congestion revenue.

8 See Transpower TPM Proposal *Reasons* paper, 30 June 2021, Chapter 16, Sections 3 and 4.

9 This could consider the change proposed by Transpower (allowing Transpower to submit a proposed variation to the TPM more frequently): See *Reasons* paper, Chapter 16, Section 2.

as its governance, principles and pass-through by distributors.[10] It will be relevant to the TPM, as LCE rebates offset transmission charges and may need to be considered by Transpower when fixing benefit-based charge (BBC) allocations.

Consultation questions

Do you have any comments on the content of this chapter?

[10] This could consider the option proposed by Transpower: See *Reasons* paper, Chapter 16, Section 5.

3 Grid asset classification

3.1 Grid assets are classified as either connection or interconnection assets. This classification determines the charges that apply to recover the costs of assets.

3.2 Grid asset classification under the proposed TPM is largely similar to that under the existing TPM.[11] That is, in general, interconnection assets are configured in a loop of continuous nodes and links (the interconnected grid) and connection assets form a link between a transmission customer's plant and the interconnected grid.

3.3 The focus of this chapter is on three areas in which the proposed TPM differs from the current TPM, as discussed below.

Relevant sections in the Guidelines and proposed TPM

Guidelines	Proposed TPM
General: Clause 11, 12, 69	Part B: Clauses 19-25
Additional components A & B: Clause viii, 54, 55	Clause 19(1), 21(3), 22(4)
Discretion to classify and reclassify clause vii(b)	Clause 25

Additional component A: Classification of grid assets during staged commissioning

3.4 The proposed TPM looks to implement Additional component A, which seeks to address any inefficient incentives for a customer to seek to avoid staged commissioning – where investments at some stages meet the definition of a connection asset, but eventually meet the definition of an investment in the interconnected grid.

3.5 Specifically, the proposed TPM requires connection assets to be treated as interconnection assets for a limited time if the assets will ultimately be interconnection assets when fully commissioned (clause 22(4)). The proposal also includes a time limit for application of the clause, to ensure there are no inefficient incentives to avoid full commissioning. For administrative reasons, this time limit is expressed as a minimum time limit of nine months from when the first node or link in the relevant group of nodes and links is commissioned.[12]

3.6 An interim classification of new grid assets as connection assets might discourage the staged commissioning of an interconnection investment, in circumstances where staged commissioning would be efficient, as customers may oppose paying connection charges in the short term. Implementation of Additional component A would remove this inefficient incentive. Consequently, the Authority considers that the proposed implementation of Additional component A is consistent with the Guidelines and would better meet the efficient operation limb of its statutory objective

11 See *Reasons* paper, Chapter 4: Part B - Grid Asset Classification

12 This is a minimum because the effective time limit is influenced by the need to align transmission charge changes with the start of a pricing year, with Transpower indicating that it will mostly be longer than this.

than not implementing it, for this reason and as otherwise set out in Transpower's Reasons paper.[13]

Additional component B: Effect of other parties connecting to grid assets

3.7 The proposed TPM implements Additional component B of the Guidelines, by including provisions to ensure that connection assets cannot be changed into interconnection assets simply by a person other than Transpower investing in other assets to create an interconnection loop (see clauses 19(1) and 21(3)).

3.8 Under these provisions any future non-Transpower links would be 'invisible' to the TPM unless Transpower agrees otherwise.

3.9 Without this provision, if a customer could change grid assets from connection to interconnection assets by constructing assets that created a loop in the grid, it would have an incentive to do so, in order to avoid paying connection charges and to share the costs amongst a wider pool of customers who might pay benefit-based charges or residual charges in relation to that investment.

3.10 The proposed implementation of Additional component B of the Guidelines would remove this inefficient incentive. Consequently, the Authority considers that the proposed implementation of Additional component B is consistent with the Guidelines and would better meet the efficient operation limb of the Authority's statutory objective than not implementing it, for this reason and as otherwise set out in Transpower's Reasons paper.[14]

Discretion to Classify and Reclassify as Connection

3.11 The proposed TPM provides Transpower with the ability to reclassify interconnection assets as connection assets in particular circumstances, ie, if the asset in substance principally provides connection services (clause 25).[15] This discretion was put forward by Transpower in its 30 June 2021 proposal to the Authority.

3.12 Transpower has identified that an unusual grid configuration in Buller Electricity's region results in some grid assets supplying a single customer being classified as interconnection assets. For the purposes of calculating indicative charges, Transpower has assumed that such assets would be reclassified under clause 25 as connection assets supplying Buller Electricity Limited.

3.13 Buller Electricity's indicative prices under the proposed TPM ($1.6m) are significantly higher than its actual 2021/22 transmission charges ($0.55m).[16] The assumed reclassification is one of the major contributors to this difference. Buller's connection charges are $17k under the current TPM, and $0.46m under the proposed TPM.

13 See *Reasons* paper, Chapter 4, Section 5.1, paras 20 - 24

14 See *Reasons* paper, Chapter 4, Section 5.2, paras 25 - 29

15 See *Reasons* paper, Chapter 4, Section 6, paras 30 - 34

16 See Chapter 12 for further discussion of Buller Electricity's indicative charges.

3.14 Transpower has stated that including this discretion is ‘a reasonable implementation of clause 11 and 12 of the Guidelines, informed by the stated purpose of Additional component B’.[17]

3.15 The Guidelines do not provide explicitly for a reclassification power in these circumstances. Clauses 11 and 12 simply require that connecting parties pay for connection assets, but do not refer to a reclassification right. Additional component B is focussed on a different and narrower problem (described above). By contrast, the proposed clause 25 reclassification power may apply in much broader circumstances.

3.16 The Authority agrees with Transpower that the definitions of connection and interconnection node, link and asset are ‘necessarily general’ and ‘may occasionally result in anomalous outcomes’ in circumstances beyond those set out in Additional component B. In our view, the connection charge provisions in the Guidelines do not necessarily prevent the proposed TPM from including a broader reclassification power. Furthermore, ensuring assets are appropriately categorised would promote efficient allocation of charges, and so the proposed reclassification power is likely to be consistent with the statutory objective. Accordingly, the Authority has decided to approve its inclusion in the proposed TPM, for the purposes of consultation.

3.17 Nevertheless, we consider this issue to be finely balanced. We are conscious some parties might be concerned the proposed TPM provides Transpower with too much discretion in this area to make changes that affect a customer’s charges. The Guidelines (at clause 1b) indicate the value of certainty – including through limiting the need for Transpower to exercise discretion.

3.18 In this case, the distinction between grid assets being a connection or an interconnection investment could have consequences for participants. Customers seeking connection investments know that they can expect to pay for them and that they alone or along with a small pool of other connection customers will be responsible for the cost whereas customers do not sign up for a grid connection with an expectation of being the only party charged for interconnection investments. Also, there may be a question as to whether it would be appropriate that the exit of one or more transmission customers could result in some interconnection assets being reclassified as connection assets for a sole remaining party.[18] Accordingly, we are seeking stakeholders’ views on this matter.

Consultation questions

Do you agree with the proposed approach to treat connection assets as interconnection assets for a limited time if the assets will ultimately be interconnection assets when fully commissioned?

Do you agree with the proposed reclassification power? Should there be any further conditions on Transpower’s use of this discretion?

Do you have any other feedback on Grid Asset Classification in the proposed TPM?

[17] See *Reasons* paper, Chapter 4, Section 6, para 34

[18] Although, note that Transpower considers that the application or not of proposed clause 25 will not turn on whether there is one or more customers connected to the grid by the interconnection asset, but rather on whether there is a realistic prospect of the asset being used to provide transmission services to a wide group of customers.

4 Connection charge

4.1 The connection charge recovers the costs of connection investments that connect a transmission customer's assets to the interconnected grid. Connection charges also recover the cost of connection alternatives. Transpower's modelling of indicative prices estimates that approximately 15% of its maximum allowable revenue would relate to connection charges ($121m in 21/22).

4.2 The 2020 TPM Guidelines by and large retained the 2006 Guidelines on connection charges, as they were considered largely consistent with efficient charging.

4.3 The proposed TPM retains many of the connection charge provisions in the current TPM, but with some 'moderate and incremental' changes.[19]

4.4 This chapter discusses these key proposed changes relevant to connection charges:

- Removal of the injection overhead component.
- Regular updating of replacement costs.
- Adding a cable line type for maintenance cost calculation.

4.5 This chapter also discusses the issues and choices with respect to addressing first mover disadvantage (including implementation of Additional component C).

Relevant sections in the Guidelines and proposed TPM

Guidelines	Proposed TPM
Clause (iii), 11, 12 connection charge	Part C: Clauses 26-35
Clause (viii), 54, 57, 64 Additional component C, F	

Injection overhead component

4.6 The connection charge in the current TPM includes a surcharge on generation customers. Its purpose is to ensure such customers contribute to overheads – given that generators do not pay the RCPD charge. The injection overhead component accounts for $11.9m of the near $32m p.a. connection charges paid by generators.

4.7 The proposed TPM does not include this injection overhead component. Transpower noted there is no longer need for an 'injection overhead component' because certain overhead operating costs would be included in benefit-based charges which also apply to injection customers.[20]

4.8 As those costs are recovered elsewhere, the Authority considers that including such a component would not be consistent with its statutory objective. We agree that the injection overhead component is not needed. We note the Guidelines do not provide for different treatment of generators and load in the setting of connection charges.[21]

19 Transpower, Connection charges consultation paper, paragraph 5

20 *Reasons* paper, Ch 5, paras 25-29.

21 Doing so via the injection overhead component would likely be inconsistent with the Guidelines clause 1(e), which provides that the proposed TPM must, as far as possible, avoid discriminating between customers, save as allowed by the Guidelines or otherwise necessary to achieve the statutory objective.

Regular updating of replacement costs for cost allocation

4.9 Under the current TPM, customers' charges vary depending on their connection capacity, although connection asset costs are pooled. The effect of the pooling is that asset costs are recovered at a constant rate over time, which reflects the services provided by the assets.

4.10 Replacement costs of connection assets determine the share of overall costs apportioned to each asset. For example, the asset cost component of a customer's connection charge at a location is determined by multiplying the connection's replacement cost by an 'asset return rate'.[22] The same approach is applied to the operating cost components of the connection charge. In effect, every customer contributes the same amount per dollar of their connection asset's replacement cost.

4.11 The proposed TPM requires replacement costs to be updated at least every five years, with the first review able to occur before the start of the first pricing year (clause 35). If the replacement costs of existing connection assets get out of date, then each customer's share of charges get out of line with the replacement cost of the assets used to connect them.

4.12 There are no particular barriers to Transpower updating the replacement costs (following an appropriate consultation process). However, Transpower notes many replacement costs have not been updated for many years.

4.13 While not provided for explicitly, providing for regular updating of replacement costs is consistent with the Guidelines in that it would help set charges in a way that reflects the costs of providing those assets. The aim is to keep a customer's connection charge broadly reflective of the cost of the asset it uses (benefits from), while balancing precision with simplicity. The updating clause would also provide connection customers with certainty that their charges would be regularly updated in line with the replacement cost of the assets used to connect them.

4.14 When Transpower consulted on this matter in September 2020, feedback was generally supportive,[23] though some submitters also questioned whether this was a priority (Meridian, Unison), or sought further detail on the impact (ENA, Northpower, Vector). MEUG considered there was no need to embed cost review in the TPM.[24]

4.15 The Authority notes that a review of replacement costs of existing connection assets may change the distribution of connection charges. Transpower estimates that perhaps 91% of connection charges may be impacted to some degree. The distributional impact cannot be determined with sufficient confidence without more detailed investigation. Instead, any impacts and how these would be managed would be a matter for the consultation that the proposed TPM provides must occur (unless the update to replacement costs is technical and uncontroversial, there is widespread support for it, or there has been adequate prior consultation).

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22 The asset return rate = [(wacc x RAB value of all connection assets) + total depreciation of all connection assets]/ total replacement cost of connection assets. However, for transmission lines, Transpower advised that maintenance rates are in $ per km and operating recovery rate is $ per switch.

23 ENA, Mercury, Meridian, Northpower, Nova, Powerco, Trustpower, Vector.

24 See Transpower's August 2020 consultation document and feedback at: https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm/tpm-development-project-connection-charges

Adding a cable line type for maintenance cost calculations

4.16 The current TPM specifies that the allocation of line maintenance costs is based on a recovery rate, with that rate based on the average maintenance cost for the line type at issue times line length for a connection asset. There are currently three line types (high voltage, other tower lines, and pole lines).

4.17 The proposed TPM adds underground cable lines as a fourth line type, as the current TPM does not recognise it as a line type for the purpose of calculating the maintenance cost component of connection charges.[25] Initially cable maintenance costs would be based on Transpower's estimates, until there was enough historical data to calculate a four-year average of actual costs.

4.18 The proposal is consistent with the Guidelines, in that allocations of maintenance cost would more closely reflect the costs and the benefits from the connection assets and provide customers certainty about how their charges would be calculated. Feedback to Transpower in September 2020 was generally supportive[26] though Vector sought more detail on the method.

Assessment

4.19 The Authority considers that the proposal to retain, with some modifications as discussed, the existing provisions for the connection charge is consistent with the Guidelines and promotes the statutory objective through impacts on:

(a) competition: broadly cost-reflective charges ensure a level playing field between existing or new participants connecting to the grid

(b) reliability: there appear to be no direct implications

(c) efficient operation: the approach to allocating charges is a broadly cost-reflective approach that balances precision with simplicity. The Authority's previous documents explain its views as to why cost-reflective charging is likely to be efficient.

First Mover Disadvantage

4.20 The proposed TPM contains provisions designed to address two issues that could otherwise lead to inefficient investment in connection assets, potentially impacting both the efficient operation and competition limbs of the Authority's statutory objective. These two issues (known as Type 1 and Type 2 FMD) are discussed below.

4.21 Both the Authority and Transpower consider there is value in proposing solutions to these FMD issues now – to get the incentives right ahead of likely material increases in electrification and new generation build.[27]

4.22 For Type 2 FMD, the Authority and Transpower differ on how to deal with the costs of building connection assets with additional capacity in excess of the needs of the initial connecting customer (the first mover). While we agree that the first mover

25 Proposed TPM clause 30(5). Page 5.9 of Transpower's *Reasons* paper.

26 ENA, Mercury, MEUG, Northpower, Nova, Orion, Powerco, Trustpower, Unison.

27 The Guidelines do not include specific provisions to address these issues – the Authority considered they would be better addressed by Transpower (including through the TPM) – see 2020 Decision paper, para 8.7. As a result, this section of this consultation paper is relatively detailed.

should not bear all the excess capacity costs, the Authority's preferred solution is to apply a simple beneficiary-pays model. Transpower's proposal was to 'pool and share' (that is, to socialise) this additional cost across all transmission customers. Both of these options and a third alternative option are discussed below.

Type 1 FMD: 'free riders' on connection investments

4.23 The Type 1 FMD issue arises if the initial transmission customer that is charged for a connection investment (the first mover) continues to bear the full cost of the connection even if other customers later connect to the asset. This may cause customers to delay their connection to avoid becoming the first mover, potentially slowing investment in new generation or in the electrification of load.

4.24 To address this, the proposed TPM contains a mechanism to collect a financial contribution from second and later connecting parties towards the capital cost of the connection investment that was funded by a first mover customer. The contribution would occur via a component added to the connection charges, paid by second and later parties, and rebated to the first mover.[28] We describe this approach as a 'funded asset component' (FAC) mechanism (see clauses 28 and 29 of the proposed TPM). Our approach aligns with the approach proposed by Transpower.

4.25 The Authority considers that the proposed FAC mechanism is consistent with the Guidelines, and its inclusion in the proposed TPM would promote the efficient operation limb of its statutory objective.[29] The proposed mechanism is relatively low-cost to implement, and by allocating costs appropriately as between the first and subsequent connecting parties, ensures their investment decisions are not distorted (eg, parties do not delay investment to avoid the connection costs they might incur as the first mover). This mechanism also promotes competition between connecting parties (eg, two generators connecting in the same region), by ensuring all parties using a connection asset pay an appropriate share of its costs.

4.26 The Authority is seeking stakeholder views on whether the FAC mechanism may introduce a competition concern in the market for generation development. This arises because the FAC payment is ultimately made to the first mover, rather than (say) to Transpower. This means that the first mover is essentially not exposed to any FAC costs for any potential additional generation it subsequently builds at the same connection point, whereas any other party would face those costs if connecting new generation to the connection funded by the first mover. This potential investment cost difference could encourage consolidation of the ownership of local generation development options. The Authority invites feedback on whether stakeholders agree there is a potential competition issue that would be significant enough to warrant modification to the proposed FAC mechanism and, if so, how it should be addressed.

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28 This could be comparable to a commercial outcome the first mover and subsequent customers might reasonably have agreed had they had the opportunity to do so at the time the first mover entered into the investment contract. Transpower's *Reasons* paper, section 10.1. We note this mechanism would occur via a reallocation of maximum allowable revenue (MAR) (meaning the first mover's transmission charges would decrease and the subsequent customer's transmission charges would increase).

29 The FAC ensures that the costs of connection investments are recovered from those connected to them, as provided for by clause 11 of the Guidelines. The Authority considers that the threshold for using Clause 2 would also be met, if it was considered that this was necessary to implement the FAC mechanism.

Type 2 FMD: 'inefficient sizing' of connection investments

4.27 The Type 2 FMD issue arises if an initial connecting customer must carry the full cost of connection capacity in excess of its own requirements, until subsequent movers connect.[30] The anticipatory capacity is being built for future, uncertain, customers. This creates uncertainty and cost for the first mover that may discourage it from agreeing to anticipatory capacity, even if building this now would be efficient (because building one bigger asset now is usually cheaper than building two smaller assets that add up to the same capacity - one now, one later).

4.28 Transpower and the Authority agree this FMD could lead to inefficiently undersized connection investments or deter connection by first movers. These effects could lead to higher transmission costs overall and could lead to businesses slowing down their electrification, or to generation investment being delayed.

4.29 In creating any mechanism to address this FMD, the Authority considers the following issues key in looking to promote our statutory objective: addressing the FMD, ensuring efficient incentives for right-sized connection capacity investments to be made over time, and ensuring the approach is feasible to implement.

4.30 We say 'right sized' because we want to ensure connecting parties (current and future) are incentivised to scrutinise planned connection investments and to reveal plans affecting necessary connection capacity. However, we are also concerned to ensure that our proposed solution does not create incentives to over-invest, or cross-subsidies in favour of new connection customers.

4.31 The potential societal cost of these outcomes may be especially high over coming decades as decarbonisation objectives rely on significant new investment in process heat and transport electrification and new renewable generation, much of which may require additional connection assets or capacity.

4.32 The *total value* of Transpower's investments, over 15 years, which the FMD issue may affect has been estimated at over $800 million.[31] At this point, neither the Authority nor Transpower is able to estimate the proportion of that cost which might relate to anticipatory capacity – we would welcome any data or views from stakeholders that would help us to better estimate the magnitude of this issue.

Proposed TPM: benefit-based approach to allocating the cost of anticipatory connection investments

4.33 To address this issue the Authority proposes a benefit-based approach to connection charges to recover costs associated with any anticipatory capacity of investments, in

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30 Transpower also considered the Type 2 FMD issue in the context of interconnection investments but decided not to include specific measures in this area in the TPM that it proposed to the Authority. See Transpower's *Reasons* paper, Chapter 5, page 5.5, paragraph 13. The Authority considers this to be appropriate, as any FMD issue is unlikely to be material in the interconnection context, where costs are allocated to all benefiting parties based on their expected future benefits from the interconnection investment (as discussed at the Authority's 2020 Decision paper, paragraph 9.23).

31 This comprises (a) over $500m of grid connection investment for generation and (b) over $300m of grid connection investment for process heat electrification. Concept, 2021, First Mover Disadvantage – How Big? September 2021. Concept's estimates are based on the Climate Change Commission (CCC)'s recent modelling of growth in new renewable generation and electrification of process heat. The CCC's modelling largely aligns with Transpower's Te Mauri Hiko demand scenarios. The estimates relate to the total value of investments in connection assets, and connected assets that could be affected by Type 2 FMD. We have not estimated the *proportion* of these that represent the *anticipatory* capacity.

order to address the Type 2 FMD issue.[32] This is included in the proposed TPM at (clauses 27 and 28), which implements Additional component C of the Guidelines. Our proposal differs from Transpower's proposal to the Authority (discussed below).

4.34 Under the proposed benefit-based approach:

(a) Costs relating to the capacity the first mover needs would be paid by that party, ie, as currently occurs.

(b) Costs relating to the anticipatory capacity could be allocated to other customers that are expected to benefit rather than to the first mover, until subsequent movers connect. To achieve this:

(i) a new class of 'anticipatory capacity benefit-based investments (BBIs)' would be created, with the covered cost to be recovered via charges being the capital costs associated with the anticipatory capacity (in essence, these costs are treated as though they are costs of a separate investment, until such time as that additional capacity is used by subsequent movers).[33] We note that, in practice, assets for anticipatory capacity (X) may be separable assets, or they may be a shared part of assets that are sized larger than the capacity (C) needed for the first mover. In this situation a cost allocation exercise might be needed to identify the costs of an asset that relate to C, and costs that relate to X[34]

(ii) the covered cost of anticipatory capacity BBIs would be allocated using the regional allocation tables Transpower will use for setting BBCs for low-cost BBIs under the BBC simple method[35]

(iii) the relevant allocators would be selected depending on whether the additional capacity is expected to be for connection of load or generation:

- if load: costs would be allocated to local and upstream generation
- if generation: costs allocated to local and downstream load.[36]

(c) after subsequent parties connect (and the anticipatory capacity is exhausted), anticipatory capacity assets are reclassified as connection assets, with their

32 The Authority envisages that in practice, for those connection investments for which the FMD issue does not arise, the current approach to cost recovery would continue to apply. This is because in most cases, the connecting parties are a reasonable proxy for the parties that benefit from a connection investment. In practice, the proposed benefit-based approach would be applied only where it is required to address a possible first mover disadvantage (FMD). And it would apply only to costs related to additional capacity costs; the capacity required by the first mover would be charged in the normal way.

33 Under the proposed approach, all investment costs relating to anticipatory investments would be recovered via the benefit-based approach. Thus, the amount to be recovered under the benefit-based approach would be calculated as Transpower's WACC multiplied by the notional RAB value of the anticipatory capacity BBI plus an allowance for depreciation.

34 We note that the Commerce Act Part 4 does not currently require separate identification by Transpower of capacity or costs relating to C and X.

35 The BBC simple method is discussed at chapter 5. This proposed approach is only one possible way of implementing Additional component C (and implements it only to a certain degree). The Authority leaves open the possibility of a different or more comprehensive application of Additional component C via a future review, if this is later judged to ultimately better meet the Authority's statutory objective.

36 In the event the additional capacity were built in anticipation of both load and generation connecting in the same location, costs could be allocated as per any other low-cost BBI investment (that is, to within-region customers, upstream generation and downstream load).

costs pooled and recovered from connected parties as per any other connection asset.[37] [38]

4.35 The Authority proposes this approach is applied for costs relating to anticipatory capacity at both new connections ('greenfields') and upgrades of connections ('brownfields').

4.36 The Authority has considered a number of concerns with the proposed benefit-based approach that have been raised by Transpower (including that it would not be appropriate to use the simple method for BBC allocation for a different purpose to that for which it was designed, and that charges for additional capacity would fall on a small number of parties – the latter issue is discussed further below under 'A complementary alternative').[39] In the Authority's view, these concerns do not invalidate the proposed approach. The Authority notes that under our approach:

(a) benefits are determined on a regional basis based on the typical pattern of electricity flow on the grid. So, the resulting allocation would be broadly in proportion to benefits[40]

(b) benefits do not require precise allocation to individual customers. When future customers connect in a region that benefits from the investment in anticipatory capacity, they will be charged on the same basis[41]

(c) benefits are determined using a robust and established methodology based on verified data. It would apply in a transparent and objective manner. It will not require subjective judgements on an asset-by-asset basis.

4.37 The Authority considers that the proposed approach is consistent with the Guidelines, and its inclusion in the proposed TPM would promote the efficient operation limb of its statutory objective.[42]

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37 Throughout this chapter, for simplicity, the arrival of the second connecting party is assumed to exhaust the anticipatory capacity. We note that this will not necessarily be the case – as the anticipatory capacity may be large enough to provide for the needs of several subsequent connecting parties. However, the proposed TPM does provide that the replacement cost would be ratcheted up over time as new customers connect and would not be reduced again if any of those parties disconnected (just as the replacement cost for any other connection investment is unaffected by parties later disconnecting).

38 We also note that if part of an asset is used pursuant to a new investment contract (NIC), then the entire asset is valued in the RAB at nil. There is currently no Input Methodology (under the Commerce Act's Part 4) to apportion the share of the value of capacity between the NIC and the RAB. This issue does not arise if the entire investment is within the RAB.

39 See Transpower's *Reasons* paper, and 25 Aug response to the Authority's refer back letter.

40 We note that the allocations for an investment under the simple method do not change when the regional allocations change between simple method periods. Transpower's view is that this means the allocations are likely to become a less reliable reflection of benefits over time. The Authority notes that this position is the same for any benefit-based investment (the allocations are intended to be fixed).

41 In the 2020 Decision paper, the Authority illustrated how the benefit-based charge applies to investments in a workable and efficient way, using an example of a grid investment to facilitate future investment in renewable generation by parties that are not yet transmission customers (see 2020 Decision paper, paragraphs 9.22 - 9.23). The illustration works in a similar way for connection investments.

42 The Authority considers that the threshold for using clause 2 would also be met, if it was considered that this was necessary to implement this approach.

4.38 Specifically, the Authority considers that this is the best solution because it addresses the Type 2 FMD issue and best promotes efficient grid investment:

(a) The first mover and second mover pay connection costs in relation to their connected capacity, so addressing the FMD (we set out above why we think this is needed to promote our statutory objective).

(b) This approach facilitates Transpower making the judgement call about whether extra capacity is needed rather than relying (in whole or in part) on the agreement of the first mover, so that under-investment is less likely.

(c) This approach provides some incentive for affected parties to disclose information and seek to help Transpower to right-size the investment (so over-investment is less likely than for the socialisation option described below).

(d) This approach is therefore less likely to involve any cross-subsidy from consumers to large connecting generators and industrials.

4.39 It is also likely to be practicable, as it is based on the proposed simple method for benefit-based allocation of the costs of grid investments valued at not more than $20 million.

4.40 The Authority has considered an enhancement to this benefit-based approach, and wider alternative options for addressing Type 2 FMD - as discussed below. The Authority prefers a benefit-based approach because it avoids spreading costs to parties who clearly don't benefit from investments, and targets costs enough to motivate identified (regional) benefiting customers to engage with Transpower and the Commerce Commission (if applicable) on the merits of additional capacity. The Authority views temporary socialisation as the next best option.

4.41 The Authority invites stakeholder views on this proposal and on the alternative approaches discussed below.

A complementary alternative: Limit how much benefit-based charges can increase

4.42 Under the proposed benefit-based approach to funding anticipatory capacity, charges for additional capacity could fall on a small number of parties, if the location of the investment means it is likely to benefit only a limited number of regions (for example, load in a downstream region such as Hawkes Bay or Northland).[43]

4.43 In general, this would be an appropriate identification of customers likely to benefit from a grid investment. However, this may not be appropriate in situations where the additional costs are disproportionately large (for example, if there was a Government initiative to establish a major renewable energy zone in a particular region and thus Transpower invested in very high capacity connection assets).[44]

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43 See Appendix E for examples. In that appendix we also discuss the possibility that in some situations, large volumes of new generation could change a region (eg, Northland) from importing to an exporting region. In these circumstances the benefits would flow to a wider group of benefiting load customers. The limit discussed in this section could be a solution to this issue. An alternative option could be to provide Transpower with discretion to adjust the allocation (where it judged that large volumes of new generation would likely have this effect) to include the nearest major load centre, (eg, Auckland).

44 This concern was also raised with the Authority by Transpower, see Transpower's *Reasons* paper, and 25 August response to the Authority's refer back letter.

4.44 To address this potential situation, the Authority has considered:

(a) a limit above which the approach would not apply and

(b) a different method for allocating excess capacity costs for when that limit is surpassed.

4.45 Under this alternative, the benefit-based approach would not apply where additional capacity costs are unusually large. If this alternative was adopted, an upper limit would be established: the benefit-based approach would not apply for allocating costs above the limit. The limit could be defined in terms of the expected impact of excess capacity costs on transmission charges (eg, if the allocation would result in a more-than-10% increase in an individual customer's charges, or a consumer group's charges).[45] A further alternative could be defining the limit in terms of the relative size of the anticipatory capacity to the first mover's connection capacity (eg, if anticipatory capacity is greater than one third of the first mover's connection capacity).[46]

4.46 Under this alternative, we would propose 'above limit' costs could revert to falling on the first mover.[47] Possible alternative options for 'above limit' cost allocation include recovering those costs via:

(a) the standard BBC allocation method (this could be for the whole cost, not just the above limit costs)

(b) reverting to Transpower's preference for socialisation via the connection charge under its pool and share option, or alternatively via the residual charge.

4.47 The Authority invites feedback on this alternative: the merits of a limit, how that limit should be defined, and how costs above that limit should be allocated.

4.48 Finally, we note that in seeking to address the FMD Type 2 issue the Authority is limited to proposing solutions within the TPM. Where additional costs are unusually large, such as if local or central government was seeking to promote a specific renewable energy zone for generators, it may be more appropriate that the cost of additional capacity is funded outside of the TPM. That would ultimately be a question for local or central government to consider.

Alternative: Pool and share the costs relating to anticipatory investments

4.49 An alternative option for addressing Type 2 FMD is to recover costs relating to anticipatory investments from all transmission customers, in proportion to a customer's existing connection capacity. The 'pooling and sharing' would only last until subsequent movers take up the anticipatory capacity. This 'pool and share'

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45 We would also consider charge-increase-based limits other than 10%, such as 5% or 20%. Focussing on impacts on individual customers would be optimal, however it may be more practical to consider changes instead in terms of:

- asset recovery rate for the socialisation and temporary socialisation options, ie, connection charges
- consumer group for the regional benefiting customers option – where generation and load by region defines the consumer groups, eg, Northland LV load and Hawkes Bay LV generation are examples of consumer groups.

46 We would also consider capacity-ratio limits other than one third, such as 25%, 50% or 100%.

47 We note that, in practice, there may be options to address the FMD problem which exist outside of the TPM and which might avoid the first mover incurring all of the additional cost. However, as discussed below, this is a question for eg, local and central government.

approach has been proposed by Transpower.[48] Transpower's approach would effectively result in socialisation of the extra costs across all customers.

4.50 Pool and share would address the Type 2 FMD issue and has the advantage of simplicity of implementation (it does not require benefit-based allocation or tracking).[49] This option does address many of the issues that the Authority is concerned about, ie, it removes disincentives to connect, and incentives to undersize the connection asset.

4.51 As 'pool and share' is not consistent with clause 11 of the Guidelines (which sets out the general guidance for connection charges), Transpower relied on the use of clause 2 of the Guidelines to propose an approach that differed in its details from the requirements of clause 11.[50] [51]

4.52 The Authority does not consider pool and share would best meet our statutory objective, as it risks leading to inefficient investment. Consistent with the Authority's broader rationale for applying a beneficiary-pays approach to the interconnection assets, we are concerned that socialisation of the excess capacity costs would essentially promote over-investment due to a lack of any real incentives for scrutiny of proposed investments in anticipatory capacity.[52] [53] Inefficient investment leads to relatively higher electricity prices, which would hamper the electrification of the economy. Fully socialising these costs also runs the risk of essentially creating a cross-subsidy from all consumers, including residential consumers, to large new connecting parties (for the most part generators and large industrial plant).[54]

4.53 For these reasons, if Transpower's pool and share approach were to be adopted, the Authority considers that it would likely be appropriate to put further provisions into the proposed TPM around how it could be used. This could include requirements on how Transpower would establish the circumstances in which a special FMD allocation rule would apply (to mitigate the risk that the FMD solution is applied more broadly or

48 Transpower's 30 June 2021 *Reasons* paper, section 10.2, Decision Part 1 refer back: Transpower's response (25 August 2021), page 8-9

49 Transpower also discussed (but did not propose) another possibility, which involves temporary under-recovery, then socialisation in the next regulatory control period (RCP). This was described by Transpower in its *Reasons* paper as a 'default' that would occur if Xs no longer fell onto the first mover (but were unable to be recovered from other parties during the current RCP). In the absence of a second connecting party arriving, costs could remain unrecovered by Transpower until the end of the current regulatory control period (RCP), then flow into the Economic Valuation (EV) account, so roll into the next RCP's allowable revenue. Transpower also note that tracking payments is an extension that could be added onto its proposed 'pool and share' approach.

50 *Reasons* paper, para 58, paras 71-72

51 There is also a potential question as to whether such an approach is consistent with the Authority's intent provision for the connection charge, although some variation on this approach, (for example, recovery via the residual charge) may well be consistent.

52 The Authority is concerned to ensure that sufficient incentives exist for stakeholders to scrutinise proposals for transmission investments and to submit information that is relevant to proposed grid investments and potential transmission alternatives to Transpower and to the Commerce Commission (helping to address the well-known problem of information asymmetry). This is in part why the TPM Guidelines adopt a benefit-based approach to interconnection investment. See the Authority's 2020 Decision paper.

53 The Authority notes that Transpower does not agree with this concern.

54 The Authority notes that Transpower considers that the Authority's preferred benefit-based approach is effectively a more narrow socialisation approach. Regardless of how the approaches are labelled, the Authority considers that where possible a more targeted cost allocation is preferable.

more frequently than is appropriate). For example, specific consultation obligations focussed on cost and risk associated with the additional capacity costs.

Alternative: Temporary socialisation

4.54 Another alternative option for addressing Type 2 FMD the Authority has considered is temporary socialisation. This allows a first mover to defer payments for excess capacity costs until it has either finished paying for its own capacity requirements, or until a second mover has arrived to share the cost of the connection investment.[55] The second mover then contributes to the payments.

4.55 This approach mitigates the Type 2 FMD issue without permanently socialising the additional capacity costs: it presents a more attractive cashflow profile to the first mover (while leaving it with some risk) and does not deter entry by the second mover.

4.56 A challenge for this option is that it does not eliminate second-mover risk for the first mover, so may leave the FMD issue unresolved for the most risk-averse first movers (as they could ultimately end up paying the full cost of the asset, albeit over a longer period, if the second mover does not appear).[56] This outcome is different to the outcome for the other options considered, which remove all of this downside risk, and is the principal reason why this alternative was not preferred.[57]

4.57 On the other hand, requiring the first mover to bear some (substantially smaller, and delayed) risk could be an advantage of the option. Removing all risk of the first mover paying for the additional capacity would mean the additional capacity has possible benefits but no costs to the first mover.[58] This position may distort the first mover's incentives (eg, encourage it to propose more capacity than would be efficient, or conceal its true capacity requirements). Leaving the first mover with some 'skin in the game' could lead to more efficient incentives (the first mover has an incentive to challenge a proposal to build additional capacity that would likely not be required).

Alternative: Brownfield-only

4.58 The Authority's proposed benefit-based approach potentially applies to any connection investment for which the Type 2 FMD issue arises. However, another alternative option the Authority has considered is to restrict the application of the proposed benefit-based approach to brownfield investments (investments to upgrade existing connection investments). That would mean excluding investments in new connection capacity ('greenfields' investments), the building of which is potentially subject to competition.[59]

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55 Charges during the deferral phase are the same as Transpower's socialisation proposal (10 years), but with a tracking account for the first mover's deferred payments. The tracking account adds an interest charge on the outstanding balance each year, and is fully paid back over the same timeframe as the deferral. The maximum duration of deferral phase is 10 years, which matches the typical NIC duration.

56 Transpower, TPM Proposal 30 June 2021, Decision Part 1 refer-back: Transpower's response (25 August 2021), page 8.

57 Also, additional capacity costs could remain socialised if the first mover exits before the payback phase.

58 The benefit is that the first mover has the upside potential of reduced transmission charges when a second mover arrives and shares the connection costs. Or it could use the additional capacity itself.

59 Greenfields investments are typically funded outside the TPM, through a commercial 'new investment contract' (NIC) between the customer and either Transpower or another provider. Investments in greenfields capacity are subject to competition from non-Transpower providers who are able to build

4.59 Arguably, a regulatory solution to the FMD issue is unnecessary for greenfields connections, which are not always built by Transpower, as alternative commercial providers are able to make appropriate risk-return trade-offs in agreements with connecting customers, so there are incentives to invest efficiently. That is, such a provider would have a commercial incentive to build the additional capacity if additional customers were likely to connect in future but would not have such an incentive where future connections were unlikely. This is efficient.

4.60 Applying a benefit-based approach to recover the costs of additional capacity for greenfields investments could adversely affect the relatively new competition for building connection assets – as the regulated funding would provide Transpower with a competitive advantage over commercial providers. On the other hand, it is unclear how significant the scope for competition is in greenfields developments: we are aware of only a handful of potential providers and examples of competitive construction (for example, Mercury's Turitea wind farm).

4.61 The Authority is also aware of the risk that potential commercial providers, if closely aligned to the connecting party, might have incentives not to build capacity that competitors of the connecting party might use (particularly competing generation).

4.62 The Authority does not currently prefer the alternative of limiting FMD provisions to brownfield investments because, compared to competition in building connection assets in greenfield sites – the potential for which may be rather limited – we currently place greater weight on efficient investment. The latter may be promoted by ensuring the correct incentives on participants to (a) encourage them to connect at the right time and place and (b) provide Transpower with the right information. It may also be better promoted if Transpower – rather than a conflicted potential competitor – makes the final decision about whether to build extra capacity and, if so, how much.[60]

Consultation questions

Do you agree that the proposed TPM should specify that connection asset replacement values be regularly updated to promote cost-reflective charges and certainty?

Do you have any comment on the proposed approaches to address first mover disadvantage issues, including on the:

- proposed FAC mechanism for Type 1 FMD
- alternative option of an upper limit on application of the benefit-based approach for Type 2 FMD
- approach to applying 'above-limit costs' under this alternative option?

Do you have any other feedback on the proposed TPM in relation to connection charges?

these connection assets. By contrast, 'brownfields' investments can be constructed only by Transpower and are always funded as part of Transpower's regulated asset base and subject to the TPM.

60 The Authority notes that Transpower does not support this brownfields-only alternative.

5 Benefit-based charge: allocation

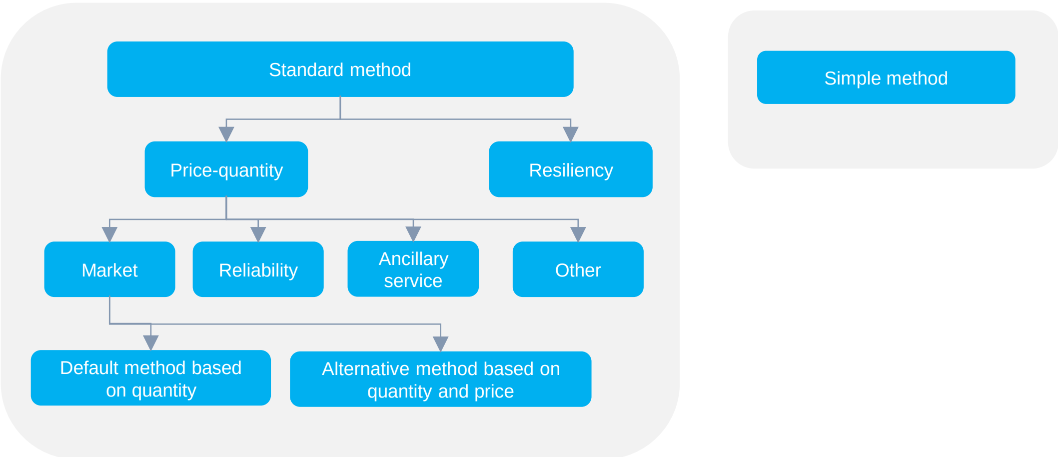
5.1 The benefit-based charge (BBC) recovers the costs of grid investments from those transmission customers expected to benefit from them, in proportion to customers' positive net private benefits, as expected at the time of setting the charge.[61] The BBC applies to all grid investments made from July 2019 and the remaining costs of seven recent major grid investments.[62] It will recover approximately 22% of grid costs initially, however, this proportion is expected to rise to 65% by 2035. The BBC will replace the RCPD charge as the primary means by which Transpower recovers the costs of the interconnected grid.[63]

5.2 Benefit-based charges are intended to promote more efficient investment by transmission customers and increase scrutiny of proposed transmission investments. Consumers who would benefit and end up paying for a grid investment would have a greater interest in having a say on that investment, to make sure it is fit for purpose and better than alternative solutions. This should result in better information for Transpower and the Commerce Commission on grid investment proposals, and solutions to capacity issues that best meet the needs, at the lowest cost, of the affected transmission customers. It should also discourage customers from proposing or supporting projects that benefit them but are inefficient and supported only because they would largely be paid for by other customers.

5.3 The proposed TPM provides for the following benefit-based allocation methods (which are also set out in the figure below):

(a) Two standard methods to allocate costs of grid investments valued over $20m (a price-quantity standard method and a resiliency standard method).[64]

(b) A simple method for investments valued at under $20m.[65]



61 Benefits from transmission investments may include better energy prices and reliable energy supply. See *2019 Issues paper*, paragraphs B.101–B.167.

62 The Authority determined the benefit-based allocations for seven historical investments as part of the Guidelines. See the Authority's 2020 Decision paper.

63 See *Reasons* paper, Appendix B, Figure 7, p B.18, and chapter 12 on indicative pricing.

64 The proposed TPM includes transitional arrangements for BBC standard method allocation. These are discussed in Chapter 15 of this paper.

65 See *Reasons* paper, Chapter 7, Section16.

5.4 The simple method is expected to be used to allocate over half of benefit-based charges. By 2035, of the projected 65% of overall charges relating to benefit-based charges, 36 percentage points are projected to relate to low-value investments allocated based on the simple method and 29 percentage points relate to high-value investments.[66]

Relevant sections in the Guidelines and proposed TPM

Guidelines	Proposed TPM
Clause iv, 8, 13-26	Part D: Clauses 36-68

5.5 The Authority considers the proposed BBC provisions submitted by Transpower to the Authority on 15 September 2021 are consistent with the Guidelines, including because they can be expected to result in cost allocations that are broadly in proportion to benefits – and are therefore consistent with the statutory objective.[67] The methodologies, and reasoning for the various design choices, are set out fully in Transpower's Reasons paper and its response to the Authority's request that it reconsider some aspects of the proposal submitted on 30 June 2021.[68]

5.6 However, in addition to feedback on these aspects of the proposed TPM in general, the Authority is seeking feedback on a number of specific issues (outlined below) relating to the proposed allocation methods that we want to test specifically with stakeholders. This chapter also discusses the issues and choices with respect to addressing Additional component E of the Guidelines (which relates to extending the application of benefit-based charging to more pre-2019 grid investments).

Price-quantity standard method

5.7 The price-quantity method (clauses 45-54 of the proposed TPM) quantifies benefits using price-quantity modelling aligned with that required by the Capex IM.[69] The price-quantity method is used to assess four classes of benefits but market benefits are generally expected to be the class of benefits from new transmission investments that is modelled most frequently.[70]

5.8 There are two (sub-) methods for assessing market benefits, set out in clauses 52 and 53 of the proposed TPM respectively. Under both of these, regional groups of beneficiaries are determined based on modelled price changes (using scenarios with and without the new investment). Benefits are allocated between regional groups of beneficiaries under the clause 52 method based on the quantity of load or generation

66 High-value investments can be further broken down into post-2019 investments (18%) and pre-2019 investments, (ie, Schedule 1 benefit-based charges) (11%). For a full breakdown of projected charges refer to chapter 12.

67 For the reasons noted in paragraph 2 of this chapter and set out more fully in the 2019 Issues paper and the 2020 Decision paper on the Guidelines.

68 See Transpower's 15 September 2021 submission to the Authority (responding to the Authority's refer-back decision Part 2 set out in its letter to Transpower dated 18 August 2021).

69 See *Reasons* paper, Chapter 7: Part D - Benefit-based charge allocation methodology, section 4.1

70 There are three other benefit classes for which benefits are derived via the price-quantity relationship: ancillary service benefits (clause 54); reliability benefits (clause 55); and other benefits (clause 56).

during periods of benefit. Modelled prices are also used to allocate between regional groups of beneficiaries (that is, the clause 53 method is used) if Transpower concludes that quantity alone would not result in an allocation that is broadly proportional to expected positive net private benefits. Benefits are allocated to load or generation customers within a region based on allocators that vary depending on the type of benefits (eg, market benefits) and on whether the investment is driven by peak demand or not.[71] Transpower may make further adjustments if necessary to ensure allocations reflect benefits, under both the clause 52 and clause 53 methods.[72]

5.9 To illustrate the application of the price-quantity method, Transpower provided the CUWLP (Clutha and Upper Waitaki Lines Project) case study.[73] Transpower has also prepared an addendum, that explains how the changes that have been made to the TPM that it proposed since its 30 June proposal impact the case study.[74]

5.10 In general, the Authority considers that the proposed price-quantity standard method can be expected to result in cost allocations that are broadly in proportion to benefits – and so is consistent with the Guidelines and with the Authority's statutory objective. The Authority is interested in stakeholders' views on any aspect of this proposed standard method.

5.11 In addition, there are two specific issues relating to the assessment of market benefits in the price-quantity standard method that we want to test with stakeholders:

(a) Criteria for use of clause 52 vs clause 53 methods.

(b) Definition of regions and customer groupings.

Criteria for use of clause 52 vs clause 53 methods

5.12 As noted above, the price-quantity method for market benefits includes two sub-methods: [75]

(a) A default method that calculates market regional net private benefits largely based on quantity (clause 52), using the modelled price dimension to define beneficiary regions and groups but not to allocate benefits between benefiting customers. Rather, quantities alone are used for this latter step.

(b) An alternative method that calculates market regional net private benefits based on quantity and price (clause 53), using the modelled price dimension

[71] See *Reasons* paper, from page 7.58, from paragraph 232 (section 14).

[72] See clause.50(5) of the proposed TPM. As part of the Authority's assessment we considered the possible risk that by providing too much discretion to Transpower, clause 50(5) could lead to charges that do not reflect benefit, such as by leading to an inefficient socialisation of investment costs. The Authority considers this risk can be appropriately managed by Transpower transparently disclosing information on its approach to these adjustments (in the Assumptions handbook and via consultation). Appendix F sets out an example of a situation where an adjustment to prices could be appropriate under the price-quantity standard method.

[73] *Reasons* paper, Appendix D: BBC Price-quantity method case study – CUWLP.

[74] Transpower, Addendum to CUWLP case study following Refer Back response 28 September 2021

[75] See Appendix F for further information on why both a default allocation method (clause 52) and an alternative allocation method (clause 53) are required for standard method investments with market benefits.

(as well as quantities) to define beneficiary regions and groups and also to determine the relative benefits between benefitting customers.

5.13 The Authority has considered whether, because the proposed clause 52 method does not rely on modelled price changes to allocate benefits between benefiting customers, it might fail to capture an important driver of the benefits of a grid investment. However, the proposed TPM also provides that if the proposed clause 52 method would not result in an allocation that is broadly proportional to benefits, then the clause 53 method would be used.

5.14 The Authority has also considered the related question of whether the proposed TPM might allow too much discretion to Transpower in selecting which of the two methods to use.[76] Limiting the need for Transpower to exercise discretion in setting charges can promote certainty for industry stakeholders – as the Authority recognised in the TPM Guidelines.[77] Subsequently the Authority referred this point back to Transpower, who considered and addressed the issue (by including the criteria noted below).

5.15 Following Transpower's resubmission, the proposed TPM includes criteria that limit the need for Transpower to exercise discretion in two specific situations (relating to investments where most of the benefits to supply groups are to new generating plant and that enable consumers to avoid scarcity prices).[78] The Authority considers that these criteria will appropriately limit Transpower's discretion in the situations to which they apply and give greater assurance that BBC allocations will be broadly in proportion to expected positive net private benefits.

5.16 The criterion at clause 53(1)(b)(i) is particularly important, requiring that the clause 53 method will be used if most of the benefits of an investment relate to consumers avoiding paying a high cost for electricity during peak demand periods, eg, due to a lack of transmission and generation capacity to supply load in a region. The Authority considers this situation to be one in which price is likely to be a more important driver of benefits than in most other situations, so price-related benefits should drive the allocation of the costs of such investments. The Authority considers that with the addition of these criteria the proposed TPM is consistent with the Guidelines or the Authority's statutory objective, but it is interested in stakeholder feedback as to whether the criteria are appropriate and whether there are any others which should be included.

Definition of regions and customer groupings

5.17 The proposed TPM provides rules for determining modelled regions and regional customer groups for assessing market benefits under the price-quantity method.[79] These regions identify the customers who benefit from the investments (before charges are allocated to individual customers within those regions). A robust approach to identifying regions is therefore critical to ensure that allocations are broadly in proportion to expected net private benefits.

76 Because it would be up to Transpower to assess whether the clause 52 method would result in allocations which are broadly proportional, which requires a level of judgement.

77 Guidelines clause 1(b)(iii).

78 Transpower, 15 September 2021 Part 2 refer back: Transpower's response, Section 2

79 Clause 51 applies to determining the modelled regions (and regional customer groups) for both clauses 52 and 53.

5.18 The Authority has considered whether the proposed approach to regions is appropriate. If regions and customer groups are too broad (eg, encompass different customers with widely divergent benefits from an investment), they would not result in an allocation that was broadly proportional to benefits for at least some of those customers.

5.19 The proposed TPM's approach to defining regions (in clause 51) considers important constraints elsewhere in the grid (in particular, the HVDC) when determining the number of regions (in addition to considering the constraint relieved by the grid investment and the direction of modelled price changes).[80] The Authority considers that this achieves an appropriate balance between certainty (clause 1(b)(iii) of the Guidelines) and flexibility to produce allocations that are broadly in proportion to benefits (clauses 8 and 21 of the Guidelines), and therefore supports the statutory objective. The Authority considers that the benefits of greater precision are likely to exceed any additional cost of administering the default method (and may avoid any unnecessary additional cost of using the more complex clause 53 method). The Authority is interested in stakeholder feedback as to the proposed TPM's approach to the definition of regions and customer groups.

Resiliency standard method

5.20 The resiliency method (clauses 57-59 of the proposed TPM) will apply for a sub-set of BBIs that are primarily needed to mitigate high-impact, low probability risks such as a cascading outage that could result in an island-wide black-out. To illustrate the application of the resiliency method, Transpower provided the WUNIVM (Waikato and Upper North Island Voltage Management project) case study.

5.21 For BBIs that are primarily intended to mitigate cascade failure,[81] the method allocates costs to offtake customers across the entire island in which the system event is being mitigated, (eg, the North Island) in proportion to their historical load.[82]

5.22 The Authority has considered whether this could create the risk of inappropriate socialisation of investment costs, eg, if investments with material non-resiliency benefits are classified as resiliency investments, or other resiliency investments are inappropriately categorised as being primarily intended to avoid cascade failure.

5.23 The Authority considers that this risk is unlikely to be material, and that the risk that allocations do not appropriately reflect benefits is mitigated by the following:

(a) The high-value investments that risk being misclassified as resiliency investments are likely to be major capex or listed projects. As part of its proposal evaluation, the Commerce Commission scrutinises whether the

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80 Transpower, 15 September 2021, TPM Proposal 30 June 2021 Decision Part 2 refer back: Transpower's response, Section 3.

81 The method also applies to BBIs that are primarily undertaken to avoid a high-impact, low probability event affecting a smaller region, for which Transpower would determine the region being affected and allocate BBCs to all offtake customers in that region in proportion to their historical offtake.

82 Transpower has proposed, and the Authority agrees, that resiliency benefits should not be combined with other benefit classes under the proposed TPM. For resiliency BBIs, benefits and regional beneficiaries are determined based solely on these resiliency benefits, rather than considering also other standard method benefit classes, (ie, reliability, market, ancillary service benefits, and "other" benefits). Therefore, if Transpower determines that resiliency benefits are the primary driver, non-resiliency benefits would not be assessed. The allocation of charges would be based solely on the resiliency method.

investment need is robustly justified, such as whether the need to avoid cascade failure is made out. For high-value projects greater than $20m undertaken as part of base capex, the extent to which these are primarily needed for resiliency reasons would likely be considered as part of the Commission's assessment of Transpower's base capex proposal.

(b) Transpower has advised that it expects very few BBIs to use clause 57 (the resiliency benefits method), and of these, only a subset would be for the purpose of mitigating cascade failure (resulting in the benefits and costs being spread across the North or South Island).

5.24 In general, the Authority considers that the proposed resiliency method can be expected to result in cost allocations that are broadly in proportion to benefits – and so is consistent with the Guidelines and with the Authority's statutory objective.

5.25 However, the Authority is interested in stakeholders' views on whether additional safeguards are required in the proposed TPM to ensure the resiliency method is appropriately applied and reflects benefits and, if so, what these should be.[83]

Simple method

5.26 The simple method (proposed TPM, clauses 60-68) allocates charges to regions identified based on historical power flows, and to individual customers within regions in proportion to their share of a region's injection or offtake over a five-year period.[84]

5.27 In general, the Authority considers that the proposed simple method can be expected to result in cost allocations that are broadly in proportion to benefits for major beneficiaries – and so is consistent with the Guidelines and with the Authority's statutory objective. The Authority is interested in stakeholders' views on any aspect of the proposed simple method. In addition, there are two specific issues relating to the proposed simple method that we want to test with stakeholders:

(a) Flow-based regional allocation.

(b) The weighting factor that determines the proportion of investment recovered from load and generation customers.

Flow-based regional allocation

5.28 The simple method in the proposed TPM estimates benefits of investments in a given region based on historical patterns of grid flow between regions.[85] It does not attempt to assess the particular benefits of individual investments. Estimated benefits are based on volume of electricity offtake/injection, not on price. The Authority has

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83 As part of ensuring the new TPM works together effectively with the input methodologies that apply under Part 4 of the Commerce Act, the Authority may engage with the Commission to clarify some of the rules and processes where Part 4 and the TPM complement each other. The Authority may do this, for example, by submitting to the Commission's forthcoming IM review consultation, so that the Commission may consider the Authority's submission as part of its review. Transpower and the Authority may also discuss with the Commission how the customer charge information disclosure templates may evolve to accommodate any new TPM. If the proposed TPM becomes part of the Code, the Commission must take it into account before exercising any of its powers or performing any of its functions under Part 4 in accordance with section 54V(4) of the Commerce Act.

84 See *Reasons* paper, Chapter 7, Section 16.

85 As part of the Authority's assessment of the simple method we considered which customers (in which regions) will pay the costs of a given dollar of investment in each investment region. Appendix F contains charts illustrating the regional allocation of charges under the simple method.

considered whether, because the proposed simple method (like the clause 52 method) does not use price to allocate benefits, it might fail to capture an important driver of the benefits of an investment.

5.29 The Guidelines require that the simple allocation method involves lower administrative costs to quantify benefits (compared to the standard method) and results in an allocation between major beneficiaries that is *broadly* in proportion to benefits. Further, the Guidelines at clause 1(b) require that the proposed TPM balances the economic benefits and costs of precision against practical considerations including robustness, simplicity, certainty and implementation cost.

5.30 The Authority considers that the proposed flow-based regional allocation approach is consistent with the Guidelines and with the Authority's statutory objective. This approach assumes the distribution of benefits from grid investment reflects the pattern of electricity flow: an investment tends to benefit customers located within the region in which it is made as well as upstream generation and downstream load. This assumption is reasonable for low-value investments. It is appropriate for the simple method to focus on flows and it need not take price effects into account. This is because it needs to be capable of allocating the costs of a large volume of (generally) routine lifecycle investments (eg, local tower painting). A more sophisticated method is unlikely to be cost-effective and unlikely to materially improve the precision of the allocations to beneficiaries. In the Authority's view the simple method strikes an appropriate balance between precision and practical considerations, is administratively workable and results in an allocation broadly in proportion to benefits.

Weighting of benefits between load and generation customers

5.31 A key feature of the proposed simple method is the use of a weighting factor that determines the split of charge allocations for low-value BBIs between aggregate load and generation customer groups. The Guidelines require that the allocation between major beneficiaries is broadly in proportion to benefits so any weighting factor must ultimately result in charges consistent with this provision.

5.32 Transpower has proposed a weighting factor that is broadly 50:50 between load and generation.[86]

5.33 The proposed TPM also requires a review, (and update, if appropriate) of this weighting factor every five years.[87] The first review would go ahead if the allocations resulting from at least ten standard method investments are available.[88] As the standard method involves greater granularity than the simple method, it is expected that data on these allocations will provide sound evidence to determine whether the broadly 50:50% weighting factor remains appropriate or a change is required.

86 *Reasons* paper, page 7.76). In practice, based on Transpower's indicative pricing the shares are approximately 53% to load and 47% to generation.

87 Once the benefits of a particular BBI have been allocated by the simple method they do not change, except as a result of the adjustments provisions (so under the proposal a 50:50 split would be largely locked in for the lifetime of assets valued at less than $20m commissioned from 2019 - 2028).

88 Transpower expects to produce (in draft or final form) allocations for 10 to 15 high-value benefit-based investments by the end of the first 'simple method period' which starts in July 2019 and is expected to finish at the end of pricing year 2027/28 (based on a start of a new TPM on 1 April 2023).

5.34 The Authority has investigated whether the proposed weighting factor is appropriate as a starting point, including by providing Transpower with analysis,[89] which suggested that an allocation in the range of 20–30% to generation might better reflect the benefits generation would receive from investments (relative to load).[90] In response Transpower considered a range of evidence, including the Authority's analysis, and concluded that a roughly equal load:generation split provided by the proposed proportional allocation approach for the simple method is within the range of estimates derived from the analysis and is a reasonable starting point.[91]

5.35 The Authority has accepted Transpower's assessment for consultation purposes, because we do not have strong evidence for moving away from Transpower's proposed weighting factor, and because we consider that the proposed periodic review of the weighting will be an effective mechanism for assessing and adjusting the weighting factor over time. This is because it would be based on standard method assessments of benefit-based investments. The Authority considers that the proposed broadly 50:50 weighting is likely appropriate in the interim, until that review is undertaken.

5.36 The Authority notes that the CBA supports a higher weighting to load customers.[92] The CBA scenario which assumes a weighting factor of 75% to load and 25% to generation from the outset indicates materially higher net benefits than a scenario in which the weighting remains at 50:50 over the full 28 years being assessed ($2.4b vs $1.25b).

5.37 However, there are other considerations at play, for example, it is important for the efficient operation of the electricity market, including given durability considerations, that all customers', including generators', charges are broadly in proportion to the benefits they receive from transmission investments.[93] Ultimately, what is a reasonable weighting factor is an empirical matter, and such empirical evidence will be provided through standard method assessments of high-value benefit-based investments.

5.38 The Authority also notes that the CBA is only one factor and is of course subject to limitations. In this case, empirical evidence as to the appropriate weighting, derived from the standard method assessments, is expected to be available within five years. As such, the Authority considers that waiting for that evidence from standard method assessments may be justified. Switching to, say, a 75:25 weighting factor if that is found to be a more reasonable allocation at the first five-year review point, would still yield near $2.4b in net benefits (see Appendix D). Thus, even if a 75:25 weighting factor were ultimately found to be empirically the appropriate option, the costs of

89 Annex to appendix B to the Authority's resubmission feedback letter: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/46.%2024%20May%202021%20-%20Letter%20from%20EA%20%28Transpower%20TPM%20Checkpoint%202B%20resubmission%20Appendix%20A-D%29.pdf

90 Some of this evidence indicated a lower allocation to generation of around 15% might be appropriate.

91 *Reasons* paper, Chapter 7, paragraphs 324 to 334.

92 These CBA effects arise as when generation bears higher costs, investors delay investment in generation until wholesale electricity prices have risen sufficiently to recover such additional costs.

93 If the weighting factor results in inefficient allocations, then this could distort future generation investment.

waiting until the five-year review to implement this threshold would be relatively small. It may well be that the review identifies a different weighting factor.

5.39 Overall, the Authority considers that the currently available evidence is not strong enough to depart from Transpower's proposal and adopt an alternative weighting factor for the proposed TPM. If evidence at the five-year review point indicates a different weighting is more reflective of benefits, the weighting can be adjusted then - which would achieve the additional benefits indicated by the CBA.

5.40 On this basis, the proposed TPM is based on an initial weighting factor of approximately 50%. The Authority considers that the proposed weighting factor is consistent with the Guidelines.

5.41 However, this is a finely balanced decision and the Authority is conscious of the potential long-term effect. Given the uncertainty, we would welcome submissions and further clear and robust evidence to substantiate any particular weighting factor, and the materiality of this factor for decisions on investment in generation.

Pricing impact of alternative weighting scenarios

5.42 To illustrate the impact of the weighting factors on indicative prices, we have modelled estimated charges for the first five years of any new TPM.[94] The figure below compares simple method charges (top row) and the percentage of transmission revenue (bottom row) allocated via the simple method under two load:generation weighting scenarios:

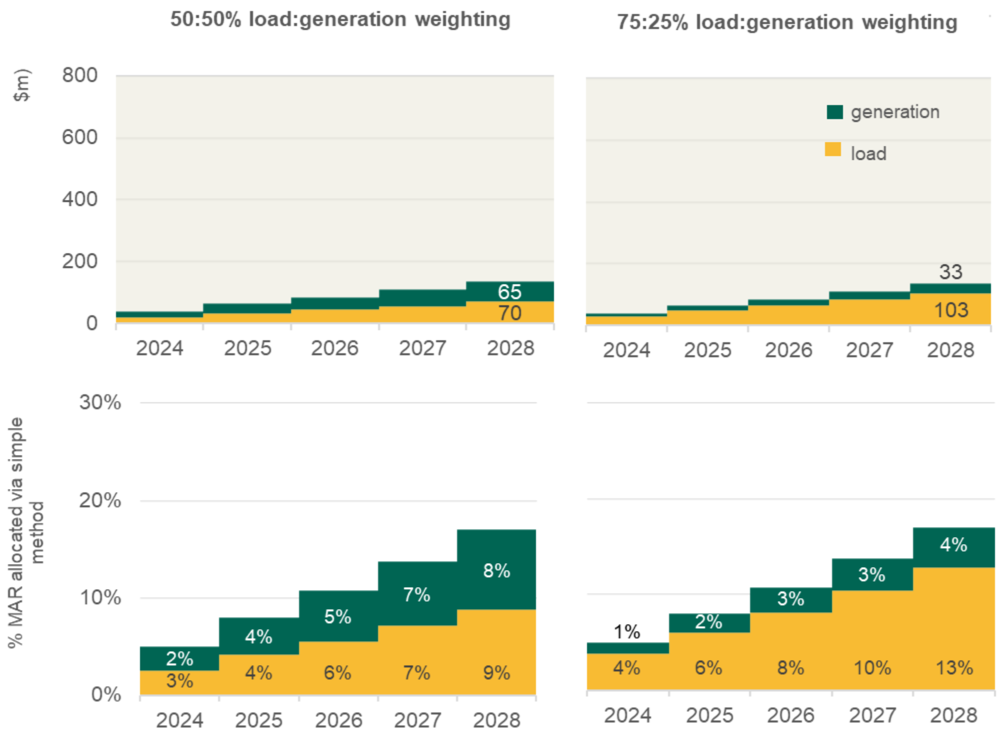
(a) 50:50%, ie, the proposed TPM;[95]

(b) 75:25%, an alternative option.

94 The modelling makes simplifying assumptions, including that the maximum allowable revenue stays constant at 2021/22 levels ($798m), and that the regional base capex is constant and equal to the average of the actual/planned base capex for the RCP3 period (2020 to 2025).

95 In this document we sometimes use 50:50 as an approximation for the load:generation weighting factor for the simple method in the proposed TPM. The actual modelled weighting factor for the simple method is 53% for load customers and 47% for generation customers.

Figure 1 Illustration of simple method load:generation weighting factor proposal and alternative scenario



5.43 When any new TPM is implemented in 2023/24, approximately 5% of the MAR or $40m would be allocated via the simple method. Under the proposed TPM (50:50% weighting) about 2% would be paid by generators and 3% by load customers.

5.44 The difference between allocation scenarios differs significantly by the end of the five-year period. Whereas under the proposed TPM (50:50% weighting) generators would pay 8% of simple method BBCs ($65m), under a 75:25% weighting their share would be only to 4% of simple method BBCs ($33m).

5.45 The figures do not extend beyond the first period as this would require further assumptions regarding the findings from a first review of the weighting factor. Whatever the outcome from the review, the simple method BBIs allocated during the first simple method period would not change, since any changes to the weighting only apply to subsequent investments.[96]

Alternative options for review of weighting factor

5.46 The Authority considers it important to ensure the five-yearly review of the weighting factor is objective and robust – noting that the weighting factor is an unusually important assumption as it appears to drive significant changes in net benefits to consumers according to the modelling from the CBA.

96 The first period allocation becomes less and less relevant as these assets reach the end of their useful lives and are replaced with new assets based on the weighting factors that apply at the time. In addition, charges relating to the first period simple method BBI would reflect changes in opex over time, and changes in regulatory input assumptions such as the regulatory WACC.

5.47 Accordingly, the Authority is considering potential enhancements to the approach in the proposed TPM, including:

(a) Requiring Transpower to consult early on a review methodology, (eg, to be included in the assumptions book in year three of the proposed TPM) which is then applied in year four of a simple method period.

(b) Providing for a formal role for the Authority or another independent party in a review. For example:

(i) Transpower could be required to formally consult with the Authority on the weighting factors.

(ii) Transpower could commission (by itself or jointly with the Authority) an independent reviewer of weighting factors (with a duty of care to both Transpower and the Authority) to review and provide recommendations.

(iii) The weighting factor could be for the Authority to determine (based on a proposal by Transpower).

5.48 These potential enhancements could increase administration costs, but could also help to ensure the five-yearly review of the weighting factor is objective and robust:

(a) An early consultation on the review methodology could ensure that stakeholder views and evidence are taken into account and so help to improve the robustness of the review methodology.

(b) Involvement of the Authority or an independent reviewer could help to ensure that the five-yearly review of the weighting factor is objective and impartial.

5.49 The Authority has not proposed these potential enhancements at this stage because it is not clear that the benefits would outweigh the cost. However, the Authority would be interested in hearing from stakeholders on this point.

Additional component E: including additional pre-2019 investments in the benefit-based charge

5.50 The Guidelines' Additional component E would extend the application of benefit-based charging to other pre-2019 benefit-based investments in addition to the seven major investments specified in Schedule 1 of the Guidelines, if that would better achieve the Authority's statutory objective.

5.51 The proposed TPM does not implement Additional component E of the Guidelines, consistent with Transpower's proposal, because the cost of implementing it is expected to outweigh the benefits.[97] The Authority considers that this conclusion would still hold even if a simple allocation method was used to implement Additional component E (such as the BBC simple method). That is because, even using a simple allocation method, there would still be significant administrative costs involved in applying the method to all remaining historical grid investments,[98] and the benefits

97 See *Reasons* paper, Chapter 14, paras 16-17.

98 Costs involved in applying the method to all remaining historical grid investments could include significant financial costs, including the costs of determining the investments subject to this component, system enhancement for the fixed asset register, external audit and detailed accounting analysis of detailed financial asset records. Regarding the latter, we note that there is likely to be less information available for other historical grid investments, relative to the Schedule 1 projects, which were large projects with likely a higher standard of project documentation.

of doing so are not expected to be substantial. Relative to post-2019 investments, there are fewer efficiencies (in terms of use and investment incentives) to be gained from accurately allocating benefit-based charges to pre-2019 investments, given these investment costs have been sunk.[99]

5.52 The Authority considers that this position is consistent with the Guidelines and with the Authority's statutory objective. The Guidelines require Transpower to balance the benefits of accuracy against various practical issues including the costs associated with developing, administering and complying with a new TPM.

5.53 Nevertheless, we note that even if Additional component E is not included in a new TPM from the outset, it could still be implemented at a later date.[100]

Consultation questions

Do you have comments on the proposed standard and simple benefit-based allocation methods?

Do you have any comment or evidence on the proposed weighting of benefits between load and generation customers under the simple method, or on the proposed review of the allocation?

99 Nevertheless, the Authority considers that the BBC should apply to the seven major investments specified in Schedule 1 of the Guidelines – for the reasons explained in the 2019 Issues paper and the 2020 Decision paper on the TPM Guidelines, ie, given the level of undepreciated cost remaining for these investments, it is problematic for their costs to continue to be spread nationwide when under the new TPM regional beneficiaries will be paying their fully allocated share of new investments.

100 For example, at the time a new large investment is made, that could provide an opportunity to implement Additional component E in respect of existing assets located in a similar area to the large investment (potentially with benefits in the same proportions as the new investment).

6 Benefit-based charge: covered costs

6.1 To implement a beneficiary-pays approach, the proposed TPM must first specify the costs that are to be recovered through benefit-based charges – the covered costs. A BBI's covered cost comprises capital charges, depreciation and operating costs, and other costs attributable to the BBI.[101]

Relevant sections in the Guidelines and proposed TPM

Guidelines	Proposed TPM
Clause 15 to 17	Clauses 40-42
Clause (viii), 54, and 64 Additional component F: method for allocating opex.	

6.2 The Authority considers that the provisions on BBC covered cost in the proposed TPM are within a spectrum of options that are consistent with the Guidelines.[102] The Authority therefore considers the covered cost provisions, in conjunction with the proposed provisions on BBC allocation, can be expected to result in cost-reflective BBCs, better scrutiny of proposed grid investment, and so more efficient investment. The proposal is therefore consistent with the statutory objective.

6.3 The reasoning for the covered cost provisions is set out in detail in Transpower's Reasons paper and its response to the Authority's request that it reconsider some aspects of the proposal submitted on 30 June 2021.[103]

6.4 In addition to seeking feedback on these aspects of the proposed covered cost provisions of the proposed TPM in general, the Authority is also seeking feedback on a number of specific issues (outlined below) that we want to test with stakeholders. This chapter also discusses Transpower's choice to not incorporate Additional component F of the Guidelines (which relates to the allocation of opex) into its proposed TPM.

Recovery of overhead opex

Proposed approach

6.5 Under the proposed TPM, overhead opex (for example, head office staff costs) is recovered through BBCs. By contrast, non-network capex (for example, the cost of furniture in Transpower's corporate headquarters) is recovered through the residual charge.[104]

6.6 The Authority considers that there is a spectrum of options that are consistent with the Guidelines, which provide that operating costs (as defined in Transpower's input methodologies as costs relating to the supply of electricity transmission costs but

101 Other costs attributable to the BBI include taxes.

102 Transpower submitted a revised TPM proposal (including provisions on covered cost) to the Authority on 15 September 2021, as part of its response to the Authority's refer-back decision Part 2.

103 See *Reasons* paper Chapter 6, and Transpower's 25 August 2021 submission to the Authority (responding to the Authority's refer-back decision Part 1 set out in its letter to Transpower dated 28 July 2021) and Transpower's 15 September 2021 submission to the Authority (responding to the Authority's refer-back decision Part 2 set out in its letter to Transpower dated 18 August 2021).

104 Transpower estimates that approximately $70m of the $450m indicative pricing residual charges relate to the recovery of non-network assets capital costs.

excluding costs such as those treated as a cost of assets, pass-through and recoverable costs) 'reasonably attributable' to the BBI should form part of its covered cost. As overhead opex can likely be considered 'reasonably attributable' to benefit-based investments (as discussed below), it is included in the covered cost for BBIs.[105] The Authority's view is that this position will likely result in all the costs that are reasonably attributable to an investment being recovered from the beneficiaries, ie, result in cost-reflective BBCs – although we welcome submissions on this.

6.7 Transpower considers a cost to be 'reasonably attributable' to a BBI if its allocation to the BBI is 'objectively justifiable', and in this regard notes that 'all of our investments and services, including BBIs, contribute in some way to our overhead opex.'[106]

6.8 The Authority consider this to be a reasonable position. For example, we would expect that a small proportion of the working hours of Transpower's head office staff is spent on (for example) the CUWLP investment. When a new grid investment is undertaken, the need for staffing costs may expand. If the CUWLP investment were not being undertaken, Transpower's staffing costs would most likely be lower. It follows that it is justifiable to attribute some proportion of those staffing costs to the CUWLP investment (and to other investments). The same reasoning applies to other overhead opex.

Alternative option

6.9 The Authority also considered an alternative approach whereby overhead opex, for which a closer direct or causal relationship with the BBI cannot be verified, is recovered through the residual charge. This was the approach the Authority had previously considered may be preferable.[107] This approach could be implemented by modifying the definition of operating cost included in benefits-based charges (clause 41(3)).[108]

6.10 Arguably, this approach is also consistent with the Guidelines. That is, overhead opex could arguably be considered not to be 'reasonably attributable' to benefit-based investments. This differing interpretation is possible because the phrase "reasonably attributable" is a relatively flexible allocation concept, so various alternative approaches may be consistent with the Guidelines. The question is then what is consistent with the Authority's statutory objective.

6.11 Arguably, this alternative approach could be consistent with the Authority's statutory objective, as it reduces the costs placed onto generation. The Authority continues to be concerned with the risk of causing adverse effects when generation must bear

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105 See clause 15(c) of the Guidelines.

106 See *Reasons* paper, page 6.8, para 21, 23

107 For example, see the 2019 Issues paper, paragraph B.73. See also the Authority's 28 July 2021 Refer-back Part 1 letter to Transpower, page 3.

108 The clause could be modified to provide that the operating costs included in benefit-based charges are equal to Transpower's allowance for operating costs minus Transpower's estimate of overhead opex, where that estimate is to take into account any cost categories agreed between Transpower and the Commerce Commission prior to each regulatory price control (RCP). Since the new TPM would begin in the current regulatory control period, a definition for the initial period could be based on RCP3 regulatory expenditure categories.

additional cost, as it can postpone investment in generation, reduce competition and lead to higher wholesale electricity prices over time.[109]

Discussion

6.12 The Authority has considered these options in light of the CBA results. The net benefits in a scenario in which overhead opex is recovered through the residual charge are higher than for the proposal (in which overheads are recovered via BBCs) by $321m over 28 years using the weighted mean, and lower by $24m using the median measure. Those measures are much influenced by sensitivities, particularly at the lower end of the distribution, and for the majority of sensitivities there is very little difference between whether overhead opex is in benefit-based or residual charges. (See Figure 23 in Appendix D).

6.13 This finding reflects that the amounts involved each year are relatively small, and thus the impact on a per customer basis may not be substantial. We note that including overheads in the BBC would make a relatively small change in (for example) Meridian's operating expenses (less than 0.5% of opex).[110] These numbers appear small in comparison with other factors that typically affect investment decisions.[111] The Authority does not have sufficient evidence to form a view that these costs are large enough to be considered material by investors.

6.14 Further, the Authority considers that generation must bear the cost of investments that it benefits from. As noted above, when all of the costs of an investment – including reasonably attributable overhead opex – are recovered from the beneficiaries (including generation), this can be expected to result in cost-reflective BBCs. In conjunction with the proposed provisions on BBC allocation, this will improve scrutiny of proposed grid investment and so lead to more efficient investment.[112] So it is consistent with the statutory objective.

6.15 Therefore, this issue turns on where to draw the boundary around the costs reasonably attributable to a grid investment. In the Authority's view, the position Transpower has proposed (that is, recovery of overhead opex – but not non-network capex – through the BBC) is within a range of acceptable options.

6.16 That said, the Authority considers the alternative option (overheads in residual charge) also has merits.[113] This is a finely balanced decision and there is uncertainty, so any robust evidence which shows that an alternative approach better meets the Guidelines and better promotes the statutory purpose – including evidence

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109 This was explained at paragraph B.224 of the 2019 Issues paper.

110 Meridian's transmission charges would be approximately $4m lower under the alternative option in the 2021/22 indicative prices. Over time the charges recovered through benefit-based charges are expected to increase. This would increase the benefit of the alternative option for Meridian (and other generators), reducing charges by approximately $10m in 2034/35. With operating expenses of $3.6bn in 2021 and $2.6bn in 2020, including overheads in the BBC would Meridian's total opex by between 0.16% (in 2021) and 0.4% (in 2035). See Meridian, Integrated Report 2021, page 115 www.meridianenergy.co.nz/assets/Investors/Reports-and-presentations/Annual-results-and-reports/2021/2021-Meridian-Integrated-Report.pdf

111 For example, Meridian, Integrated Report 2021, page 131 www.meridianenergy.co.nz/assets/Investors/Reports-and-presentations/Annual-results-and-reports/2021/2021-Meridian-Integrated-Report.pdf

112 This is discussed further at paragraph 5.2.

113 As set out in the Authority's Part 1 refer-back.

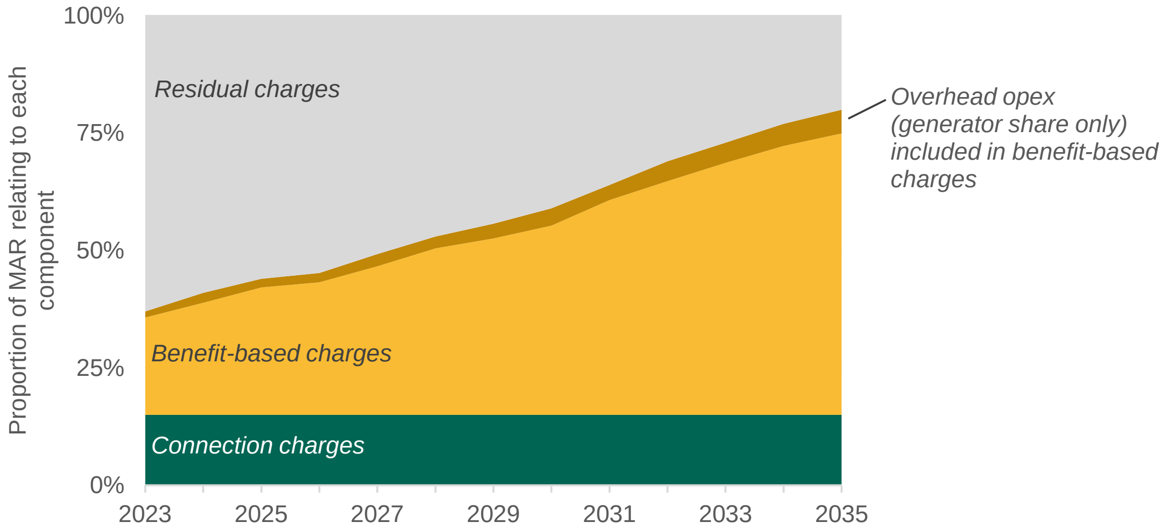
on the materiality of including these overhead costs in BBCs for generation investment decisions – would be helpful.

Impact

6.17 The impact on overall charges of this alternative option would be modest when a new TPM was first implemented but is expected to grow over time.

6.18 Below is an estimate of the overhead opex component (dark orange) paid by generators under the proposed TPM and how it is expected to trend over the next decade. The overhead opex component under the alternative option is removed from benefit-based charges (paid by both generation and load customers), and instead included in the residual charge (which is paid only by load customers).[114]

Figure 2 Estimate of overhead opex component 2023-2035



6.19 As residual charges are only paid by customers to the extent that they are load customers, the share of transmission costs recovered from generators would be lower if overhead costs were recovered solely via the residual charge, and higher for load customers. The additional amount recovered from load customers under the alternative option would be about $7m per year initially, increasing to about $21m by 2035.[115] Approximately 40% of overhead opex is estimated to be recovered from generators under the proposed TPM.

Opex for fully depreciated assets that remain in use

6.20 A number of assets in Transpower's regulatory asset base (RAB) are fully depreciated.[116] Transpower estimates that approximately 15% of opex is attributable to grid assets in Transpower's RAB that are fully depreciated but remain used and

114 To be clear, the overhead opex component under the alternative option is also removed from benefit-based charges for load customers, and instead included in the residual charge (which is paid only by load customers). However, this does not affect incidence of charges as much (as it is a shift from load customers to load customers), so we have focused on the shift from generation to load in the chart.

115 This illustration adopts Transpower's definition of overhead opex, which comprises business support opex, ICT opex and insurance opex.

116 At least initially, Transpower expects expect few of its fully depreciated assets to be associated with the Schedule 1 BBIs.

useful to provide transmission services. While fully depreciated assets do not require a return on or of capital, they do require opex (given that they remain in use).[117]

6.21 Under the proposed TPM, opex attributable to fully depreciated BBIs will be recovered through the residual charge.

6.22 The Authority considers that this proposal is consistent with the Guidelines and its statutory objective. Transpower holds only basic data on these assets. The proposed approach to allocating opex relating to these assets appropriately balances precision with practical considerations, in particular cost-effectiveness.[118] A more detailed assessment of assets that are fully depreciated might result in a refined estimate of the proportion of opex relating to these assets, which could potentially result in an more precise allocation that better reflects benefits.[119] But the cost of such an assessment would likely be substantial, so any improvement in precision would be unlikely to be cost-effective. The proposed recovery through the residual charge avoids providing undesirable incentives (as provided for in clause v of the Guidelines) which might arise if these material costs were allocated in a distortionary way.

6.23 An alternative option would be to allocate a portion of opex relating to fully depreciated assets to all customers rather than recovering all these costs through the residual charge (which is only paid by load customers). This could be implemented by applying an allocation based on the BBC simple method. However, given Transpower only holds basic information on these assets, we are not certain that this approach would reflect net private benefits (hence the Authority's proposal to recover these costs through the residual charge).

6.24 We invite stakeholders to consider the merits of this alternative option.

Additional component F: allocation of opex

6.25 Additional component F would attribute opex to the asset it was spent on (without reliance on broad allocation rules), on the basis that this could result in charges that better reflect actual costs and so promote efficient operation of the industry.

6.26 The proposed TPM does not implement Additional component F: allocation of opex. This is on the basis that any potential efficiency benefits are not justified by the 'practical difficulties, and associated expense, of directly attributing all opex categories to BBIs'.[120] The Authority accepts Transpower's view, based on its experience, in this regard.

6.27 The Authority considers that this position is consistent with the Guidelines and its statutory objective, as Additional component F should only be implemented if to do so

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117 The majority of assets comprised in BBIs will require 30 to 40 years to fully depreciate, and Transpower expects most of them to be partially or fully replaced by new BBIs at the end of their expected lives, or to have their covered cost increased through replacement or refurbishment investment. In future, Transpower does not expect there to be a significant number of fully depreciated assets in its RAB that remain in use and are not replicated by other assets in the RAB that are not fully depreciated. If this proves incorrect, Transpower indicated it would consider a future operational review of the TPM to address the issue. See *Reasons* paper, Chapter 7, para 35.

118 See clause 1(b) of the Guidelines.

119 The improved precision would result from a different amount of opex, (ie, more or less than 15%) being recovered via the residual charge, and therefore a different amount of opex would be recovered through benefit-based charges.

120 See *Reasons* paper, page 6.13

would better meet the Authority's statutory objective (which includes the promotion of efficient operation of the industry).[121] The proposal not to implement Additional component F is also consistent with the principle in clause 1(b) of the Guidelines (which relates to practical considerations, including balancing the benefits of precision against the benefits of simplicity and the costs of compliance).

Consultation questions

Do you have any comment on the proposed approach to covered costs, including on:

- whether overhead opex should be recovered through the BBC or residual charge, and any evidence to support your view?
- the recovery of opex on fully depreciated assets through the residual charge?

121 See 2020 Decision paper, paragraph 14.35

7 Residual charge

7.1 The residual charge recovers any of Transpower's recoverable revenue not gathered through other transmission charges, in a manner that least affects transmission customers' decision-making.

7.2 The residual charge would, for example, recover costs associated with:

(a) non-network capex

(b) historical investments other than the 7 named in Schedule 1 of the Guidelines

(c) any increase or decrease in other charges as a result of the application of adjustment provisions, (eg, as a result of a reassignment).

(d) any revenue which would otherwise be lost by the application of prudent discounts (to the extent it is not otherwise recovered).

7.3 The proposed application of the residual charge to battery storage is also considered in this chapter.

Relevant sections in the Guidelines and proposed TPM

Guidelines	Proposed TPM
Clause v of Authority's Intent	Part E: Clauses 69-75 of the proposed TPM
Clauses 27-30	the defined term battery storage
	Clause 5(1), 5(2) and 5(6) concerning load customers, gross energy and maximum gross demand

General provisions

7.4 The proposed provisions for the residual charge reflect the Guidelines.

7.5 Residual charges are to be paid by all transmission customers to the extent they are load customers. The allocation is fixed-like (based on each customer's historical gross anytime maximum demand, averaged across four financial years starting 2014-2017). The reasons for this approach are set out in the Authority's earlier papers.

7.6 The initial allocations are updated annually, based on changes in customers' lagged four-year rolling average of gross energy usage,[122] with this four-year period commencing the financial year eight years prior.[123]

7.7 Modelling of indicative prices suggests that approximately 56%, or $449m of revenue in 21/22 would relate to the residual charge.

122 Gross energy includes all consumption behind a customer's point of connection (not just grid offtake).

123 In order to calculate residual charges on a gross basis, Transpower would need information about/to estimate activity behind the customer's point of connection. The Authority is considering the need for a supporting Code amendment to facilitate the collection of such information – see paragraph 2.18. However, if the Authority did proceed with such an amendment, it is possible that some of this information may not be available to Transpower initially. See *Reasons* paper, 30 June 2021, Chapter 16, Sections 3 and 4. For this reason, the Authority is considering, as an alternative option, including transitional provisions in the proposed TPM to provide for residual charges to be set on an interim basis initially, with a wash-up to reallocate residual charges once more accurate data on embedded electricity becomes available.

7.8 This section addresses several matters relating to the residual charge which have arisen out of the development of the proposed TPM. There is also a significant policy issue relating to the application of residual charges to battery storage, which is also covered below.

Generation with embedded load

7.9 As required by the Guidelines,[124] the proposed TPM applies the residual charge to grid-connected generators with embedded load, treating them as 'supplying load customers'.[125]

7.10 The reason for this provision is to avoid creating an incentive for load to connect (or remain connected) to the grid through a generator to avoid transmission charges, even when it is more efficient for it to connect in some other way. It also avoids such load getting a potential artificial competitive advantage.

7.11 As such, this proposed approach better meets the Authority's statutory objective than not doing so, by promoting both competition and efficient operation of the industry.

7.12 Transpower considers that this proposed treatment of grid-connected generators with embedded load is a departure from certain provisions of the Guidelines, for example because clause 27 of the Guidelines refers to 'load customers' and that the definition of 'load customer' does not capture generation with embedded load. However, it considers the departure is justified under clause 2 of the Guidelines.[126] The Authority considers that the application of the residual charge to generation with embedded load is consistent with the Guidelines. But even if it were not, the Authority agrees with Transpower the proposal would be justified under clause 2.

Embedded generation that injects into the grid

7.13 Transpower has given some further thought to a potential anomaly identified by the Authority in its feedback on Transpower's 30 June 2021 proposed TPM relating to the situation where an embedded generator injects into a distribution network (or other load customer) and the injection passes through into the grid. In this situation, it does not appear appropriate for the grid injection to be counted as part of gross load (which is used to allocate the residual charge).[127]

7.14 For these reasons, Transpower proposed in its 15 September refer-back part 2 response that a provision be included in the proposed TPM allowing grid injection to be netted off in these circumstances.[128] This is a proposed departure from the residual charge provisions of the Guidelines, using clause 2.

7.15 The Authority considers Transpower's proposed amendment to its initial TPM proposal is consistent with the intent of the Guidelines and better promotes the Authority's statutory objective (compared to the TPM that it proposed on 30 June

124 Clauses 27 and 7. See also discussion beginning on page 8.7 of Transpower's *Reasons* paper (section 5 "Grid-connected generators with embedded load").

125 Note that there are no current examples of such customers. The proposed TPM also distinguishes a category of intermingled generation/load customers (such as Whareroa Cogeneration). See paragraph 12.35. Such customers are also allocated a residual charge.

126 See paras 28, 36-38 of Chapter 8 of the *Reasons* paper

127 The issue arises because otherwise gross load is calculated as offtake plus embedded electricity, which would capture electricity produced by embedded generation.

128 See Transpower, 15 September refer-back part 2 response submission, section 5.2, paras 54-58. This change is described and illustrated in Clause 5 of the resubmitted proposed TPM.

which did not address this issue). The residual charge is intended to be allocated based on customer size (as a proxy for ability to pay). The residual allocator is intended to capture a load customer's final electricity demand. That means it should capture electricity sourced from embedded generation that is consumed by the load customer – not electricity that is reinjected into the grid at that load customer's GXP. We also agree with the reasoning in Transpower's resubmission.[129]

Residual charge for new load customers

7.16 The setting of residual charges for new load customers is discussed in chapter 0.

Application of residual charge to battery storage

7.17 The proposed TPM allocates the residual charge based on final consumption. For battery storage, this means the residual charge is allocated based only on the battery's losses (energy in minus energy out), not its total energy used when charging. In this section we explain the reasons behind this approach.

7.18 When the residual charge components of the Guidelines were set, there had not been significant discussion, or stakeholder input, on the application of the residual charge to storage, and particularly to grid-connected batteries. The Guidelines therefore effectively treated batteries and other storage as load when charging, which means that the residual charge would be payable in relation to their total energy used when charging.

7.19 The issue of competitive neutrality for batteries with other generation, particularly in relation to the residual charge was raised by Contact in November 2020. Since then, Transpower and the Authority have been considering this issue, and Transpower released an issues paper on this matter in March 2021.

7.20 Transpower's 25 August resubmitted TPM proposal is consistent with clauses 27 to 30 of the Guidelines in that it treats all grid-connected and embedded batteries as gross load for their entire energy used when charging and any charging from embedded electricity. Consistent with the view expressed in its Checkpoint 2c submission, Transpower's 25 August Reasons paper explained 'the battery issue is a policy matter which is most appropriately resolved by the Authority'.[130] The Authority accepted this position.[131] The Authority has therefore led policy development on this matter and has engaged with Transpower on potential options that may best promote the Authority's statutory objective. The proposed TPM differs from the TPM proposed by Transpower with respect to this matter.

7.21 The Authority welcomes stakeholder feedback on our problem definition (the double counting described below), our proposed approach (allocating the residual charge based on final consumption), the alternatives identified, and our proposed method to implement our policy intent (a partial exemption for battery storage from the residual charge).

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129 See Transpower, 15 September refer-back part 2 response submission, section 5.2, para 57.

130 Transpower 25 August 2021

131 Electricity Authority, response to Transpower's Checkpoint 2c submission, 25 May 2021

Proposed allocation of residual charge based on final consumption

7.22 The proposed TPM allocates the residual charge to each load customer based on its final consumption of electricity. This means battery storage is charged based on total energy finally consumed by the battery storage (that is, the difference between energy in and out) and if relevant, by other connected load,[132] rather than allocating the residual charge based on the battery storage system's total energy used when charging (ie, its offtake from the grid or from embedded generation).[133]

7.23 This effectively means that energy that is stored is only counted once, rather than being counted both when it is stored in the battery and when it is finally used. Any losses during battery storage are also counted towards its residual charge. The proposed approach places batteries on a level playing field with other generation, embedded generation and cogeneration (as energy supplied from these sources is also counted once).

7.24 While the more detailed provisions of the Guidelines do not explicitly provide for such an approach to storage, clause 2 of the Guidelines allows the proposed TPM to differ from the details of the Guidelines in order to better promote the Authority's statutory objective. The Authority welcomes feedback on our initial view that the proposed approach would better promote its statutory objective and is therefore consistent with clause 2.

For battery storage there is a risk of 'double-counting' load

7.25 As discussed in the section above, the residual charge seeks to recover remaining allowable revenues (or costs) in the least distortionary manner. This is in contrast to the benefit-based charge which looks to encourage efficient incentives.

7.26 Because of the nature of the costs it recovers, the residual charge is not linked to benefits received by customers or costs created by customers. Rather, in designing the approach to the allocation of the residual charge the Authority's key concern was to ensure that the residual charge recovers remaining revenues in a way that minimises distortions to behaviour which might otherwise undermine signals sent by (for example) the benefit-based charge.

7.27 The particular challenge with battery storage is that there is a risk of 'double-counting' load (for the purposes of residual charge allocation), which the Authority wants to avoid.[134] This would happen if (where a customer owns a battery) the customer's load is counted once when the battery is charged, and counted again when the battery is discharged and that energy is used by final consumers. The issue is particularly noticeable where one customer has both a battery and embedded load consuming electricity from the battery, since the customer would incur charges both when the battery was charging and when it was discharging/that electricity was used by the

132 For a standalone grid-connected battery, final consumption would be that battery's losses. For a load customer with a connected battery, (eg, a factory), final consumption would be that factory's load plus the battery's losses.

133 Final consumption of electricity can be measured in various ways. The proposed TPM measures it by adding grid offtake to 'embedded electricity', where battery injection is excluded from the measurement of embedded electricity. This results in the same total quantum for the residual allocator as a direct measurement of 'load + battery losses' but is a more practicable way to achieve the same thing.

134 That is, if a transmission customer, (eg, a distribution network) installs a battery that customer will face an increase in residual charges even if the customer's load does not change.

final consumer. However, it would also be an issue where a grid-connected battery incurred charges while charging, that energy was re-injected into the grid and the final customer elsewhere on the grid incurred charges for final consumption. This double counting would create an extra cost for storage not faced by other generators,[135] and so would result in a competitive disadvantage.[136] The additional cost is in the order of a 3.75% increase on investment cost for battery storage, compared to an equivalent generator.[137]

7.28 Battery storage can provide a range of valuable services. These include smoothing supply, and therefore prices, at times where environmental and market conditions may mean supply constraints would otherwise result in rising prices, providing reserve energy, voltage support and frequency keeping. Smoothing supply will support a lower cost transition pathway to low emissions. The Authority's intent is to ensure that, in providing such services, battery storage is on a level playing field with others – recognising other participants will also provide useful services.

7.29 If not addressed, the double counting risk could inefficiently discourage investment in battery storage, and so distort generation investment decisions (such as by substantially increasing the costs of intermittent renewables combined with energy storage). That would risk the proposed TPM not adequately conforming with the statutory objective (including because it would not promote efficient operation of the industry or competition between batteries and other forms of generation). The Authority welcomes stakeholder feedback on the double counting problem identified, and on this estimate of the investment cost impact of this problem.

7.30 Worked examples of how double counting could arise if the residual charge is allocated based on a battery's total energy used when charging are presented at Figure 3. We have considered how gross energy could be calculated for the following situations:

(a) A battery storage system behind a point of connection, with no embedded generation and no load directly served by that battery.

(b) Embedded generation and load behind a point of connection, with no battery storage.

(c) Embedded generation and load behind a point of connection, with a battery storage system.

7.31 The equations demonstrate how gross energy would be calculated under the detailed residual charge provisions of the Guidelines and without the use of clause 2 for battery storage. The MWh quantities shown are clearly not accurate and intended only to illustrate the different approaches.

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135 Note the Authority's 2020 decision to change the Code's definition of a generating unit https://www.ea.govt.nz/assets/dms-assets/26/26430Broadening-definitions-of-Generating-Unit-and-intermittent-Generating-Station-Decision-Paper.pdf

136 See: Authority letter to Transpower (7 December 2020) *Transpower's TPM Checkpoint 2a submission* and Authority letter to Transpower (18 March 2021) *Proposed TPM residual charges and the treatment of batteries*. During the checkpoint process the Authority accepted Transpower's view that this is a policy matter most appropriately considered by the Authority.

137 This is more than de minimis. Sense Partners' analysis relates to investment costs for a single simplified battery project with investment costs of $1m per MW; compared with an equivalent grid-connected cogeneration plant or diesel generator, or network-level embedded hydro generator. Sense Partners, 2021: *Batteries and residual transmission charges – options for ensuring efficient cost recovery*.

7.32 These worked examples demonstrate that if the Authority did not act under clause 2 to address the problem, battery storage would be charged on the basis of its full energy used for charging, despite returning most energy to the grid or to a load customer – and that a system which takes in roughly the same amount of electricity would incur significantly greater residual charges (compared to a system without a battery) simply because the energy was being stored in a battery for a time.

7.33 Consistent with the Authority's statutory objective, we consider that the residual charge should apply to battery storage in a way that is efficient and least distortionary, such that it:

(a) is competitively neutral across all types of generation, including storage

(b) ensures all load attracts the residual charge on the same basis, regardless of where/what/who is supplying its electricity (and thus minimises distortions and promotes efficient operation of the industry)

(c) creates scale neutrality (no biases towards or against larger scale storage)

(d) is future proof as new storage technologies develop, given the market for storage is immature and storage technology is rapidly developing.

7.34 We note for clarity that storage would be charged benefit-based charges under the proposed TPM in the ordinary way.

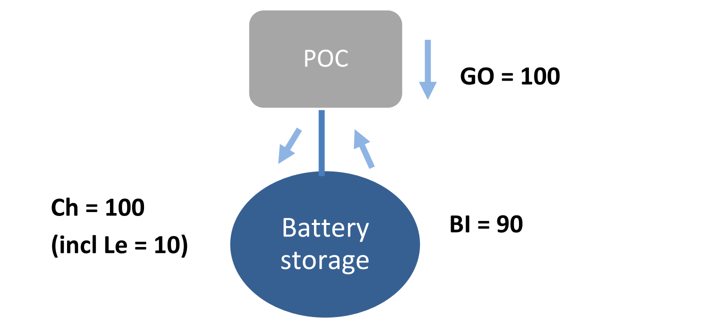
Figure 3 Application of the residual charge to a customer under TPM proposed by Transpower 30 June 2021 (based on total energy used to charge battery storage)

KEY:	POC GO EGI Load	= point of connection = grid offtake *(varies to balance system)* = embedded generation injection *(fixed at 50MWh)* = Final consumption/load – *(fixed at 150MWh)*	Ch BI Le	= battery storage charging *(fixed at 100MWh)* = battery storage discharging/injection = losses (energy consumed by battery storage)

Notes: 1) Quantities over a measurement year. 2) Circuit diagrams are simplified to show gross energy calculations. 3) Residual charge allocated based on gross energy, indicated in red

ALLOCATING THE RESIDUAL CHARGE TO BATTERY STORAGE BASED ON TOTAL ENERGY USED TO CHARGE BATTERY STORAGE:

Customer runs a battery only (there is no load beyond the point of connection)

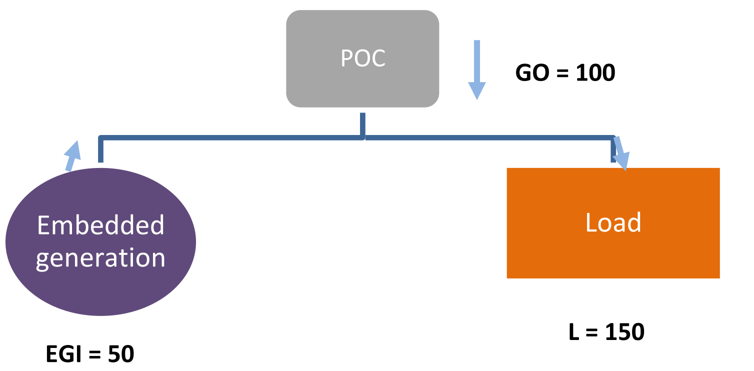


Gross energy = GO = Ch

= 100 = 100

Gross energy > Le

Load customer runs embedded generation and no battery



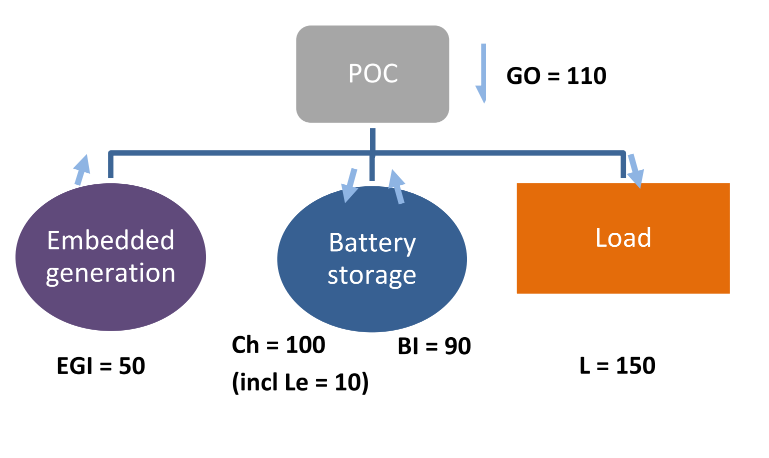
Gross energy = GO + EGI

= 100 + 50 = 150

Gross energy = Load

Load customer runs embedded generation and a battery

KEY:				
	POC	= point of connection	Ch	= battery storage charging *(fixed at 100MWh)*
	GO	= grid offtake *(varies to balance system)*	BI	= battery storage discharging/injection
	EGI	= embedded generation injection *(fixed at 50MWh)*	Le	= losses (energy consumed by battery storage)
	Load	= Final consumption/load – *(fixed at 150MWh)*		



Gross energy = GO + EGI + BI

= 110 + 50 + 90 = 250

Gross energy > Load

Defining battery storage

7.35 We propose to use the term 'battery storage' to refer to all systems where electricity is the key input and output and which can be said to store that energy (albeit in a form other than electricity). Such systems use electricity from the grid or a local network and convert that electricity to energy, then store that energy, then later convert the energy back to electricity to inject onto the grid or directly to a load customer or onto a local network.

7.36 We propose the term 'battery storage' instead of the term 'battery' that was proposed by Transpower. However, the wording in the definition otherwise aligns exactly with that proposed by Transpower. It is a deliberately broad definition and includes a range of methods and equipment for storing electricity, including:[138]

(a) Electro-chemical storage, eg, lithium-ion and redox flow batteries.

(b) Electrical storage, eg, capacitors.

(c) Mechanical storage, eg, compressed air energy storage, flywheels and *pumped* hydro storage systems.

(d) Chemical storage, eg, hydrogen.

7.37 The term 'battery storage' does not, and is not intended to, cover long term fuel storage such as a (non-pumped) hydro generation lake or system of lakes and dams, since such systems do not take electricity off a network and convert it into another form at the outset. The 'battery storage' term also does not, and is not intended to,

138 Pumped hydro storage has the greatest capacity of these technologies globally (over 95% of capacity) while electro-chemical batteries are by far the fastest growing form of battery storage.

cover tail water depressed (TWD) reserve and partially loaded spinning reserve (PSLR) (hydro or gas), for similar reasons.[139]

7.38 The Authority welcomes stakeholder feedback on

whether our proposed definition of 'battery storage' is appropriate to capture what is intended to be covered, and not covered, as described above.

7.39 The Authority recently decided to amend the Code to enable some energy storage system (ESS) owners to offer injectable instantaneous reserve.[140] The Authority's proposed TPM does not use the same ESS term, because we intend to clearly distinguish the TPM's definition from ESS. The Authority agrees with Transpower that the term ESS could be too narrow for the purposes of the proposed TPM,[141] because:

(a) a battery or battery storage system may be charged directly from generating plant and not 'from a network' (as required under the ESS definition); and

(b) 'injection' (as used in the ESS definition) means injection into a network, whereas a battery may inject directly into consuming plant and this would need to be captured for TPM purposes.

Policy options considered by Transpower and the Authority

7.40 The Authority has considered three main approaches to address the double counting issue. These are to allocate the residual charge to battery storage based on:

(a) **total energy used when charging** (which is the same as final consumption plus injection by battery storage). This means battery storage is treated as a load customer for its entire offtake and embedded electricity consumption (as shown in Figure 3). That is, electricity is counted both when charging the battery and when finally used.

(b) **final consumption** (any load, plus battery storage losses). This means battery storage is exempted from the residual charge with respect to offtake and consumption of embedded electricity while charging, except as to losses during transformation. That is, only electricity which is finally used and cannot be reinjected is counted.

(c) **final consumption minus battery storage losses**. This means battery storage is fully exempted from the residual charge with respect to offtake and embedded electricity consumption while charging.

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139 TWD and PLSR refer to two different mechanisms for generators to provide reserves. TWD (tail water depressed) is a method that allows hydro generators to provide reserves when not providing power. The turbine is filled with air and is synchronised with the grid but not providing power. If the grid frequency drops to the required trigger point, water is rapidly allowed to enter the turbine and the turbine starts generating power to satisfy its reserve dispatch. PLSR (partially loaded spinning reserve) is capacity on a synchronised and generating generator (of any type) that has been dispatched to provide reserves. On grid frequency falling to the reserves set point, the generator will automatically ramp up rapidly to provide the power it is required to in its reserve dispatch.

140 Electricity Authority, July 2021, Announcement and decision paper at https://www.ea.govt.nz/development/work-programme/evolving-tech-business/batteries-as-instantaneous-reserve/development/decision-paper-published/

141 Discussion between Transpower and Authority staff.

7.41 In its March 2021 consultation[142] Transpower sought stakeholder views on these same three main alternative options. To clarify for stakeholders:

(a) The Authority's first approach (total energy used when charging the battery storage) is Transpower's **no change** option.

(b) The Authority's second approach (final consumption) is Transpower's **partial exemption** option.

(c) The Authority's third approach (final consumption minus battery storage losses) is Transpower's **full exemption** option.

7.42 In considering approaches to address the double counting issue, we have taken account of Transpower's analysis reported in its March 2021 issues paper on this matter, the divergent views in stakeholder submissions to that paper, Transpower's checkpoint material, its June 2021 Reasons paper and its 25 August response to the Authority's refer-back decision.

7.43 We have also taken account of approaches in place or under development overseas to the application of residual charges to battery storage systems – as summarised in the box below. The Authority welcomes stakeholder feedback on the above approaches and whether there are any additional options we should be considering.

[142] Transpower, *Residual Charges and the Treatment of Batteries Options Consultation March 2021*, Part 7

International approaches to charging storage for transmission

Australia

Australia is considering rules to exempt storage from transmission charges. Australian regulators are currently reviewing market rules with a view to introducing a new class of industry participant for energy storage assets.

The Australian Energy Market Operator (AEMO, 2019) proposed introducing a 'Bi-directional Resource Provider' participant category and that Transmission use of system (TUOS) charges should not be charged for bi-directional assets, but that distribution use of system (DUOS) charges should be levied on the load component of bi-directional assets. The Australian Energy Market Commission (AEMC) has been consulting on this and other rule changes for integrating energy storage systems into the electricity market. In a draft determination on 15 July 2021 the Commission has proposed that storage should not be exempt from both TUOS and DUOS because a blanket exemption would undermine technological neutrality. The Commission noted that the issue should be how much customers should pay, including storage, not whether or not they should pay anything at all.

European Union

Treatment of storage varies widely across the European Union. DG Energy (March 2020) reviewed the treatment of energy storage in member states' electricity markets, including with respect to transmission charges. Several member states are in the process of implementing changes to transmission pricing to avoid problems of double-charging transmission for storage, (ie, where it is treated as generator and load).

Transmission pricing practices vary considerably in the EU. Several member states charge generators and load for transmission interconnection costs. This has the effect that storage, including pumped hydro, faces both demand charges and generation charges in some member states. Other member states recover transmission interconnection costs solely from load, though this leads to charges being levied twice on energy that is stored and then consumed and creates an uneven playing field with respect to other providers of services such as reserves and voltage support.

United Kingdom

The United Kingdom has decided not to levy residual charges on storage. In November 2019 Ofgem confirmed: 'We will be removing liability for the transmission generation residual from generators' and 'residual charges will be levied in the form of fixed charges for all households and businesses.' Reasons included that storage facilities faced 'a disproportionate charging regime'. This decision means that from next year generators will no longer face residual charges (or receive payments for embedded generation).

In October 2020 Ofgem further decided that, in line with earlier decisions, "residual charges should be paid by final demand only, thereby excluding all types of generation (including stand-alone storage) from residual network charges.

United States

In general, the US exempts storage from charges where it provides market services. In the United States, rules that distinguish storage assets from generation or load are well-developed compared to other jurisdictions but only in the case of storage assets being used for ancillary or network support services. The treatment of storage in other instances is less clear.

FERC has ruled that energy storage must not be charged use-of-system charges if it is providing scheduled network support services (including frequency keeping, reliability/reserves and voltage support). This is intended to ensure even-handed treatment of energy storage in the market for network support services. For other services provided by energy storage, including load shifting, FERC has said that it will make decisions about the treatment of these services or assets on a case-by-case basis depending on the both the specific services being provided by energy storage assets and the context in which they are provided including prevailing transmission tariffs. Thus the treatment of storage assets remains a matter for the judgement of regional transmission and independent system operation organisations.

The Californian system operator (CAISO) does not levy residual transmission charges on energy storage, which it views as consistent with its practice of not levying residual charges on generators.

PJM treats large Pumped Hydro Storage Units as generators and does not assess transmission charges to them.

NYISO proposed to treat the charging of storage as negative generation that does not attract any transmission service charges, to the extent that withdrawal is for later injection to the grid. However, this approach was rejected by FERC - on the grounds that it treated storage differently to other load.

7.44 Worked examples of how gross energy could be calculated under the second approach (based on final consumption) or the third approach (based on final consumption minus battery storage losses) are presented at Figure 4.

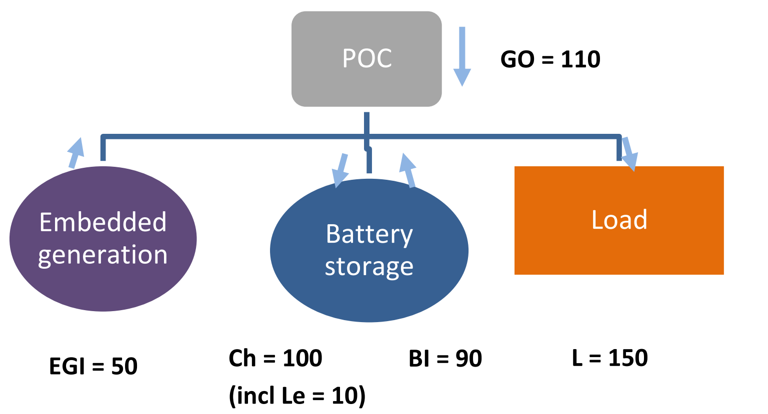
Figure 4 Application of residual charge under proposed TPM: allocated to a customer based on final consumption vs full exemption

KEY:	POC	= point of connection	Ch	= battery storage charging *(fixed at 100MWh)*
	GO	= grid offtake *(varies to balance system)*	BI	= battery storage discharging/injection
	EGI	= embedded generation injection *(fixed at 50MWh)*	Le	= losses (energy consumed by battery storage)
	Load	= Final consumption/load – *(fixed at 150MWh)*		

Notes: 1) Quantities over a measurement year. 2) Circuit diagrams are simplified to show gross energy calculations. 3) Residual charge allocated based on gross energy, indicated in red

ALLOCATING THE RESIDUAL CHARGE TO BATTERY STORAGE BASED ON FINAL CONSUMPTION:

Load customer runs embedded generation and a battery



Gross energy =

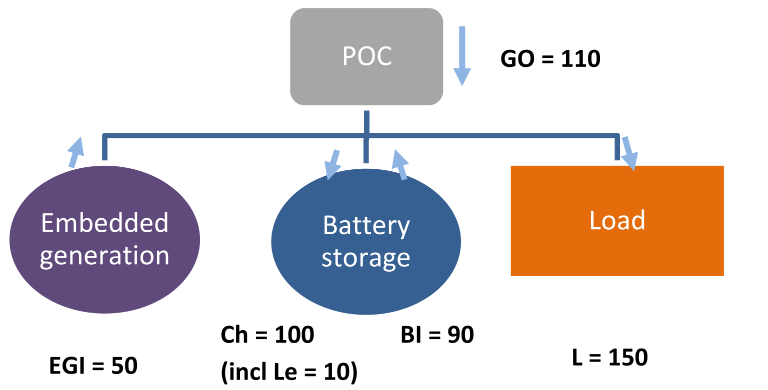
GO + EGI

110 + 50 = 160

Gross energy = Load + Le

ALLOCATING THE RESIDUAL CHARGE TO BATTERY STORAGE BASED ON FINAL CONSUMPTION MINUS BATTERY STORAGE LOSSES:

Load customer runs embedded generation and a battery



Gross energy =

GO + (EGI + BI) - Ch

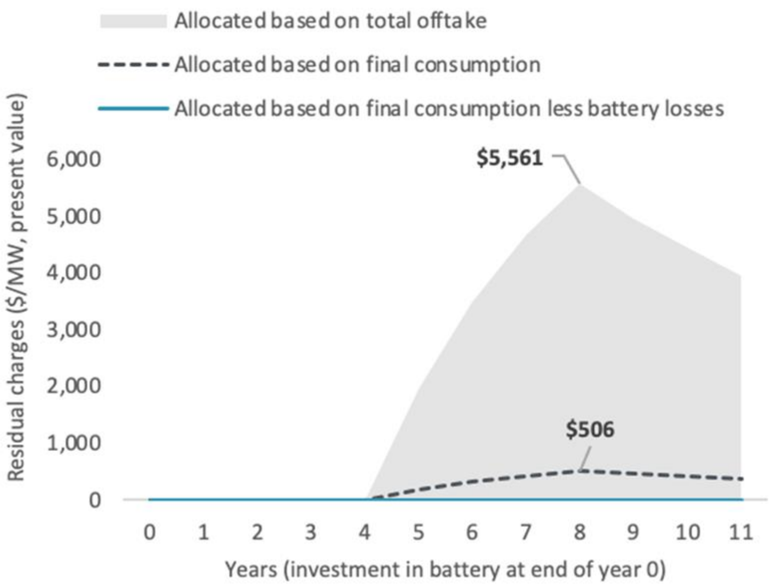
110 + (50 +90) - 100 = 150

Gross energy = Load

Assessment of the effect of the options on residual charges

7.45 To illustrate the nature of the effect on residual charges of the three main options considered (see paragraph 7.40 above), Figure 5 shows the resulting residual charge allocation, over an eleven-year period. The example shown is for a hypothetical simplified single 10MW battery storage investment by an existing designated transmission customer, from its becoming operational. Investment costs are assumed to be $1m per MW.

Figure 5 Worked example of options for application of residual charge



7.46 Under this example, the allocation of the residual charge to a battery storage customer, in year 4, is ten times higher if allocating based on the first option (total energy used for charging the battery storage – 'total offtake'), compared to when allocating based on the second option (final consumption). (This reflects the fact that a battery's losses are a small proportion of its total storage capacity.) Under the third option, no residual charge is allocated.

7.47 The 'shape' of the residual charge over time, under the first and second options, would be determined by the proposed approach to the residual charge in general, and is not specific to battery storage. The initial allocation for a load customer would be based on historical AMD. As the residual charge effectively lags application to new investments, there would be no allocation for years 0-3, the allocation would start from year 4 and be fully allocated by year 8.

7.48 More generally we expect residual charges to decline over time as historical assets within the residual depreciate (meaning the total residual to be allocated declines). This ramp up and down for the total energy used for charging option is shown by the 'shark fin' shape in Figure 5. The shape is muted for the final consumption option. We note also for clarity that in Chapter 0 we explain our proposal that the shape for the residual charge allocation over time be the same for a new customer as for an existing expanding customer.

The Authority proposes to allocate the residual charge to battery storage based on final consumption

7.49 Having considered the options previously identified by Transpower, the Authority considers that allocating the residual charge to battery storage based on final consumption would better promote our statutory objective and has amended the proposed TPM accordingly. The Authority welcomes feedback on this amendment to the proposed TPM, and the alternatives described.

7.50 Sense Partners estimate this proposed approach would result in a battery storage unit facing a 0.25% higher investment cost than an equivalent generator. This is substantially less than the 3.75% difference in investment cost that arises under the first option (no consideration of battery storage) (see paragraph 7.27).

7.51 The proposed TPM therefore allocates the residual charge to battery storage based on final energy consumed (as losses) by the battery storage (and if relevant, by other connected load), rather than allocating the residual charge based on the battery storage system's total energy used when charging.

7.52 In this chapter we largely consider the application of the residual charge in respect of battery storage installed by existing transmission customers. However, the Authority has also considered how this approach should apply when setting an initial residual charge for a new customer:

(a) For a new grid-connected battery, we consider that a residual charge based on AMD calculated according to final consumption (the battery's losses) would be appropriate, for the reasons discussed above.

(b) However, we consider a different approach is likely required in the case of a battery storage system that is embedded behind a new entrant load customer. Such a battery is unlikely to charge during times of peak demand (AMD) for the relevant grid-connected customer, so the presence of battery storage is unlikely to increase that load customer's AMD. So our proposal is that in this situation the battery's losses would not contribute to the load customer's AMD for the purposes of setting the customer's initial residual charge.

(c) Thus, when Transpower estimates the AMDR of a load customer with an embedded battery, the proposed TPM provides for it not to add any contribution from the charging or discharging of any (large)[143] battery.[144]

(d) By contrast, when Transpower estimates the AMDR of a new grid-connected battery, the proposed TPM provides for it to estimate the AMDR according to the battery's losses.

(e) An alternative approach would be not to make this exception in the case of battery storage embedded behind a new entrant load customer (such that the embedded battery's losses would contribute to the load customer's AMD).

(f) We invite stakeholder views on this matter.

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143 Due to challenges obtaining data on small batteries, this approach is proposed to be applied only to batteries sized above 10MW. However, the Authority is open to considering evidence supporting an alternative threshold, or no threshold – if it is considered unnecessary to distinguish based on size.

144 After the initial residual allocator is set, the load customer's residual charge would update based on final consumption as set out in this chapter. The different approach applies only to the initial residual charge.

7.53 While the more detailed provisions of the Guidelines do not explicitly provide for the preferred ‘final consumption’ approach, clause 2 of the Guidelines allows the proposed TPM to differ from the details of the Guidelines in order to better promote the Authority’s statutory objective. The Authority welcomes feedback on our initial view that a departure from the Guidelines, enabling the residual to be allocated based on final consumption is justified under clause 2 as this approach better aligns with the Authority’s statutory objective.

7.54 The Authority proposes to allocate the residual charge based on final consumption because this approach:

(a) reduces any competitive disadvantage storage faces compared to other generation, and does not create any incentives for parties to alter connection and supply arrangements just to avoid paying the residual charge. Under the Authority’s proposal, unless a party is disconnected from the grid, the residual charge cannot be avoided.

(b) addresses the double counting issue appropriately. The approach charges batteries for what they actually consume. From a policy point of view the Authority does not consider that allocating the residual charge based on energy used when charging, and so vastly increasing the assessed size/ability to pay of the customer, is rational or efficient. In addition, having considered stakeholder submissions to Transpower on this matter, the Authority sees no reason to consider that the ‘final consumption’ approach would advantage battery storage over generation it will compete with.

(c) does not create new scale-neutrality challenges. To apply the preferred approach, Transpower does not need to know the location and size of every battery, rather, Transpower simply needs to be able to see the electricity that flows in, and out, of a customer’s connection. The net annual electricity consumed (gross energy) by that customer will include any battery losses.

(d) would create a smaller measurement burden, and will necessitate far lower transaction costs to operationalise, than a full exemption. The preferred approach can be implemented without any specific steps to gather new information or new measurement of flows (see further discussion around information Transpower might require more generally at the end of this section). Under the preferred approach, behind-the-meter storage would be treated on the same basis as utility scale storage directly connected to distribution networks or the grid.[145]

7.55 Transpower’s 25 August response to the Authority’s refer-back letter confirmed it also considers that allocating the residual based on final consumption (which Transpower referred to as the ‘partial exemption’ option) would pose the fewest workability challenges. The Authority welcomes stakeholder feedback on its proposed approach.

7.56 During Transpower’s March 2021 consultation, some parties (including IEGA) communicated a view that treating battery storage differently to other load would

145 This is because, if energy injected by storage is not measured in concurrent generation, then when calculating residual charges, that storage will be subject to the partial exemption by default. It is only if battery energy storage is counted in concurrent generation that an additional step would be required to implement the partial exemption.

create an unfair advantage to battery storage compared to other technologies. Others (including Contact) submitted that not treating battery storage differently would create an unfair disadvantage to battery storage.

7.57 Transpower summarised submissions on competitive neutrality, barriers to entry and the overall positions of submitters as:[146]

> ***Questions about competitive neutrality and barriers to investment:*** *It was contested whether the Guidelines treatment of battery storage as load and charged on the basis of AMD creates competitive neutrality issues or is a barrier to investment, ie, the submissions from IEGA, MEUG, Trustpower/Creative Energy Consulting and Vector. Meridian submitted it would not be a barrier to its battery storage plans. Opponents also raised broader competitive neutrality concerns, questioning why batteries should be exempt when other technologies provide similar services. IEGA, for example, submitted: 'If gross AMD is the wrong allocator for storage devices it is equally the wrong allocator for other types of participants that offer the same services, notably industrial load (especially with cogeneration) and distributed generation'.*
>
> ***Batteries are needed but no TPM exemption consensus:*** *The proposal to exempt/partially exempt grid connected batteries from the residual was contentious despite broad agreement about the importance of the technology for New Zealand's electricity future.*
>
> *There was a broadly even split between treating grid-connected batteries as load customers for their entire offtake and embedded electricity under the new TPM residual charge (option 1), applying clause 2 of the Guidelines to partially exempt (option 2) or fully exempt (option 3) battery storage from the residual. Other options were raised for our consideration as well, some of which were outside the scope of TPM development.*

7.58 The Authority is also mindful of concerns raised by Nova concerning treatment of embedded generation compared to batteries. The Authority does not intend this part of the proposed TPM to create any preferential treatment for either battery storage or embedded generation: our intent is to create a more level playing field for all parties injecting onto the grid.

7.59 Figure 6 below compares the proposed approach to the residual charge for an embedded generator and a battery storage unit. To enable a like-for-like comparison, the panels below assume equal injection from the embedded generator and the battery. This worked example shows that under the proposed TPM (including the Authority's proposed approach for battery storage):

(a) the residual charge for the load customer relying on embedded generation is based on a measure of gross load that is exactly equal to the load customer's energy consumption over the two periods (150 in this example)

(b) the residual charge for the load customer relying on battery storage is based on a measure of gross load that is equal to the final energy consumption of the system (load and battery) as a whole: that is, the load customer's energy

146 Transpower, TPM Development: Residual charges and the treatment of battery options consultation. Summary and response, May 2021, page 7.

consumption plus the battery's final energy consumption (ie, losses) over the two periods (160 = 150 + 10 in this example).

7.60 This demonstrates that under the proposed TPM embedded generation is not placed at a disadvantage compared to battery storage; rather, both technologies are on a level playing field as customers with either technology are both charged according to their final energy consumption.

7.61 By contrast, the worked example shows that under the alternative option (the residual allocated based on total energy used in charging the battery, as per the TPM proposed by Transpower on 30 June), battery storage is at a significant competitive disadvantage compared to embedded generation. That is, gross load (and hence the residual charge) for the load customer relying on battery storage over the two periods (210) is significantly higher than gross load (and residual charge) for the load customer relying on embedded generation (150), despite them using approximately the same amount of electricity. This occurs because 50MWh of energy is double-counted for residual charge purposes: it is counted once in period 1 (as grid offtake) and then double-counted in period 2 (as battery injection) – even though the energy is only consumed once (by the load customer in period 2). The proposed TPM corrects this anomalous result through the proposed 'final consumption' approach.

Figure 6 Application of the residual charge to embedded generation and a battery storage unit - Calculation of gross energy

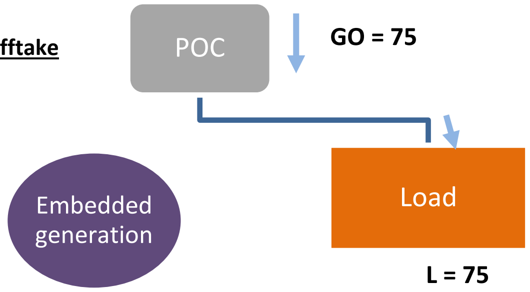
KEY:				
	POC	= point of connection	Ch	= battery storage charging *(60Wh – for this comparison)*
	GO	= grid offtake *(varies to balance system)*	BI	= battery storage discharging/injection
	EGI	= embedded generation injection *(fixed at 50MWh)*	Le	= losses (energy consumed by battery storage)
	Load	= Final consumption/load – *(fixed at 150MWh)*		*Residual charge allocated based on gross energy, indicated in red*

Notes: 1) Quantities over a measurement year.
2) Circuit diagrams are simplified to show gross energy calculations.

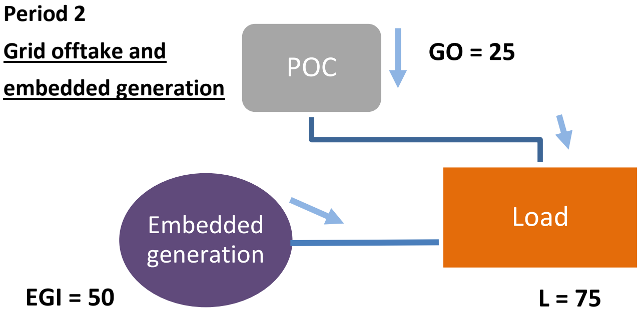
APPLICATION OF THE RESIDUAL CHARGE TO EMBEDDED GENERATION:

Load customer runs embedded generation

Period 1
Only grid offtake



Period 2
Grid offtake and embedded generation



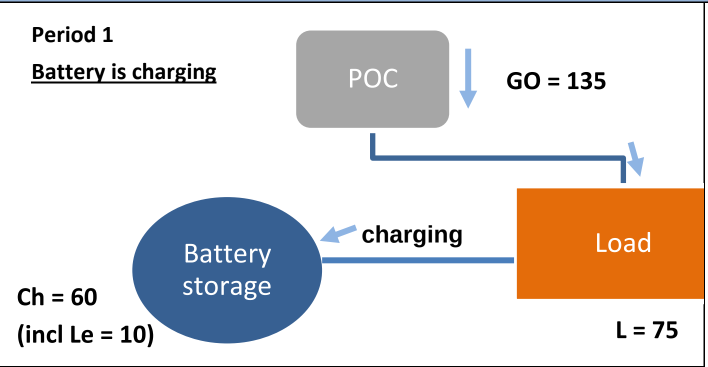
P1: GO only:		**= 75**
P2: GO and EG:	**= 25 + 50**	**= 75**
Across 2 periods:		**Total = 150**

Gross energy = Load

APPLICATION OF THE RESIDUAL CHARGE – UNDER TPM PROPOSED BY TRANSPOWER 30 JUNE 2021 (ALLOCATED ON TOTAL ENERGY USED TO CHARGE BATTERY) VS UNDER PROPOSED TPM (ALLOCATED ON FINAL CONSUMPTION FOR A BATTERY)

Load customer runs a battery (splitting the measurement period 50/50 into charging and discharging)

Residual charge allocated based on gross energy, indicated in red



Gross energy =

TPM proposed by Transpower 30 June 2021 (allocated on total energy to charge battery):

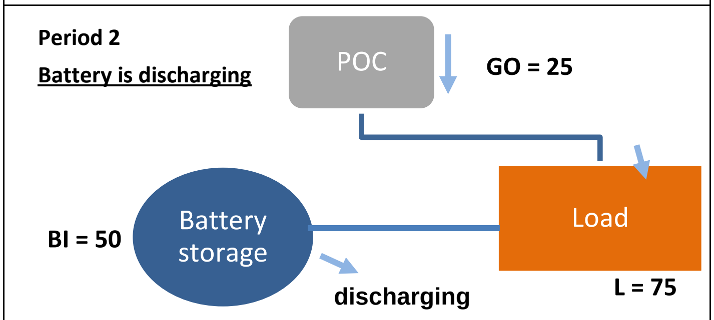
P1, charging: = GO = 135

P2, discharging: = GO + BI = 25 + 50 = 75

Total = 210

Gross energy > Load

Gross energy > Load + Le



Proposed TPM (allocated on final consumption):

P1, charging: = GO = 135

P2, discharging: = GO = 25

Total = 160

Gross energy = Load + Le

7.62 To reiterate, the Authority's intention is not to provide energy storage with a competitive advantage; rather, we are aiming to remove an unintended structural disadvantage to storage that arises under the proposed TPM. The Authority's intention is to propose a technology-neutral solution. We welcome submissions on this matter.

7.63 Storage is an evolving area and the approach we propose is a future-proofing approach – because it allocates the residual charge based on final consumption, and so can apply to a range of battery storage systems. The Authority considers this proposal for a modified allocation metric best aligns with technological neutrality across batteries and other generation. All consumers of electrical energy would be allocated a residual charge in a consistent manner. We welcome submissions on whether the proposed approach will be durable as technology evolves.

7.64 We recognise that there is a potential challenge in how the preferred approach should be implemented for battery storage types, such as pumped hydro, that can store energy across concurrent years (charge this year, then dispatch next year). The Authority proposes not to include a mechanism to cover this potential situation in the proposed TPM - if such a matter became an issue in the future, it could potentially be addressed via a Transpower operational review (or else, if the Code is ultimately amended to allow the TPM to be re-opened to address workability/implementation issues, under that provision). An alternative approach could be to consider and potentially include a mechanism to address this challenge now. The Authority welcomes feedback on whether such a mechanism should be included now and, if so, what it should look like.

The Authority does not propose the third option (residual charge allocated based on final consumption minus battery storage losses - or ‘full exemption’)

7.65 The Authority does not propose the third approach (residual charge allocated based on final consumption minus battery storage losses - Transpower’s ‘full exemption’) for the following reasons. The third approach:

(a) could be seen as going too far, potentially providing storage with a competitive advantage over other generation. All other customers face the residual charge to the extent they consume electricity, and a battery’s electricity consumption is the losses incurred in transformation (not the electricity reinjected into the grid or into consuming plant or a local network). In contrast a partial exemption for batteries puts them on the same footing as other customers (including generators who also use some load)

(b) would be substantially more challenging to implement than a partial exemption. Specifically, Transpower notes the potential challenge involved in identifying storage and accurately measuring energy flows related to storage for all embedded batteries, and more so for smaller, (eg, residential) batteries

(c) could in practice provide more favourable treatment to utility-scale systems over smaller distributed systems (such as those operated by flexibility traders), because, to give a battery a full exemption, Transpower would need to know that battery exists. This means batteries that are small enough for Transpower to be unaware of their existence would not benefit from a full exemption. The operation of small-scale battery systems is not easy to measure, and/or very costly to measure, and could be difficult to verify.

7.66 We recognise that the third approach could have a revelation incentive built into it, as battery owners or their agents would have an incentive to report their battery operation. However, this imposes higher transaction costs on consumers and participants compared with the partial exemption. The Authority therefore does not currently prefer this approach; however, welcomes feedback on it as a possible alternative.

Implementing this proposal via a partial exemption for battery storage

7.67 To implement this proposal for the residual charge to be allocated to battery storage based on final consumption the Authority has modified the following aspects of the revised TPM that Transpower proposed on 25 August:

(a) The term ‘battery’ (now ‘battery storage’).

(b) Clause 5(1), inserted a new 5(2) and amended clause 5(5) (now 5(6)), concerning load customers, gross energy and maximum gross demand.

7.68 The battery storage definition proposed is at clause 3 of the proposed TPM (general definitions) and is discussed above.

7.69 In terms of the substantive provisions of the proposed TPM, as set out above, the Authority’s aim is to exempt batteries from the residual charge when they are charging, such that they are only charged the residual charge in respect of their losses, ie, their final consumption.

7.70 However, in practice, Transpower will not necessarily have information about all batteries connected behind points of connection to the grid, such that it could separately calculate their losses as distinct from the rest of the electricity they offtake when charging. Following discussions with Transpower, the Authority proposes to enact the proposed approach by providing that batteries incur the residual charge when charging (whether from the grid or embedded electricity), but that any injection back into the grid should be netted off, while any embedded electricity provided to consumers or networks behind the grid by the battery discharging would not be counted for the purposes of the residual charge. This has the same outcome as exempting batteries when charging (such that they are only charged the residual charge in respect of their losses).[147]

7.71 Specifically, the Authority proposes amending clause 5(1), inserting a new 5(2) and amending what is now clause 5(6) to achieve this final consumption approach. This aligns with the approach proposed by Transpower in discussions with the Authority. Thus:

(a) Clause 5(1) would be amended to provide that it is subject to a new clause 5(2). This clause would also be amended to provide that the minimum embedded electricity allowed by this clause is zero. This is to avoid any risk of the presence of a battery (or indeed anything else) resulting in a negative figure for embedded electricity.

(b) New clause 5(2) would be added to provide that if the generating plant is a battery in the scenarios outlined, then the electricity provided by that battery will be deemed to be zero for the purposes of calculating embedded electricity.

(c) Clause 5(6) would provide that any electricity injected into the grid by a grid-connected battery is deducted from gross energy for the purpose of calculating total gross energy (which is used in the calculation of the residual charge).

7.72 The effect of the above is that where a battery is connected to the grid, its residual charge will amount to its offtake minus its injection – in practice, this means it will incur the residual charge in respect of its losses plus any embedded electricity supplied behind the grid. Where the battery is embedded, the connected customer will incur a residual charge in respect of any offtake from the grid or electricity provided by embedded generation to charge the battery; however, it will not incur a residual charge when the battery discharges that electricity again.

7.73 As noted above, the Authority is mindful of concerns raised by Nova concerning treatment of embedded generation compared to batteries. We consider this proposal does not create any preferential treatment for either battery storage or embedded generation. While the exemption takes effect when the battery is providing embedded electricity (or injecting into the grid), this is simply a practical workaround to avoid Transpower needing to precisely calculate batteries' losses or obtain complete information about all batteries behind a point of connection. In effect, it is the battery's charging which is being exempted from the residual charge (except for the battery's losses).

7.74 We note that the above approach seeks to reconcile potentially complex connection arrangements into one straightforward methodology for Transpower to apply. The Authority would be interested in any feedback from stakeholders as to whether our

[147] Although there will be a time value of money cost for long-term storage (such as pumped hydro).

proposed approach still works in more complex situations, involving various embedded generation, load and batteries connected behind a point of connection.

7.75 In terms of timing, the Authority is seeking to exempt a battery from the residual charge when charging (aside from its losses) but impose the residual charge when it discharges to supply embedded electricity. The Authority's amendments to the proposed TPM, however, achieve this outcome by imposing the residual charge when the battery charges but providing an exemption when it discharges. While this is intended to net off to the same amount, it would result in the residual charge being incurred at a slightly different point in time (during charging rather than discharging). However, the Authority considers that this timing discrepancy is unlikely to impact stakeholders' charges in practice because the residual charge updates based on average total gross energy use over a four-year period. This means any charging and discharging would likely net out.[148]

7.76 We are interested in hearing stakeholder views on both the design of our proposed approach (allocating the residual charge according to a battery storage system's losses so as to reflect final consumption), and the likely effectiveness of our proposed implementation mechanism to realise the policy intent.

Ensuring sufficient data is available for this approach to be feasible

7.77 Transpower has highlighted that there are non-trivial data availability challenges for all types of generation not injected into the grid (so not limited to battery storage) and suggests this needs to be addressed by a Code change outside the TPM.[149]

7.78 The Authority agrees that further Code amendments relating to information disclosure may be appropriate to help ensure that our proposed implementation approach is as practical as possible. The Authority agrees it is important that this matter is considered, as additional data would likely improve outcomes under the proposed TPM.

7.79 Further information on this is included at Chapter 2. Stakeholders can expect to receive communications, a full consultation and engagement on this matter, consistent with all Code change workstreams.

148 Apart from the time value of money difference noted above.

149 Transpower, TPM Proposal 30 June 2021 Decision Part 1 refer back: Transpower's response, para 61

Consultation questions

Do you have any comment on how the proposed TPM implements the residual charge provided for in the Guidelines?

Do you agree with the application of the residual charge to generation with embedded load, or can you suggest a better way to mitigate charge avoidance incentives and risk of an uneven playing field?

Do you have any comment on the proposed approach to application of the residual charge to battery storage to avoid double-counting of load?

8 Adjustments

8.1 In general, connection, benefit-based and residual charge allocations between designated transmission customers are intended to be relatively fixed, in the sense that transmission customers cannot take actions to inefficiently avoid their charges.

8.2 The Guidelines and the proposed TPM do provide for circumstances in which charges can be adjusted. The general approach proposed is summarised as follows:

(a) A transmission customer's allocators for benefit-based and residual charges are generally not intended to change.

(b) If a transmission customer exits (completely stops using grid-supplied electricity), Transpower will immediately cease to charge it benefit-based and residual charges.

(c) If a party becomes a transmission customer, it will immediately face annualised benefit-based charges that are the same as an otherwise identical incumbent. Its residual charge will 'ultimately' be the same as an otherwise identical incumbent.

(d) If a large customer substantially changes its use of the grid, its benefit-based charges adjust immediately, while its residual charges adjust gradually under the standard lagged residual charge adjustment – see (g).

(e) If a large party is indirectly connected to the grid through a transmission customer, the latter's charges adjust in the same manner that the large party's charges would have changed if it were connected directly to the grid.

(f) Following an adjustment, the allocators of all other relevant transmission customers adjust proportionately so that the allocators for each benefit-based and the residual charge sum to 100%.

(g) A customer's residual charge allocation updates gradually with a lag in line with its use of the grid (relative to that of others).

(h) If on rare occasions some circumstance or event causes a widespread substantial sustained change in grid use, benefit-based charges are reallocated.

(i) If an investment is substantially damaged or proves to be over-engineered, or if Transpower chooses to voluntarily under-recover its charges, its benefit-based charge can be adjusted accordingly.

Relevant sections in the Guidelines and proposed TPM

Guidelines	Proposed TPM
Clauses 11-12, 29, 31-44	Part F: Clauses 76-99 of the proposed TPM

8.3 Because adjustments to the benefit-based and residual charges for expanding and contracting customers parallel the treatment of entering and exiting customers, to ensure competitive neutrality, the discussion below focuses on the latter.

8.4 Similarly, because the treatment of these charges in respect of large embedded parties parallels the treatment of grid-connected parties, the discussion below focuses on grid-connected parties.

8.5 In both cases, the discussion about adjustments takes as given the parallel treatment of expanding/contracting parties and entering/exiting customers, and large embedded parties and grid-connected customers. Where the treatment of one of these parties is proposed to be different, this is discussed below.

Adjustments to a customer's connection charge

8.6 The proposed TPM provides for adjustments to the connection charge on the entry and exit of a customer and the partial sale of a business (clauses 77-81). The Guidelines do not explicitly provide for adjustments of the connection charge, but the proposal is consistent with the provisions for the benefit-based charge and current practice.

Adjustments to a customer's benefit-based charge

8.7 The adjustment provisions in Transpower's proposal for benefit-based charges are broadly consistent with the Guidelines (sometimes through using clause 2 of the Guidelines) and the Authority's objective. They have therefore been included in the proposed TPM.

8.8 However, significant choices and questions have come up during our assessment of Transpower's proposals on adjustments. While in most cases the Authority ultimately accepted Transpower's proposals on adjustments for consultation, we think these choices and questions are important and we seek feedback from stakeholders on them. Those questions arise under the following situations:

(a) Entry of new generation – competitive neutrality between generation types.

(b) BBC allocation between new entrant and incumbent – 'whole-of-life' issue.

(c) Definition of 'large' and of 'substantial sustained change in use'.

(d) BBC adjustment for a distributor that increases its use.

(e) BBC for an incumbent that substantially reduces its use.

(f) Exit of a related party.

Entry of new generation – competitive neutrality

8.9 The proposed TPM provides that a new generator's benefit-based charges are based on the charges of comparable existing generators. This is consistent with the TPM Guidelines, which provide that the costs of post-2019 grid investments are to be allocated between customers in proportion to their expected net positive private benefits from those investments. The Guidelines do not specify how expected net positive private benefits are to be assessed.

8.10 We have considered whether setting BBCs for new entrants in this way under the proposed TPM might bias investment against generation with high capital costs and low short-run marginal costs (SRMC), such as renewable generation. Transpower discussed this possibility in its 30 June Reasons paper.[150]

8.11 In our view this issue does not arise for existing generation. When the benefits of a proposed new grid investment are assessed, an existing generator's capital costs are the same in both the factual (with the grid investment) and the counterfactual (without the grid investment) scenarios.[151] So, an assessment of the benefits received from the grid investment based on each existing generator's SRMC will be consistent with competitive neutrality.

8.12 The Authority has seen no evidence of bias in the proposed method for setting charges for new entrant generators. However, we remain open to considering this as a possible risk. We note the proposed TPM requires Transpower to use the clause 52 method if most benefits to supply groups are to new large generators (ie, a benefit-based investment primarily undertaken to allow lower-cost generation to enter the market).[152] The quantity of supply plays a larger role in the clause 52 method (compared to the clause 53 method), and price/cost considerations play a less important role, which would moderate any potential bias for new generation.

8.13 In the context of the clause 53 method, the proposed TPM sets out explicit rules for setting allocations for large plant and new customers that do not initially exist.[153] These rules nevertheless allow Transpower some flexibility in the way it sets charges for new entrants and do not prevent the creation of multiple generation groups for existing and new generators. It remains open to Transpower under the clause 53 method to ensure that two new generators that are identical except for their capex/opex split would also have the same annual BBC.[154]

8.14 For these reasons, in the Authority's view, the proposed TPM does not result in a bias against investment in low-SRMC generation. However, we are interested in submitters' views on this question and on whether the proposed TPM requires further specific rules on how Transpower should assess benefits for a new entrant.

BBC allocation between new entrant and incumbent – 'whole-of-life'

8.15 The proposed TPM provides for Transpower to allocate benefit-based charges for a new entrant (or an incumbent opening a new plant or substantially increasing its energy use) based on the allocation of charges that an equivalent incumbent would pay in the same year.

8.16 This is a departure from clause 33(b) of the Guidelines, which requires Transpower to allocate the BBC to a new entrant (or an incumbent opening a new plant or substantially increasing its energy use) based on the whole-of-life expected benefits it

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150 *Reasons* paper, Chapter 7, section 9.8, para 149-156.

151 Transpower shares this view: see *Reasons* paper, Chapter 7, section 9.8, para 153. Transpower has also expressed concerns about the "practical difficulty of determining the appropriate fixed cost assumptions for existing generator stations that have been connected to the grid for several decades".

152 Refer-back Decision Part 2 Response, 15 September, section 2, page 4-5.

153 Refer-back Decision Part 2 Response, 15 September, section 4.

154 Refer-back Decision Part 2 Response, 15 September, section 4, page 9, para 39. To be clear, the Authority has seen no evidence that such a course of action would be required to avoid bias. However, we note that under the proposed TPM this course of action remains open as a possibility.

gets compared to incumbents. The stylised example in the box on the next page illustrates the difference.

8.17 The difference arises because the proposed TPM provides for Transpower to allocate benefit-based charges for a new entrant (or an incumbent opening a new plant or substantially increasing its energy use) based on the allocation of charges that an equivalent incumbent would pay in the same year. However, cost recovery for grid investments is front-loaded: charges are higher in the early years of an investment's life, and lower later on. Because the new entrant avoids the high charges in the early years, it arguably gains a competitive advantage relative to an equivalent incumbent.

Benefit-based charge for a new entrant – stylised example

This stylised example illustrates the differences between the approach to setting charges for a new entrant provided for in the proposed TPM compared to that in clause 33(b) of the Guidelines. It does so by comparing the charges faced by a new entrant with the charges faced by an otherwise identical incumbent.

Suppose that there is a $120 investment with a 4-year life and benefit-based charges of $42, $34, $26 and $18.[155] There is one incumbent that derives $20 of benefit annually from the investment. A new entrant enters in year 2. Apart from the year it enters, the new entrant is identical to the incumbent and gets identical benefits from the investment, $20 annually, from the year it enters.

Under the 'whole-of-life' approach in clause 33(b) of the Guidelines, the new entrant faces higher charges than the incumbent in years 3 and 4. However, the average annual charge it pays is identical at $20.[156] Under the method in the proposed TPM, the new entrant pays the same as the incumbent in years 3 and 4 ($13 and $9), but a lower annual average charge, $11 as opposed to $24.5.

Year	Benefit-based charge $	Benefits $		Guideline cl 33(b) charges $		Proposed TPM charges $	
		Incum-bent	Entrant	Incum-bent	Entrant	Incum-bent	Entrant
1	42	20		42		42	
2	34	20		34		34	
3	26	20	20	2	24	13	13
4	18	20	20	2	16	9	9
Annual average		20	20	20	20	24.5	11

The Authority has also considered an alternative approach, which would not depart from clause 33(b) of the Guidelines. Under the alternative approach, charges for the new entrant would be set in such a way that any advantage it would otherwise have

155 The decreasing charge is intended to illustrate the decline in real annual charges under the depreciated historical cost depreciation method in the presence of a positive cost of capital and inflation, and for an investment with a much longer life. Other simplifying assumptions are that there are no operating costs, there is no inflation and the cost of capital is zero.

156 The average annual charge is identical because the cost of capital is assumed to be zero. If it were not the annualised charge rather than the average annual charge would be identical.

received due to avoiding high charges in the early years is removed (eg, making the new entrant's average annual charges over the investment's life the same as the average annual charges of an equivalent incumbent). This would mean the new entrant faced higher charges than the incumbent every year from the time it enters. The different approaches and implications for charges are illustrated in the simple example in the box.

8.18 The main advantage of the alternative method is that it is more competitively neutral, when considered over the long run (as opposed to year-by-year). It could also reduce any incentives to defer entry.[157] However, a new entrant will face benefit-based charges for new transmission investments as well as a range of existing investments, so the benefits of adopting a more precise but more complex implementation of clause 33 of the Guidelines are likely to be diluted. The advantage of the approach in the proposed TPM is that it is simpler to implement and more predictable and so better meets clause 1(b) of the Guidelines.

8.19 On balance, the Authority considers that the proposed TPM better meets its statutory objective than fully complying with clause 33(b) of the Guidelines, as the advantages of the latter approach are likely to be limited and because the proposed TPM better meets clause 1(b) of the Guidelines.

Definition of "large" and "substantial sustained change" for adjustments[158]

8.20 The proposed TPM (as required by clause 33(a) of the Guidelines) provides for adjustment to charge allocations when a customer alters the connection of a large plant or when it increases its use in a substantial, sustained way.

8.21 The proposed TPM defines these terms as follows.[159] 'Large' means:

(a) for plant, that the plant—

(i) is connected to the grid; or

(ii) has capacity of at least 10 MW; and

(b) for an upgrade of plant, that the plant's capacity has increased by at least 10 MW compared to the plant's capacity before the upgrade; and

(c) for a de-rating of plant, that the plant's capacity has reduced by at least 10 MW compared to the plant's capacity before the de-rating.

8.22 A substantial, sustained increase is proposed to be an increase in a large plant's expected annual electricity consumption or generation of at least 25% since the last

157 Relatedly, another potential advantage of adopting a version of the 33(b) method is that it could mitigate the first mover disadvantage (FMD) issue – if there were concerns about this issue in the interconnection context – by ensuring that first movers pay no more than later entrants. However, the Authority does not consider this advantage to be material. The FMD issue is potentially material for connection investments, the costs of which would be recovered in a typical case from a single connecting party. By contrast, any FMD issue is unlikely to be material in the interconnection context, where costs are spread across all benefiting parties based on their expected future benefits from the interconnection investment. The FMD issue is discussed at Chapter 4.

158 The term 'large' is used in other contexts elsewhere in the proposed TPM

159 *Reasons* paper, p10.17.

time the relevant customer’s BBI customer allocations for one or more BBIs were calculated, and the increase is sustained, ie, expected to last for at least five years.[160]

8.23 The Authority agrees that quantifying the thresholds in this way reduces uncertainty by giving customers greater clarity about when their charges may be subject to adjustment.[161] The Authority considers it is important that the thresholds strike a balance between being large enough to ensure that the charges remain fixed-like, while being small enough that they do not encourage behaviours aimed at avoiding the charges, (eg, choosing to invest below the threshold to avoid charge adjustments). The Authority seeks feedback on whether the thresholds proposed provide an appropriate balance between these objectives.

Benefit-based charge for a distributor that substantially increases its electricity use

8.24 The proposed TPM treats the connection of a distributor to a new GXP and the upgrade of a transformer at a distributor’s GXP as an adjustment event for benefit-based charges (clauses 89-90).

8.25 This proposal is arguably inconsistent with the strict wording of clause 33(a)(ii) of the Guidelines. That clause – which provides the adjustment for a substantial sustained change in use – is limited to large generators and plant and so excludes incremental growth in local networks.

8.26 However, in the Authority’s view, the reasons for adjusting the benefit-based charge for a large generator or plant would seem to apply equally to a distributor. The Authority also agrees with Transpower that a new GXP and a transformer upgrade appear reasonable thresholds to signify a substantial sustained increase in use. As such, the Authority considers that a departure is justified under clause 2 of the Guidelines, because it is not inconsistent with the intent of the Guidelines and promotes the efficient operation of the industry.[162]

Benefit-based charge for an incumbent that substantially reduces its use

8.27 The proposed TPM provides for an immediate decrease in each relevant benefit-based charge when a party disconnects a plant and also when it undertakes a large de-rating of a plant.[163]

8.28 This provision is partly inconsistent with the strict wording of the adjustments provisions of the Guidelines, which provide for a decrease in each relevant benefit-based charge only when a party disconnects a plant (but do not mention the situation in which it undertakes a large de-rating).

8.29 The Authority agrees with Transpower that this departure from the strict wording of the adjustments provisions is justified under clause 2 of the Guidelines, as it would

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160 *Reasons* paper, p10.18.

161 The Guidelines define ‘large generating station’ and ‘large offtake plant’ as one that is directly connected to the grid or that in Transpower’s opinion is of such a size that it could viably connect directly connect to the grid. ‘Substantial sustained’ is not defined. These adjustments are to be designed to minimise any incentive on a party to inefficiently shift their point of connection to avoid charges and maintain competitive neutrality.

162 *Reasons* paper, page 10.31

163 Proposed TPM, clauses 8, 78, 83.

promote competition and the efficient operation of the industry.[164] In particular, without this provision, competitive neutrality between customers may be adversely affected, and a party may be encouraged to disconnect a plant entirely even when de-rating it would be more efficient.

8.30 A further option would be to also provide for a decrease in BBCs where a party has a substantial sustained decrease in use without closing or de-rating a plant.[165] An argument for this alternative would be that otherwise there could be an incentive to de-rate even when it was more efficient not to do so in order to get the benefit of reduced benefit-based charges. On the other hand, a decrease in energy use is easier to reverse than a de-rating, and it is harder for Transpower to form a view on whether a decrease in use is likely to be sustained. On balance, the Authority considers that such a further amendment is not necessary to ensure consistency with its statutory objective; however, it welcomes feedback from stakeholders on this issue.

Exit of Related Party

8.31 The proposed TPM makes a 'related entity' potentially liable for a party's charges following the exit of a customer (clause 85(7) of the proposed TPM) and the disconnection of a large plant (clause 86(6)).

8.32 Again, this is not explicitly provided for in the Guidelines. However, the Authority agrees any departure from the details of the Guidelines is justified under clause 2 of the Guidelines. It is consistent with the intent of the Guidelines and the statutory objective. Otherwise, if charges and other provisions of the Guidelines applied only to the customer that is the legal entity involved but not any related party, eg, the company that owns a generating plant, but not any other company with the same ownership – this would open up easy avenues to avoid the intent of the Guidelines. For example, 'corporate structuring could be used to avoid the 10-year rule in clause 33(d) of the Guidelines.'[166] The Authority considers it appropriate that the proposed TPM does not create such inefficient avoidance opportunities.[167]

8.33 The Authority is interested in stakeholders' views on this provision, including whether it should be extended to cover other situations and other TPM charges.

Adjustments to the residual charge allocation

Residual charge for new entrant and expanding customer

Proposed approach

8.34 The proposed TPM provides that the residual charge for a new entrant customer 'ramps up' gradually with a lag, such that a new entrant entering in year one begins to pay the residual charge in year 5 and pays a 'full-scale' residual charge from year eight. This is shown as the dashed blue line in Figure 7 below. This approach mirrors

164 *Reasons* paper, para 96.2, page 10.30

165 This would need to be justified by invoking clause 1(c) and clause 2 of the Guidelines.

166 As Transpower notes on page 10.29 of its *Reasons* paper.

167 See also clause 1(c) of the Guidelines.

the treatment of an equivalent existing transmission customer that is expanding.[168] The proposed TPM differs from the TPM proposed by Transpower with respect to this matter.

8.35 The Authority considers that this approach is consistent with the Guidelines, which are relatively flexible with respect to setting a new entrant's residual charge,[169] and that it is necessary to adequately conform with its statutory objective, specifically the competition limb.

8.36 The approach to a new entrant's charges is complicated from a competitive neutrality standpoint. The approach in the proposed TPM avoids any disparity in treatment between a new entrant and an equivalent expanding incumbent. However, it would arguably create a disparity in favour of the new entrant as compared to an equivalent incumbent that was not expanding, since the latter would not have the benefit of the phase in of the residual charge (although it may have earlier when it expanded).

8.37 Overall, the Authority considers that the former disparity is more important to avoid than the latter because:

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

(b) a new entrant could otherwise avoid the charge, possibly at some cost, by structuring its connection arrangements to characterise itself as an expanding incumbent, (ie, essentially seeking to avoid the charge for a period).

8.38 The Authority therefore considers that, to adequately conform with its statutory objective, there needs to be a lag in charges for both expanding existing customers and new customers.

Alternative approach: step change for new entrant

8.39 The Authority also considered an alternative approach, proposed by Transpower on 30 June 2021, under which the new entrant would begin paying a 'full-scale' residual charge immediately with no lag or gradual phase-in.

8.40 The Authority is concerned that an immediate application of residual charges to new entrants would impact investment decisions of new and existing transmission customers differently: a new entrant would face the full residual charge immediately, whereas an expanding incumbent would only face the residual charge after the lagged adjustment applies.

8.41 This would have the effect of making it harder for a new entrant to enter than it would for an incumbent to expand by the same amount and in the same way, for example by opening a new factory. This would distort competition. In addition, it would

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168 This effectively applies the standard provisions related to adjustment of the residual charge at clause 30 of the Guidelines to both new transmission customers and expanding customers.

169 Clause 33(a) of the Guidelines provides separately for increases in use of the grid by new and expanding customers. It explicitly states that the proposed TPM must provide a process for allocating the residual charge to a new entrant. Clause 33(c) further requires that the new entrant's residual charge must 'ultimately' be the same as that of an equivalent incumbent. However, they give no specific guidance as to how the new entrant's residual charge is to be phased in. By contrast, clause 33(b) of the Guidelines provides for the adjustment of the benefit-based charge but not the residual charge of an incumbent that expands its use of the grid. This means that the standard provisions related to adjustment of the residual charge at clause 30 applies, ie, the charge adjusts with a lag and phases in via a moving average.

provide an inefficient incentive for a new entrant to structure itself as an incumbent initially (by connecting to distribution networks or to form joint ventures with existing transmission customers) to avoid the initial step in the residual charge.

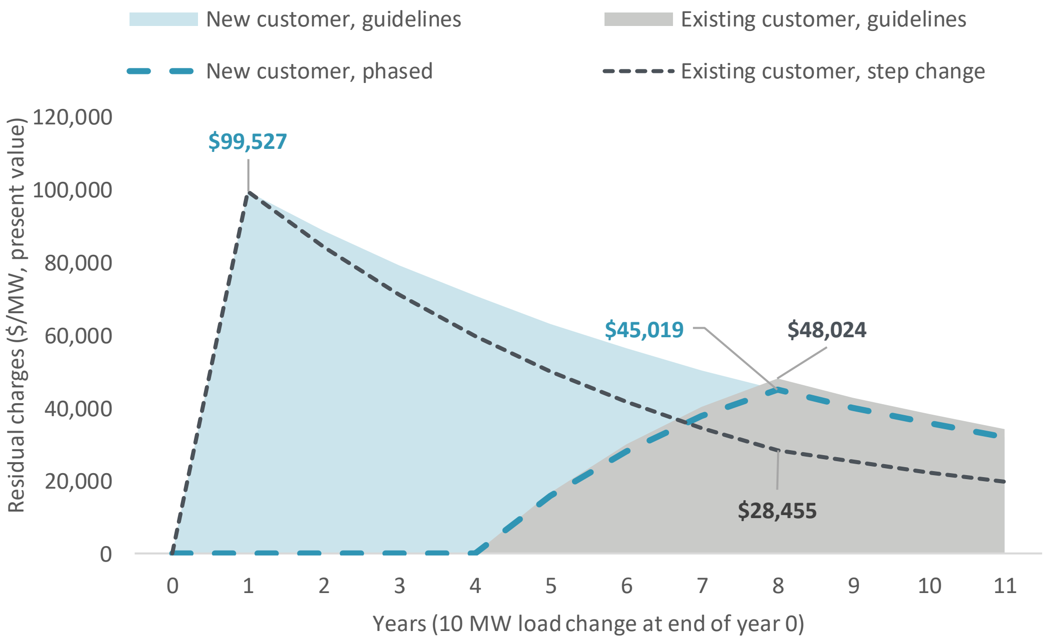
8.42 The nature of the different effects is illustrated in Figure 7, which shows that:

(a) a new customer investing in new electricity consuming plant would begin paying residual charges straight away (the solid blue area in the figure). In this worked example, charges start at $99,500 per MW (roughly the size of current coincident peak demand charges) and then decline gradually over time both because the amount of revenue recovered from the residual charge declines and because values are discounted to present values

(b) an existing customer undertaking an equivalent investment, would not face similar sized charges to the new entrant until seven years after the investment. There would be no increase in residual charges until the fourth year after the investment and the charges only rise to be about the same as a new entrant's by year eight. This is illustrated by the grey area.

Figure 7 Residual charge options – impacts on new v existing customers

Present valued[170] annual residual charges per MW for a 10MW investment in new load.



8.43 The Authority therefore considers that this approach would not adequately conform with statutory objective, particularly the competition limb; however, welcomes any feedback from stakeholders on this approach.

Alternative approach: step change for all customers

8.44 The Authority also considered another alternative approach, proposed by Transpower on 25 August (in their response to the Authority's Refer-back Decision part 1), under which the residual charge for both the new entrant and the incumbent

170 An 8% discount rate has been used.

increase immediately as a step change following an increase in use of the grid. This is shown as the dashed black line in Figure 7.

8.45 Transpower considers that this 'would also address the competitive neutrality problem for all load customers (new, existing with new load, and existing with existing load) and ensure a level playing field for potential competition between modes of connecting large consuming plant, particularly grid connection versus embedded connection.' The Authority agrees that it would have this effect. Transpower clearly illustrates this in a helpful Appendix which compares its proposed approach with the approach provided for in the proposed TPM and in the Guidelines.[171]

8.46 However, the Authority considers that this option is unlikely to adequately conform with the Authority's statutory objective, in contrast to the lagged adjustment to the charges set out in the proposed TPM. This is because it would defeat the purpose of the lag in the adjustment of the residual charge provided for in the Guidelines. This lag is intended to be sufficiently long to avoid inefficient incentives on customers to take action to avoid this charge – the residual charge is not meant to influence customers' grid use decisions.[172]

Residual charge: large party exit and large plant disconnected

Proposed approach

8.47 When a customer exits entirely, (ie, stops drawing electricity from the grid), it is no longer liable for transmission charges. The proposed TPM provides that when a large plant disconnects (whether directly connected or embedded), its residual charge in respect of that plant also ceases; that is, the residual charge in respect of that plant is adjusted in a manner parallel to an exiting customer. This ensures that there is equivalent treatment as between a smaller party that exits completely and a larger party that closes a comparable plant.

8.48 The Authority is interested in stakeholders' views on whether this should be extended to large deratings, as with the benefit-based charge. This would avoid creating an incentive to close a plant when it is more efficient to de-rate it.

8.49 The proposed approach does however risk creating an inefficient incentive for a customer who is considering downsizing a plant to close it entirely. This is because, if the customer merely downsized the plant, it would continue to pay residual charges, which would be lagged by 4-8 years, so it would only see the effects of downsizing on its charges after that period. By contrast, if it closed the plant completely, it could avoid the related residual charge entirely.

8.50 So the Authority is also considering the alternative of not providing for separate adjustment of the residual charge of a customer who closes a plant but continues to draw electricity from the grid. In that case, the lagged adjustment of the residual charge would mean that the customer's residual charge would eventually adjust to be the same as an otherwise equivalent exiting customer, but only after a lag of 4-8 years. It would therefore introduce some disparity in treatment between plant closure and customer exit. However, it would mitigate the inefficient incentive the currently

171 *TPM Proposal Refer Back Decision Part 1 Response*, page 13 and Appendix 1.

172 *Transmission Pricing Methodology: 2019 Issues Paper: Supplementary Consultation*, 11 February 2019, available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c18337

proposed TPM may provide for a customer to close a plant rather than de-rate it or to reduce output without downsizing.

8.51 If the Authority adopts this approach, it would need to consider how to treat the exit of an embedded party; that is, whether the exit would be treated as a downsizing of the customer the party is connected to (so the customer's residual charge would adjust with a lag) or whether to look through the customer to recognise the exit (such that the customer's residual would adjust immediately). The latter could be achieved by adopting a provision similar to that in the equivalent benefit-based charge adjustment provision, which provides that where a large plant owner, or a related entity, remains a transmission customer, the disconnected plant's charges are attributed to them.

8.52 In addition, if the Authority provides a different residual charge adjustment for a downsizing party relative to an exiting party, it would also need to consider whether it should also apply to a related entity, as is the case for adjustments to the benefit-based charge for an exiting party. This would discourage corporate restructurings from being used to avoid the residual charge, at some cost in terms of increased complexity.

Reassignment

8.53 The Authority intends that the proposed TPM would require Transpower to reduce the BBC for a transmission investment in certain circumstances if the investment turns out to be a 'white elephant' and customers make significantly less use of it than Transpower had originally anticipated. This is achieved by reducing the value of the relevant grid assets for the purpose of calculating benefit-based charges in respect of that investment. The intention is to ensure that future benefit-based charges paid for the investment better reflect the benefit to the customer (and so the charges that would have paid had the investment been sized more appropriately).

8.54 The provisions of the proposed TPM in this area contain a departure from the strict wording of the Guidelines. Clause 40(b) of the Guidelines provides for Transpower to adjust the allocations between customers as necessary after a reassignment to take account of the changes that led to reassignment. Transpower considers there is no need for such an additional provision regarding reallocation, in part because reallocation will rarely if ever be an appropriate response to oversizing, and in any event because the adjustment provisions capture events, (eg, a large customer exiting) that could result in over-sizing and because the provision is inconsistent with the allocations being fixed-like. Thus, reallocation of charges between customers (in contrast to the reduction of the covered cost for a BBI) is unlikely to be needed.

8.55 The Authority agrees with Transpower that a departure from the Guidelines is justified under clause 2 of the Guidelines, and that providing separately for adjusting the allocations in the reassignment provisions is unnecessary.

Consultation questions

Do you agree with or have any other feedback on the proposed provisions for adjusting transmission charges?

The Authority welcomes feedback on any aspect discussed or proposed in this chapter, including whether:

- the proposed TPM should provide more detail on the method for determining new entrants' benefits
- the charges for a new entrant should be the same as an equivalent incumbent each year (as in the proposed TPM), on a whole-of-life basis as in the Guidelines
- the proposed thresholds for 'large' and 'substantial sustained' change in grid use are appropriate
- the connection of a distributor to a new (and additional) GXP and the upgrading of a transformer at a distributor's GXP should be adjustment events
- the plant disconnection provision should be extended to plant de-rating
- the relevant provision should be further extended to cover a substantial sustained decrease in grid use not related to a plant disconnection or de-rating
- the proposed 'related entity' provisions deal appropriately with avoidance concerns, and whether there is a case for a broader or more general 'related entity' provision to deal with other, potentially unforeseen, avoidance opportunities
- the residual charge for a new entrant and an expanding customer should adjust with a lag and a gradual ramp-up, as proposed
- the proposed TPM should include a specific provision for the adjustment of the residual charge of a large customer that closes a plant (either to allow its adjustment immediately or in some other way), or should the standard lagged adjustment of the residual charge apply? If the former, should the provision be extended to deratings? If the latter, should it apply to embedded parties and should there be a related entity provision?
- a new related entity provision should be provided for the residual charge.

9 Prudent discount policy

9.1 The proposed prudent discount policy (PDP) allows Transpower to discount the transmission charges of designated transmission customers by approving:

(a) an inefficient bypass prudent discount (IBPD), or

(b) stand-alone cost prudent discount (SACPD).[173]

9.2 The purpose of an IBPD is to help ensure the proposed TPM does not provide incentives for a customer to invest in an alternative project to reduce their transmission charges, by bypassing existing grid assets, where that investment would increase total economic costs, resulting in an 'inefficient bypass' of the grid.[174]

9.3 The purpose of a SACPD is to help ensure the proposed TPM does not result in a customer paying transmission charges that exceed the efficient stand-alone cost of the transmission services the customer receives from interconnection assets.[175]

9.4 The Authority considers the proposed PDP provisions submitted to the Authority on 15 September 2021 are consistent with the Guidelines and its statutory objective. This is for the reasons set out in Transpower's Reasons paper, and Transpower's response to the Authority's request that it reconsider some aspects of the proposal submitted on 30 June 2021.[176]

9.5 The Authority seeks feedback on the PDP provisions in the proposed TPM, in particular whether the proposed TPM adequately prescribes the fundamental aspects of the PDP.

9.6 The Authority is also seeking feedback on potential amendments identified in the following three areas, which the Authority considers may better promote the Authority's statutory objective:

(a) Preparation of a prudent discount practice manual (PD practice manual).

(b) The maximum period for the term of a prudent discount and for the prudent discount calculation period.

(c) Whether a customer should be able to terminate an SACPD agreement.

Relevant sections in the Guidelines and proposed TPM

Guidelines	Proposed TPM
Clause iv, clause 45-48	Part I: Clause 116-128: common rules
	Clause 129-134: inefficient bypass
	Clause 135-139: stand-alone costs
	Clause 140: funding of prudent discounts

173 Refer to clause vi. of the TPM Guidelines.

174 Clause 129 of the proposed TPM.

175 Clause 135 of the proposed TPM.

176 See chapter 13 and compliance matrix in Appendix G of the *Reasons* paper, and Transpower's 25 August 2021 submission to the Authority, pp. 15-16.

The proposed TPM prescribes fundamental aspects of the PDP

9.7 The Authority considers the proposed TPM provides a reasonable and appropriate level of prescription on all structural and fundamental aspects of the PDP. The Authority considers this would provide sufficient information to promote regulatory certainty for stakeholders on the key tests and matters that Transpower must consider when assessing a prudent discount application.

9.8 In particular, the proposed TPM sets out:

(a) the matters Transpower must consider in assessing whether an alternative project proposed in a prudent discount application would provide the same, or a substantially similar, level of service to the customer as the transmission services currently received by the customer[177]

(b) the matters Transpower must consider when calculating the costs of an alternative project proposed in a prudent discount application[178]

(c) the test of whether an alternative project proposed in a prudent discount application is commercially beneficial for the customer[179]

(d) the tests Transpower must use in assessing whether an alternative project is technically and operationally feasible for the customer, and is consistent with good electricity industry practice[180]

(e) the test Transpower must use in assessing whether the alternative project in an IBPD application is inefficient[181]

(f) the test Transpower must use in assessing whether the stand-alone investment in an SACPD application is efficient.[182]

9.9 The Authority therefore considers that the PDP section of the proposed TPM is consistent with the Guidelines (and its statutory objective). However, it welcomes any feedback stakeholders may have on this section.

Preparation of a prudent discount practice manual

9.10 Under the proposed TPM Transpower *may* publish a PD practice manual.[183] This would contain detailed methodologies and assumptions for the PDP, which if placed in the proposed TPM could make it overly cumbersome.

9.11 The Guidelines do not specify that the proposed TPM must require the publication of such a manual but it is not inconsistent with the Guidelines.

9.12 The Authority is interested in stakeholders' feedback on whether the proposed TPM would better promote the Authority's statutory objective if it provided that Transpower *must* publish a PD practice manual, with this initial manual containing at least the following:

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177 Clauses 46b and 47b of the Guidelines reflected in clause 119(2) of the proposed TPM.

178 Clauses 46b, 47a, and 47b of the Guidelines, reflected in clause 120 of the proposed TPM.

179 Clause 46a of the Guidelines, reflected in clause 121 of the proposed TPM.

180 Clause 46a of the Guidelines, reflected in clauses 131 and 136 of the proposed TPM.

181 Clause 46b of the Guidelines, reflected in clause 132 of the proposed TPM.

182 Clause 47a of the Guidelines, reflected in clause 137 of the proposed TPM.

183 Clause 128(1) of the proposed TPM.

(a) the content requirements for a prudent discount application[184]

(b) a description of the optimisation test(s) Transpower would use in assessing whether the stand-alone investment in an SACPD application is efficient[185]

(c) how Transpower would estimate the costs of obtaining property rights, easements, and resource consents for alternative projects[186]

(d) the methodology Transpower would use to determine:

  (i) electrical losses[187]

  (ii) operational feasibility[188]

  (iii) compliance with asset owner performance obligations, technical codes, and other relevant requirements of Part 8 of the Code[189]

(e) key assumptions.

9.13 The Authority would be interested in stakeholders' feedback on when they would find it useful to see a PD practice manual. Publication of a PD practice manual within a defined period and containing minimum content could promote regulatory certainty and so better promote the Authority's statutory objective than a more permissive clause would. Participants would be more informed when considering the merits of applying for a prudent discount. They would also be expected to avoid transaction costs that might otherwise result in the absence of a manual providing information on how Transpower will assess prudent discount applications, (eg, participants undertaking unnecessary assessments/analysis). Specifying minimum content in the initial manual would be consistent with practice elsewhere in the Code.

9.14 On the other hand, Transpower has noted '(t)he efficacy of developing and publishing a prudent discount practice manual may depend on the number of prudent discount applications we receive (or expect to receive).'[190] The Authority considers this view has significant merit. It highlights the trade-off that must be factored into a decision on whether to publish a PD practice manual in advance of any prudent discount applications, being the possibility of:

(a) Transpower incurring unnecessary, and therefore inefficient, costs because no customer is intending to consider a prudent discount application

(b) customers incurring unnecessary, and therefore inefficient, costs because of an absence of information on how Transpower will assess prudent discount applications.

9.15 The Authority notes that Transpower intends to publish the application requirements and application fee for prudent discounts before any new TPM comes into effect.

9.16 We also note the suggested minimum requirements for an initial PD practice manual listed above provide Transpower with a reasonably significant amount of discretion

184 Clause 117(2)(a) and the definition of 'application requirements' in clause 3 of the proposed TPM.

185 Clause 137(1)(c) of the proposed TPM.

186 Clauses 131 and 136 of the proposed TPM.

187 Clause 120(2) of the proposed TPM.

188 Clauses 131 and 136 of the proposed TPM.

189 *Ibid*.

190 *Reasons* paper para 86, page 13.14

over the level of detail to be included in the initial manual. Transpower's decision in this regard could be informed by liaison with participants.

Transpower need not be bound by the prudent discount practice manual

9.17 Under the proposed TPM the PD practice manual is not binding on Transpower.

9.18 The Authority's initial thinking on this matter was that regulatory certainty would be promoted if Transpower were to be bound by the PD practice manual, limiting Transpower's ability to exercise discretion.[191]

9.19 If Transpower needed to update its assumptions and detailed methodologies during an assessment of a prudent discount application, we believed Transpower should be able to consult on these changes without breaching its obligation to consider a prudent discount application within a reasonable timeframe.[192]

9.20 The Authority is now comfortable with the PD practice manual not binding Transpower but is interested in stakeholders' views on this point.[193] The Authority's key reasons for accepting the manual need not be binding are as follows:

(a) All structural and fundamental aspects of the PDP would be in the TPM.

(b) Transpower must consult on its draft decision to approve/reject a prudent discount application, including any material departures from the assumptions and methodologies in the PD practice manual and the reason for those departures.[194]

(c) Transpower must publish with its decision to approve/reject a prudent discount application any material departures from the assumptions and methodologies in the PD practice manual and the reason for those departures.[195]

(d) The PD practice manual is likely to be a 'work-in-progress' for some time after any new TPM comes into effect - particularly given the impact on the PDP of the significant changes required by the Guidelines, and the inclusion of SACPDs in the PDP.

(e) A prudent discount applicant has the option of seeking an independent expert review of any aspect of Transpower's decision on a prudent discount application,[196] with the independent expert able to require Transpower to meet all or some of the expert's costs if an aspect of Transpower's decision under review was unreasonable.[197]

15 years as the *default* maximum period, but longer term possible

9.21 The proposed TPM says that 15 years is:

191 See the Authority's letter to Transpower, dated 12 March 2021, in response to Transpower's TPM Checkpoint 2B submission, at p. 4.

192 Clause 16 of the proposed TPM.

193 Clause 128(5) of the proposed TPM.

194 Clause 122(2)(a) of the proposed TPM.

195 Clause 126(c) of the proposed TPM.

196 Clause 123(3) of the proposed TPM.

197 Clause 123(5) of the proposed TPM.

(a) for an IBPD, *the maximum period for the term* of a prudent discount and for the prudent discount calculation period

(b) for an SACPD, *the term* of a prudent discount and the prudent discount calculation period.[198]

9.22 The rationale provided for a maximum 15-year term is that the conditions in the power system may change in ways not anticipated when a prudent discount is approved and that a customer can apply to renew their prudent discount agreement before it expires.[199] Under the current TPM the duration of a prudent discount is the lesser of the remaining economic life of the grid assets affected by the agreement or 15 years.[200]

9.23 However, the Authority is also aware that the economic life of an applicant's alternative project may be longer than 15 years, so that uncertainty about whether a prudent discount agreement will be renewed could cause inefficient outcomes. The applicant may decide to invest in their alternative project rather than rely on the prudent discount.

9.24 The Guidelines do not specify a maximum term for an IBPD or an SACPD. The Guidelines left 'the duration of a prudent discount unspecified, so that it is to be agreed via commercial negotiation between Transpower and its customer'.[201] We noted at the time that disagreement between Transpower and its customer on the length of a prudent discount could be resolved using an independent expert.

9.25 Given these considerations, the Authority is interested in stakeholders' feedback on whether the proposed TPM should be amended so that it makes 15 years the *default* maximum period for the term of a prudent discount and for the prudent discount calculation period.

9.26 Under such an amended approach, transmission customers applying for a prudent discount (either an IBPD or an SACPD) would be permitted to apply for a prudent discount that is for a term longer than 15 years where this reflects the economic life of the alternative project. Applicants would need to demonstrate the need for the longer prudent discount term (and associated prudent discount calculation period).

9.27 This alternative proposal is consistent with Transpower's preliminary view following its consultation with interested parties in October 2020.[202] Transpower changed its early thinking about leaving for negotiation the term of a prudent discount to avoid the term possibly being a point of contention / dispute when agreeing the prudent discount agreement with the customer.

9.28 The reason to adopt 15 years as a *default* maximum period for the term of a discount would be to reduce the risk of inefficient bypass, and so would better promote the Authority's statutory objective. This is because customers considering alternative projects with economic lives longer than 15 years would be able to negotiate a

198 Clause 124(3) and the definition of 'prudent discount calculation period' in clause 3 of the proposed TPM.

199 See *Reasons* paper, para 59, p. 13.11

200 See clause 41(3) of Schedule12.4 of the Code.

201 See the Authority's TPM Guidelines Decision Paper, June 2020, paragraphs 12.10-12.11, p. 76.

202 Transpower NZ, December 2020, TPM Development Prudent Discount Policy consultation: Summary and response, pp. 4-5.

prudent discount for a longer term and not face uncertainty over whether a prudent discount would be renewed. Removing this uncertainty would, in turn, reduce the likelihood of the customer investing in its alternative project and increasing total economic costs.

9.29 There are, however, incremental transaction costs associated with varying from a standard term for an SACPD. The Authority considers these would relate primarily to negotiation costs in instances when Transpower disagreed with the term proposed by the prudent discount applicant. Such incremental transaction cost would be offset by the avoided cost of SACPD renewal applications.

9.30 As the term of an IBPD is a maximum of 15 years, incremental transaction costs in the form of negotiation costs may or may not arise for an IBPD under the Authority's proposal. That is, Transpower and the IBPD applicant may have negotiated a term shorter than 15 years.

9.31 Transpower can reflect its additional transaction costs in the application fee for a prudent discount application that varies from the default 15-year term.[203] The applicant can then factor this into their assessment of the net benefit to them from using a term other than the default term.

Prudent discounts funded through the residual and benefit-based charges

9.32 The proposed TPM provides that each prudent discount is to be funded by:

(a) customers that are beneficiaries of the investments for which the recipient of the prudent discount pays benefit-based charges, and

(b) load customers paying the residual charge.

9.33 Each customer's contribution to funding a prudent discount would be proportional to their share of:

(a) the benefit-based charges in respect of investments for which the customer receiving the prudent discount also pays such charges, and

(b) the residual charge.

9.34 The Guidelines do not specify how prudent discounts are to be funded. Transpower consulted with interested parties on three funding options in October 2020, These options, and a summary of which stakeholders supported which option, are set out in Transpower's Reasons paper.[204] Transpower's proposal was identified after Transpower's review of stakeholder feedback (including feedback from the Authority) on those three options.

9.35 The Authority considers the proposed approach is consistent with the intent of the Guidelines and with its statutory objective.

9.36 The Authority considers the proposed funding option achieves the best practicable trade-off between ensuring that the covered cost of benefit-based investments is recovered through benefit-based charges and ensuring transmission charges are

203 Clause 16 of the proposed TPM.

204 See *Reasons* paper, para 138-139, pp. 13.22-13.23

based on net private benefits[205] and limiting the distortionary effects of transmission charges levied to fund prudent discounts. These distortionary effects are limited by spreading the charges over a large pool of customers and limiting the extent to which generators subject to a prudent discount charge[206] are likely to incorporate the charge in their offers.[207]

9.1 Transpower has published a simple, stylised worked example of changes to hypothetical transmission customers' benefit-based and residual charges under an SACPD.[208]

Stand-alone cost limb of the PDP

9.2 The Authority seeks stakeholders' feedback on whether a customer receiving an SACPD should be able to terminate their SACPD agreement with Transpower.

Transpower can terminate prudent discount agreements

9.3 The proposed TPM gives Transpower the right to terminate an IBPD agreement or an SACPD agreement if a condition of Transpower's approval of the prudent discount is not, or ceases to be, satisfied.[209]

9.4 This provision addresses a concern that conditions applying when a prudent discount is agreed may not be enduring.[210] This was reiterated in a submission on Transpower's PDP consultation paper.[211]

Should a customer be unable to terminate an SACPD agreement?

9.5 The proposed TPM permits a customer to terminate its SACPD agreement with Transpower.

9.6 The reason is that giving a customer the right to terminate an SACPD agreement on six months' notice 'is appropriate given the entirely hypothetical nature of the alternative project for a SACPD…and the potential for the customer to be better off without the prudent discount agreement at some point during its term.'[212]

9.7 The Guidelines do not specify whether prudent discount agreements can be terminated by the parties to the agreement. The proposed approach of enabling a customer with a SACPD agreement to terminate the agreement is inconsistent with

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205 See *Reasons* paper, para 143, p. 13.23

206 Ie, the generator is a beneficiary of the grid investment(s) for which the prudent discount recipient pays benefit-based charges.

207 The PD charge is likely to vary across the generators, based on their varying benefits from the grid investment. We note a generator operating in a competitive market such as the New Zealand electricity market has little scope to pass on a cost increase that only affects itself (rather than all generators).

208 See Transpower's 15 September 2021 submission to the Authority:

Appendix F: Explanatory Guide - Adjustments and Prudent Discount Policy, pp. F24-28, and

Supporting information for Appendix F - Adjustments and Prudent Discount Policy worked example (spreadsheet labelled "9. SACPD").

209 Clause 123(2)(c) of the proposed TPM.

210 Electricity Authority. Transmission pricing methodology 2020 Guidelines and process for development of a proposed TPM – Decision, 10 June 2020, paragraph 12.9, p. 76.

211 See Northpower's response to question 3.1 in Transpower's PDP consultation paper (p. 4 of Northpower's submission).

212 See *Reasons* paper, para 61, pp. 13.11-13.12.

the proposed approach for an IBPD agreement, under which the customer has no right to terminate the agreement.[213]

9.8 The reason for a customer being unable to terminate an IBPD agreement is to place the customer in a similar position under an IBPD agreement to that which they would be in if they made the alternative investment to bypass the grid. As Transpower notes in its Reasons paper, 'an IBPD would be granted on the basis the customer would build the alternative project otherwise, in which case the customer would be stuck with the alternative project for at least the term of the prudent discount agreement."[214]

9.9 As such, the Authority seeks stakeholders' feedback on an alternative approach whereby a customer with an SACPD agreement with Transpower does not have the right to terminate the agreement.

9.10 The Authority believes the commercial discipline on a customer applying for an SACPD should reflect reality as closely as possible. This suggests a customer with an SACPD agreement should be committed to the agreement for its full term, as for an IBPD, and not have the right to terminate the agreement. The Authority considers this approach aligns better with ensuring an appropriately high threshold is met before an SACPD is approved,[215] thereby reducing the possibility of the SACPD being a subsidy. In this way, this option would be more likely to better promote the Authority's statutory objective.

Consultation questions

Do you have any comments on the proposed PDP provisions? The Authority welcomes comment on any aspect of the proposal, including whether:

- the proposed TPM adequately prescribes the fundamental aspects of the PDP
- Transpower should have to prepare a PD practice manual, and if so when, and should it be binding on Transpower
- 15 years should be the default maximum period with a longer term possible on proof
- prudent discounts should be funded via the residual charge and as appropriate the benefit-based charge
- customers should be able to terminate a prudent discount agreement before the end date of the agreement?

213 Clause 123(2)(d) of the proposed TPM.

214 See *Reasons* paper, footnote 18, p. 13.11.

215 See *Reasons* paper, p. 13.12.

10 Transitional congestion charge

10.1 The Guidelines provide for a Transitional Congestion Charge (TCC) to be included in the proposed TPM if Transpower considers that, without it, grid demand would not be efficiently controlled by other means, including nodal pricing and administrative load control associated with scarcity pricing (Additional component D).

Relevant sections in the Guidelines and proposed TPM

Guidelines	Proposed TPM
Clause viii (d): transitional congestion charge	No provisions in the proposed TPM
Clause 54, 58-61: Additional component D	

Proposed TPM does not include a TCC

10.2 As the Authority has previously set out,[216] the Authority's view is that nodal pricing provides an appropriate market-based signal of the cost of using the grid and therefore that a permanent transmission peak charge is not required. Real-time pricing, combined with emerging technologies and new business models, (eg, flexibility trading) that can be very responsive to price signals, are expected to make this an increasingly effective and efficient way to manage grid congestion.

10.3 The Authority has however provided for the TCC as an additional component to give Transpower another tool to manage congestion should existing mechanisms prove insufficient.

10.4 The TCC provides an option to respond to the concern previously expressed by stakeholders that, without a peak transmission charge, there could be a sudden increase in demand at peak times and that this would create operational issues and inefficiently bring forward transmission and distribution investments.

10.5 Notwithstanding its view around nodal pricing, the Authority acknowledged in March 2020 that some uncertainty exists around how the market will respond to the removal of the RCPD peak signal. It therefore considered there may be value in Transpower being able to use a TCC, particularly as some of the market mechanisms for responding to congestion may still be developing for a period after the implementation of any new TPM.[217]

10.6 The proposed TPM does not include a transitional congestion charge. The reasons are summarised in the next section. But, in brief, Transpower concluded that, any heightened short-term congestion risk from removal of the RCPD charge can be effectively controlled through the tools available to the system operator and grid owner, and this can be done in a way that limits load shedding, ensures the grid is secure, and efficiently limits the impacts on consumers.[218]

216 See the Authority's 2019 Issues paper, the 2020 Decision paper and the Authority's March 2020 information paper, Peak charges under proposed TPM Guidelines, available at https://www.ea.govt.nz/assets/dms-assets/26/26542Peak-charges-under-proposed-TPM-guidelines-information-paper-and-next-steps-March-2020.pdf

217 For example, real time pricing in the wholesale electricity market is scheduled to be implemented from late 2022, and it may take time for demand to fully participate in this market in response to these changes.

218 *Reasons* paper, p15.15, para 56

10.7 Transpower is still able to propose a transitional congestion charge later, via an operational review of the TPM.[219] The Authority expects that Transpower would keep the TCC under review, particularly around the time of transition to any new TPM.

Analysis

10.8 Transpower concluded that it could not make the case that including a TCC in its TPM proposal would better promote the Authority's statutory objective (chapter 15 of Transpower's Reasons Paper). This was because it considered that:

(a) near-term congestion risk is highly uncertain, including because participants' response to impending market developments cannot be confidently predicted

(b) the tools available to the system operator and grid owner give sufficient controls to mitigate short-term elevated congestion risk.

10.9 In its qualitative assessment,[220] Transpower found that:

(a) the absence of an RCPD charge will increase congestion risk, but is unlikely to result in widespread congestion across the grid

(b) for regions or localities with known or expected issues, solutions to manage those issues are already in place or well-progressed

(c) the grid owner and system operator have a suite of tools to mitigate congestion risk, and these are sufficient for short-term management of any unanticipated and relatively frequent congestion.

10.10 The suite of tools include dispatch, forecast schedules and notices that inform and forewarn participants of energy or capacity issues (allowing voluntary actions), administrative load control and grid support and demand response contracts.

10.11 Transpower noted any practical TCC would likely result in load sometimes being shed unnecessarily by participants, while relying on the wholesale market and its own controls would avoid unnecessary load shedding and keep the grid secure.

10.12 The Authority accepts Transpower's conclusion to not include a TCC in the TPM that it proposed.[221] In coming to this view, the Authority considered Transpower's qualitative assessment of the risks and available mitigations summarised above. The Authority also recognised:

(a) the implementation of real time pricing, which will provide location-based scarcity pricing in quarter four 2022, and support more diverse participation in dispatch in quarter one of 2023. This will improve price signals and market participants' responses to those signals

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219 See also *Reasons* paper p 15.16, para 58

220 See *Reasons* paper chapter 15, including para 35-61 at pp 15.10-15.17

221 This conclusion is not affected by the power outages of 9 August 2021, the causes of which are subject to separate reviews which will identify any necessary actions. The Authority has completed phase one of its review, which identified a number of communication and operational issues and made recommendations for the system operator to action. https://www.ea.govt.nz/assets/dms-assets/28/Immediate-assurance-review-of-the-9-August-2021-demand-management-event.pdf In implementing the recommendations in the Authority's 9 August report, Transpower will ensure that its processes efficiently limit the impacts of any load shedding on consumers. On that basis, the conclusions of the Authority's report are consistent with the analysis on the TCC in this chapter.

(b) analysis showing that while removing the RCPD charge would reduce the total projected winter capacity margin around the first year of implementation, it was not likely to cause general operational difficulties (Concept Consulting 2020)[222]

(c) additional recent analysis by Transpower of the impact on peak winter load of effectively removing the RCPD price signal after 31 August 2021, which arrived at similar impacts as Concept's 2020 analysis (Transpower July 2021)[223]

(d) evidence that most distributors would continue ripple control, at least in the near term, to manage their own network peaks, and thus it will continue to be available should the system operator need it at times of congestion.[224] Distributors are also increasingly improving their own price signals, which, through technology and flexibility traders helps with demand response options.

10.13 Transpower considered other design options during the development process, such as a charge based on the existing RCPD charge to achieve a phased transition between the current and any new TPM.[225] However, as described in the Reasons paper, charges that are broad-based and not focused on congestion risk, (ie, targeted at areas, circuits or other circumstances where there is a significant likelihood of congestion without such a charge) are unlikely to be consistent with the Guidelines in relation to the TCC. The Authority also considers such options are unlikely to be consistent with its statutory objective for the same reasons as any unnecessary TCC might be inconsistent, as summarised below.

10.14 The proposal not to include a TCC is consistent with the Guidelines. There is no reason to conclude that including a TCC would better promote the statutory objective, while an unnecessary TCC could harm the promotion of the statutory objective:

(a) A TCC on top of nodal prices would distort/overstate the short run marginal cost of using the grid to access electricity, stymieing competition between grid-supplied and embedded generation, and increasing local prices for consumers.

(b) A TCC is not needed to manage reliability issues, because Transpower, as system operator and grid owner, has the tools to effectively manage material congestion risk and limit involuntary load-shedding to only when and where it is necessary. Transpower is best placed to decide whether it needs another tool to manage congestion, and decided it didn't.

(c) Wholesale market prices and system operator controls together provide efficient and effective ways to manage congestion risk, through efficient signals of transport cost and control of grid demand. An additional price signal is only efficient if nodal prices do not provide a good signal of transport or congestion costs, otherwise it will distort grid use and investments. In practice a TCC may

222 Concept Consulting, Winter capacity margin – potential effect of possible changes to transmission pricing, February 2020, available at https://www.ea.govt.nz/assets/dms-assets/26/26541Concept-Winter-capacity-margin-Feb-2020.pdf

223 Transpower, TPM – Removal of Regional Coincident Peak Demand Outcomes for the System Operator, July 2021, available at https://www.transpower.co.nz/sites/default/files/bulk-upload/documents/TPM%20-%20Removal%20of%20RCPD.pdf

224 Power System Consultants NZ (PSC), Ripple control of hot water in New Zealand, Sept 2020, prepared for EECA, available at https://www.eeca.govt.nz/assets/EECA-Resources/Research-papers-guides/Ripple-Control-of-Hot-Water-in-New-Zealand.pdf?utm_source=newsletter&utm_medium=email&utm_campaign=energy-news-newsletterd

225 *Reasons* paper, pp 15.16-15.19

also be difficult to target well, risking unnecessary demand curtailment. Using grid owner and system operator tools to manage short term congestion issues would avoid unnecessary load shedding and ensure the grid is secure.

10.15 The Guidelines provide the option to introduce a TCC later, as part of an operational review provided for by the Code (clause 61).

10.16 The Authority agrees with Transpower that the threshold for the inclusion of the additional component is not met.

Consultation questions

Do you have any feedback on the proposal not to include a TCC in the proposed TPM, for the reason that widespread risk of congestion from removing the RCPD charge is unlikely and that, if necessary, the grid owner and system operator have effective tools to manage the power system quickly and efficiently?

If not, how should a TCC be designed to be consistent with the Guidelines? Under what situations should it be applied and how should its size and allocation be determined?

11 kVAr charge

11.1 A kVAr (kiloVolt Ampere reactive) charge would charge those that cause a deterioration in the power factor, to reflect the cost they impose on other grid users.

11.2 The Guidelines require a kVAr charge to be included in the proposed TPM if Transpower considers this would better meet the Authority's statutory objective (Additional component G).

Relevant sections in the Guidelines and proposed TPM

Guidelines	Proposed TPM
Clause viii (g): kVAr charge	No provisions in the proposed TPM
Clause 54, 65: Additional component G.	

Proposed TPM does not include a kVAr charge

11.3 Transpower has not included a kVAr charge method in the TPM that it proposed as:

> 'static voltage stability concerns can generally be managed by relatively low cost transmission components (capacitors and reactors)…[and]…a kVAr charge would add significant complexity (and so development and implementation cost) to the new TPM that is unlikely to be offset by material efficiency or reliability benefits.'[226]

11.4 The Authority consider Transpower is well placed to assess these trade-offs and has no information to suggest a kVAr charge would better promote the statutory objective. It is interested in stakeholders' views on this matter. The Authority notes that it would be open for Transpower to propose a kvar charge later as part of an operational review, should it consider in time that a kVAr charge would better promote the Authority's statutory objective.

Assessment against the Authority's statutory objective

11.5 The proposal to not include a kVAr charge is consistent with the Guidelines in that there is no reason to conclude that including a kVAr charge would better promote the statutory objective:

- **competition:** the Authority is not aware of any material direct implications
- **reliability:** Transpower has stated it can effectively manage static voltage stability concerns without a kVAr charge using relatively low cost transmission components, and that a kVAr charge may not necessarily be effective for all reactive power issues
- **efficient operation**: other relatively low cost solutions are generally available to manage any reactive power issues, while a kVAr charge would add complexity without necessarily being effective under all situations.

Consultation questions

Do you have any comment on the proposal not to include a kVAr charge in the proposed TPM?

226 Para 19, page 14.7 of *Reasons* paper

12 Indicative prices

12.1 The proposed TPM rebalances transmission charges between customers. This chapter covers:

(a) indicative prices under the proposed TPM for 2021/22

(b) the impact of the transitional cap on transmission charges

(c) the impact of these indicative charges on typical household bills.

12.2 Any new TPM would not immediately affect the total amount charged for transmission services – Transpower's maximum allowable revenue is determined by the Commerce Commission and is not affected by how it is recovered under the TPM.

12.3 While this section focuses on indicative charges for 2021/22, the structure and level of customers' transmission charges would evolve under the proposed TPM, as existing assets are renewed (gradually reducing the amount recovered through residual charges) and new investments expand the network (increasing benefit-based charges).

Indicative prices under the proposed TPM

Indicative prices are calculated for the 2021/22 pricing year

12.4 Transpower has prepared indicative prices that would apply under the proposed TPM for the 2021/22 pricing year. This is to illustrate the expected impact on customers' charges compared to actual charges for this year under the current TPM.[227] [228]

12.5 Given customers' allocations are fixed-like under the proposed TPM, these estimates for 2021/22 also give a reasonable indication of what they would be in 2023, subject to changes reflecting new investments and the application of the transitional cap on transmission charges, for example. As discussed in chapter 15, 1 April 2023 is currently proposed as the start date of any new TPM.

12.6 The indicative prices are illustrative only and subject to stakeholder feedback, Transpower's ongoing verification of underlying data sets, and the ongoing evolution of Transpower's customer and asset base.

12.7 Further, this consultation is not intended as a substitute for Transpower's consultation on prices for the 2023/24 pricing year, which would be based on any finalised TPM.

Indicative prices updated since Transpower's 30 June proposal[229]

12.8 The indicative prices that Transpower submitted as part of its 30 June proposal have been updated, to reflect the amendments to the proposed TPM following the

227 The proposed TPM must include indicative prices to allow the Authority and interested parties to understand its impact on designated transmission customers (clause 12.89 of the Code).

228 We consider that the advantages of using actual cost inputs and comparing indicative pricing with actual prices exceed the advantages of estimating indicative prices for 2023/24.

229 For supporting information, including spreadsheet models, see https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm/tpm-proposal-electricity-authority

Authority's review and referral-back of some aspects, and early technical feedback from stakeholders to Transpower.[230]

Differences between indicative prices and Authority 2020 estimates

12.9 Transpower's indicative prices differ from the Authority's estimates included in the 2020 Decision paper. We summarise key reasons for the differences in Appendix F.

Supporting information on indicative pricing

12.10 For stakeholders' reference, Table 2 summarises the information and available models developed by Transpower to illustrate the impact of the proposed TPM on prices.

Table 2 Supporting information to illustrate the impact of the proposed TPM

Information	Description
Reasons paper Appendix B: Indicative Prices	Summary results of indicative pricing modelling
Indicative Pricing Stakeholder Information	Indicative pricing information in spreadsheet format
Indicative Pricing Model	Calculates indicative charges for 2021/22
Covered Costs Model	Calculates annual cost of investments included in benefit-based charges for indicative pricing
Simple BBI customer and regional allocations	Includes simple method allocators for benefit-based charges in indicative pricing

Summary of indicative prices

12.11 The indicative pricing reflects the total maximum allowable revenue for transmission services ($798.8m in 2021/22). Table 3-Table 5 show the indicative prices under the proposed TPM by type of charge.

12.12 Indicative pricing modelling covers connection charges, benefit-based charges and residual charges, and the impact of the transitional price cap.[231] [232]

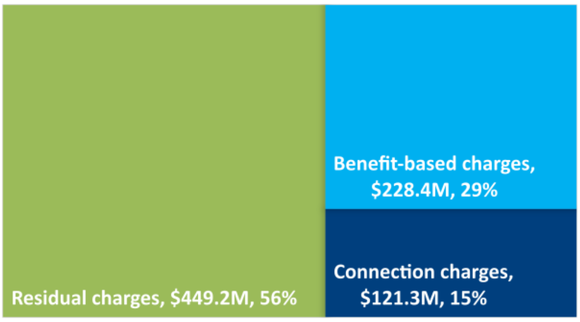
12.13 Figure 8 shows how Transpower's maximum allowable revenue for 2021/22 would be allocated between charges types under the proposed TPM.

230 These changes are summarised in KPMG, IPM amendments, Final report, September 2021, Appendix 1 Amendments to the Indicative Pricing, Model and its feeder models.

231 For further information refer to Appendix B: Indicative Prices, 15 September, section 3.

232 The indicative pricing assumes that the two existing prudent discount agreements (Waipori and Aniwhenua/Matahina) and existing notional embedding contract (BlackPoint) would not be carried over under the proposed TPM. See Transpower's *Reasons* paper, Appendix B: Indicative Prices, page B4.

Figure 8 Indicative charges by charge type in 2021/22



Source: Transpower TPM Reasons Paper Appendix B: indicative prices updated 15 September 2021

Table 3 Lines businesses: indicative prices by type of charge 2021/22, $m

Customer	BBC	Residual	Cap	Connection	Total
Alpine Energy	1.6	8.2	0.2	2.6	12.6
Aurora Energy	2.7	18.1	0.4	4.3	25.4
Buller Electricity	0.1	1.0	0.0	0.5	1.6
Centralines	0.4	1.1	0.0	0.8	2.2
Counties Power	3.5	6.7	0.2	1.0	11.3
EA Networks	1.0	9.2	0.2	0.3	10.7
Eastland Network	0.6	3.1	0.1	0.3	4.0
Electra	1.5	5.8	0.1	1.6	9.0
Horizon Energy Distribution Ltd	0.4	4.8	0.1	2.4	7.7
Mainpower NZ	1.6	7.5	0.2	2.9	12.1
Marlborough Lines	1.0	3.8	0.1	0.6	5.4
Nelson Electricity	0.1	0.7	0.0	0.1	0.9
Network Tasman	1.4	7.7	0.2	1.5	10.7
Network Waitaki	0.7	3.6	0.1	0.9	5.3
Northpower	6.5	9.0	0.3	2.5	18.3
Orion NZ	8.9	39.7	0.9	4.1	53.5
Powerco	10.9	53.2	1.1	16.0	81.3
Powernet	2.9	15.3	0.3	3.8	22.3
Scanpower	0.3	0.8	0.0	0.6	1.7
The Lines Company	0.7	3.9	0.1	1.4	6.1
Top Energy	1.2	3.6	0.1	1.0	5.9
Unison Networks	2.2	18.8	0.4	5.6	27.0
Vector	55.7	108.2	2.9	13.2	179.9
Waipa Networks	1.2	3.9	0.1	1.2	6.3
WEL Networks	2.7	15.3	0.3	1.7	20.0
Wellington Electricity Lines	7.6	29.8	0.7	8.2	46.3
Westpower	0.2	3.1	0.1	0.7	4.1
Total	**117.4**	**385.5**	**8.9**	**79.7**	**591.5**

Table 4 Generators: indicative prices by type of charge 2021/22, $m

Customer	BBC	Residual	Cap	Connection	Total
Contact Energy Ltd	23.8	1.4	0.4	4.2	29.8
Genesis Energy Ltd	8.7	0.7	0.1	5.0	14.5
MEL (Te Apiti) Ltd	0.2	0.0	0.0	0.1	0.3
MEL (West Wind) Ltd	0.4	0.1	0.0	0.1	0.6
Mercury NZ Ltd	6.7	1.8	0.1	3.5	12.1
Mercury SPV Ltd	0.4	0.1	0.0	0.1	0.6
Meridian Energy Ltd	47.8	1.4	0.9	16.6	66.6
Nga Awa Purua JV	1.7	0.3	0.0	0.4	2.5
Ngatamariki Geothermal Ltd	1.0	0.0	0.0	0.3	1.4
Nova Energy Ltd	0.1	0.4	0.0	0.3	0.7
Southdown Cogeneration Ltd	0.0	0.1	0.0	0.0	0.2
Southern Generation GP Ltd	0.0	-	-	0.2	0.2
Tararua Wind Power	0.2	0.1	0.0	0.1	0.3
Todd Generation Taranaki Ltd	0.8	0.1	0.0	0.1	1.0
Trustpower Ltd	1.1	0.0	0.0	0.8	2.0
Waverley Wind Farm	0.2	0.1	0.0	0.1	0.4
Total	**93.2**	**6.5**	**1.7**	**31.8**	**133.1**

Table 5 Direct connect: indicative prices by type of charge 2021/22, $m

Customer	BBC	Residual	Cap	Connection	Total
Beach Energy Resources NZ	0.2	0.5	0.0	0.1	0.7
Daiken Southland Ltd	0.2	0.5	0.0	0.2	0.8
GTL Energy New Zealand Ltd	0.0	0.0	-0.0	0.0	0.0
KiwiRail Holdings Ltd	0.3	2.2	-0.9	2.0	3.5
Methanex New Zealand Ltd	0.1	0.5	0.0	0.2	0.9
New Zealand Steel Ltd	2.7	8.8	-3.8	2.3	10.0
Norske Skog Tasman Ltd	0.5	6.4	-4.2	1.2	3.8
NZ Aluminium Smelters Ltd	12.4	30.3	0.8	1.3	44.7
OMV New Zealand Production Ltd	0.2	0.6	0.0	0.3	1.1
Pan Pac Forest Product Ltd	0.8	4.1	-1.7	1.0	4.2
Southpark Utilities Ltd	0.0	0.0	0.0	0.0	0.0
Whareroa Cogeneration Ltd	0.1	1.6	-0.9	0.2	0.9
Winstone Pulp International	0.5	1.9	0.0	1.1	3.5
Total	**17.8**	**57.2**	**-10.6**	**9.8**	**74.2**

12.14 Table 6-Table 8 show the indicative prices under the proposed TPM compared with prices under the current TPM for 2021/22.[233]

233 As discussed at footnote 232 the existing prudent discount agreements and notional embedding contract would not be carried over under the proposed TPM. The indicative prices under the proposed TPM therefore do not reflect any discounts. However, the charges under the current TPM for the relevant parties (Network Waitaki, Trustpower and Southern Generation) reflect these existing agreements.

Table 6 Lines businesses: indicative prices compared to actuals 2021/22

Customer	Current TPM ($m)	Proposed TPM ($m)	Change ($m)	Change(%)
Alpine Energy	12.3	12.6	0.3	2%
Aurora Energy	22.1	25.4	3.3	15%
Buller Electricity	0.6	1.6	1.1	197%
Centralines	2.7	2.2	-0.5	-17%
Counties Power	11.0	11.3	0.3	3%
EA Networks	4.6	10.7	6.1	134%
Eastland Network	5.5	4.0	-1.5	-27%
Electra	7.5	9.0	1.5	20%
Horizon Energy	3.5	7.7	4.2	120%
Mainpower NZ	12.3	12.1	-0.2	-2%
Marlborough Lines	6.7	5.4	-1.2	-18%
Nelson Electricity	1.0	0.9	-0.1	-10%
Network Tasman	11.8	10.7	-1.1	-9%
Network Waitaki	4.2	5.3	1.0	25%
Northpower	16.3	18.3	1.9	12%
Orion NZ	61.6	53.5	-8.1	-13%
Powerco	92.2	81.3	-10.9	-12%
Powernet	24.3	22.3	-2.0	-8%
Scanpower	1.9	1.7	-0.2	-11%
The Lines Company	4.7	6.1	1.3	28%
Top Energy	4.9	5.9	0.9	19%
Unison Networks	29.8	27.0	-2.9	-10%
Vector	172.1	179.9	7.8	5%
Waipa Networks	7.7	6.3	-1.4	-18%
WEL Networks	19.9	20.0	0.1	0%
Wellington Electricity	54.4	46.3	-8.1	-15%
Westpower	2.0	4.1	2.0	99%
Total	**597.7**	**591.5**	**-6.2**	**-1%**

Table 7 Generators: indicative prices compared to current actuals 2021/22

Customer	Current TPM ($m)	Proposed TPM ($m)	Change ($m)	Change (%)
Contact Energy Ltd	24.6	29.8	5.3	21%
Genesis Energy Ltd	10.3	14.5	4.3	42%
MEL (Te Apiti) Ltd	0.1	0.3	0.2	267%
MEL (West Wind) Ltd	0.1	0.6	0.5	439%
Mercury NZ Ltd	3.5	12.1	8.6	248%
Mercury SPV Ltd	0.1	0.6	0.5	616%
Meridian Energy Ltd	80.9	66.6	-14.3	-18%
Nga Awa Purua JV	0.4	2.5	2.0	478%
Ngatamariki Geothermal Ltd	0.3	1.4	1.1	428%
Nova Energy Ltd	0.3	0.7	0.4	157%
Southdown Cogeneration	0.1	0.2	0.1	143%
Southern Generation GP Ltd	0.2	0.2	0.0	-5%
Tararua Wind Power	0.1	0.3	0.3	413%
Todd Generation Taranaki	0.1	1.0	0.9	1407%
Trustpower Ltd	4.5	2.0	-2.5	-56%
Waverley Wind Farm	0.1	0.4	0.3	394%
Total	**125.5**	**133.1**	**7.7**	**6%**

Table 8 Direct connect: indicative prices compared to current actuals 2021/22

Customer	Current TPM ($m)	Proposed TPM ($m)	Change ($m)	Change (%)
Beach Energy Resources NZ	0.9	0.7	-0.2	-21%
Daiken Southland Ltd	0.8	0.8	0.1	7%
GTL Energy New Zealand	0.005	0.009	0.004	85%
KiwiRail Holdings Ltd	2.8	3.5	0.7	24%
Methanex New Zealand Ltd	0.7	0.9	0.1	15%
New Zealand Steel Ltd	3.1	10.0	6.8	219%
Norske Skog Tasman Ltd	1.2	3.8	2.7	228%
NZ Aluminium Smelters Ltd	58.3	44.7	-13.6	-23%
OMV NZ Production Ltd	1.2	1.1	-0.1	-12%
Pan Pac Forest Product Ltd	2.8	4.2	1.4	51%
Southpark Utilities Ltd	0.0	0.0	0.0	9%
Whareroa Cogeneration Ltd	0.2	0.9	0.7	428%
Winstone Pulp International	3.3	3.5	0.2	5%
Total	**75.5**	**74.2**	**-1.3**	**-2%**

Indicative prices by customer group

12.15 Table 9 summarises for each customer group the change in indicative prices compared with prices under the current TPM.

Table 9 Changes in prices under the proposed TPM by customer group 2021/22

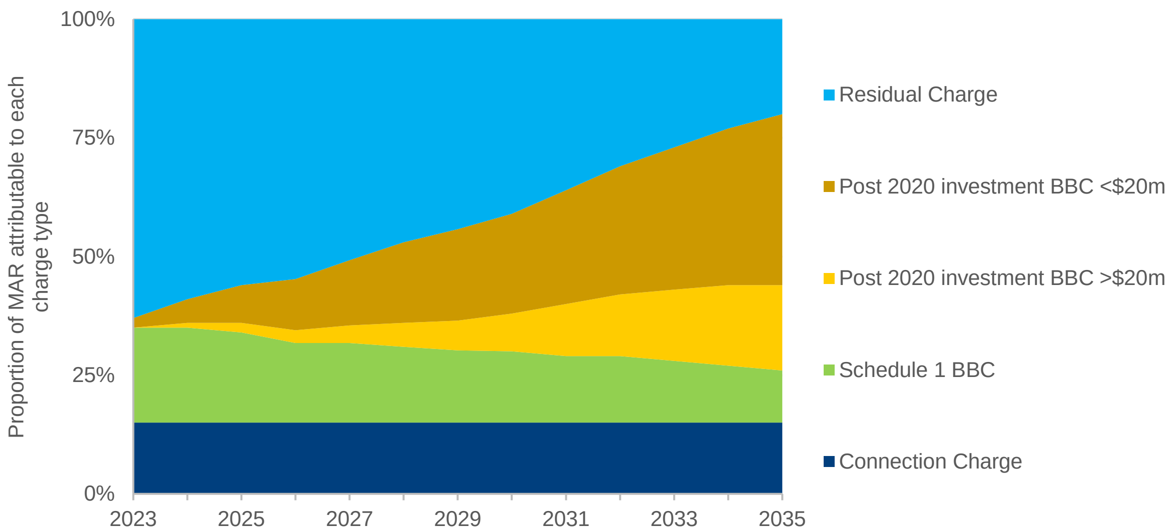
Generation	
North Island generation	The share of transmission charges increases from 2.5% to 4.6% under the proposed TPM, as North Island generators attract benefit-based charges. Currently, North Island generators pay the connection charge only and do not pay RCPD charges (except in their capacity as load customers) or HVDC charges.
South Island generation	The share of transmission charges reduces from 13.2% to 12.1% under the proposed TPM, as with benefit-based charges load customers and North Island generators would pay for a share of the HVDC. South Island generators' benefit-based charge would include a share of charges for North Island transmission investments. For example, the North Island Grid Upgrade improves South Island generators' access to North Island consumers.
Distributors	
Upper North Island distributors	The share of transmission charges increases from 25.6% to 27.0% under the proposed TPM, reflecting benefits from transmission investments that facilitate delivery of electricity from the South Island and lower North Island.
Lower North Island distributors	The share of transmission charges reduces from 28.8% to 26.5% under the proposed TPM. This is because this group of distributors is not a major beneficiary of the historical investments, (ie, Schedule 1 investments) that would make up the majority of benefit-based charges at the outset of any new TPM.

Upper South Island distributors	The share of transmission charges reduces from 12.6% to 12.4% under the proposed TPM.
Lower South Island distributors	The share of transmission charges increases from 7.9% to 8.2%. In part this reflects the extent of distributed generation connected to some of these distributors that lowers their exposure to the current RCPD charge.
Direct connect	
Direct connect	The share of transmission charges reduces from 9.4% to 9.3%. NZ Aluminium Smelters receives a significant reduction in charges, because it does not benefit significantly from the seven historical investments initially in the benefit-based charges. This reduction is almost fully offset by a combined increase for other direct connect industrials.

Possible evolution of indicative charges by type of charge out to 2035

12.16 Figure 9 illustrates the possible evolution of the different types of charges to 2035, based on Transpower's high-level projections of charges out to the 2034/35 pricing year.[234] [235]

Figure 9 Indicative charges by charge type from 2023 to 2035



Source: Transpower TPM Reasons Paper Appendix B: indicative prices updated 15 September 2021

12.17 At the outset, the share of revenue recovered from each customer group under the proposed TPM would be similar to the current TPM in 2021/22:

(a) 74.1% (down from 74.8%) for lines businesses

(b) 9.2% (down from 9.4%) for direct connect customers

(c) 16.7% (up from 15.7%) for generators.

234 See Appendix B of Transpower's *Reasons* paper for further detail on modelling of prices.

235 *Reasons* paper chapter 8 and Appendix B for assumptions and caveats.

12.18 Under the proposed TPM it is likely that in the longer term the share of overall charges paid by generators would increase, due to the projected:

(a) increasing share in revenue recovered through benefit-based charges, from about 20% in 2023 to over 60% in 2035

(b) decreasing share in revenue recovered through residual charges, from over 60% in 2023 to 20% in 2035.

12.19 The following factors (discussed in chapter 0) would influence the share of charges paid by load and generation customers under the proposed TPM:

(a) the outcomes from five yearly reviews of the proportion of charges paid by load and generation for low-value investments subject to the simple method

(b) the benefit-based allocations to load and generation, resulting from the application of the standard method to high value investments.

Projections of indicative prices by customer

12.20 Transpower considers it is not practicable to project indicative prices at a customer level, given a lack of granular forecast information and the extent of uncertainty over a longer timeframe. This includes uncertainty about where Transpower will invest, in what, and to the benefit of which of its customers – existing and new entrants.[236]

12.21 However, as part of consultation on prices under any new TPM and on an ongoing basis, Transpower would provide more granular pricing projections (covering 5-year regulatory control periods), which will promote certainty for customers.

Transitional cap on transmission charges

12.22 The proposed TPM includes a transitional cap on transmission charges that is consistent with the 2020 Guidelines. Chapter 12 of Transpower's Reasons paper explains the detailed application.

Relevant sections in the Guidelines and proposed TPM

Guidelines	Proposed TPM
Clauses 49 to 53	Part H: Clauses 113 to 115

12.23 The transitional cap is aimed at limiting electricity bill price shock that may be caused by implementing the proposed TPM. The Guidelines limit the total increase in interconnection charges relative to the charges a customer actually incurred in 2019/20, and this is reflected in the proposed TPM.

12.24 The transitional cap would limit the increase in customers' total electricity bill since 2019/20 due to the changes in transmission pricing to 3.5% plus inflation:

(a) for a distributor, the cap would be calculated based on the estimated total electricity bill (ex GST) of consumers in its network

236 *Reasons* paper, chapter 8 para 63, and Appendix B: Indicative Prices

(b) for direct connect load customers, the cap would also be based on an estimate of the customer's total electricity bill. From 2025, the cap would increase by 2 percentage points each year.

12.25 The Authority refers to these estimated total electricity bills as 'notional total electricity bills.'

12.26 The proposed TPM (and indicative pricing) reflects one year's worth of inflation adjustment since the 2019 pricing year (1.5%).[237] The Guidelines specify 2019 as the base year for the cap. To implement this, the cap uses the price index value for the year ending 31 March 2020 as the starting point for the CPI inflation. Consistent with the approach to covered cost (ie, actual cost from the period before the 'current' pricing year, ie, 31 March 2021), the cap for pricing year 2021/22 allows one year of inflation (as, relative to the base year, one additional year of costs is included).[238] The Authority considers this is consistent with the Guidelines and the statutory objective.

12.27 The transitional cap also takes into account changes in consumption. Figures reported here exclude any effects that changes in energy consumption might have on electricity bills, as such volume effects are not subject to the transitional cap.

Scope of the cap

12.28 The cap applies to charges for historical (pre-2019) investments included in the benefit-based charge, the residual charge, and any surcharge imposed by funding the cap.

12.29 The cap does not apply to connection charges, given the Guidelines in respect of the connection charge are essentially the same as the 2006 TPM Guidelines – see chapter 4.

12.30 Charges for any new benefit-based transmission investment will not be subject to the cap. The transitional cap relates to managing bill shock risks from redistributing existing charges, much of which would now be recovered through the residual charge. That rationale does not apply to investments after 2019/20, because customers would have opportunities to scrutinise new investments and would be charged broadly in proportion to private net benefits.

Recovery of charges not recovered from "capped customers"

12.31 To ensure Transpower can recover its maximum allowable revenue, transmission revenue 'lost' due to a customer's charges being capped is recovered by a surcharge on other customers' charges. This surcharge is proportional to the total of the benefit-based charge and the residual charge, consistent with the Guidelines.[239]

237 The proposed TPM calculates annual covered cost with reference to capital costs (depreciation and opening RAB) for the preceding financial year. This reduces the administrative burden and cost and removes the need for annual wash-ups. For example, indicative prices for pricing year 2021/22) uses an opening RAB for 1 July 2019 and includes capital cost additions for the period ending on 30 June 2020.

238 The CPI index increases from 1,041.75. to 1,057.5, or 1.51%.

239 Where payment of a surcharge would result in a load customer exceeding its cap, a further adjustment (to the surcharge) will ensure that this does not happen.

The cap only applies to load customers

12.32 In accordance with the 2020 TPM Guidelines, the proposed transitional cap on transmission charges applies to the extent that a customer is a load customer, that is, a direct connect or distribution customer. The cap does not apply to a customer in its capacity as a generator (although they nonetheless contribute to the cap).[240] In its 2020 Decision the Authority reasoned that the cap should be limited to load because under any new TPM generators' charges would be benefit-based and exempt from residual charges (except to the extent they have load).

12.33 The proposed TPM clarifies that generators will not be subject to the cap, even though generators may consume electricity (eg for starting up) and could also have embedded load. This approach is a departure from the Guidelines, which provide for a cap on charges for each existing load customer (being a designated transmission customer whose equipment draws electricity from the grid or from any generation behind it).

12.34 Transpower considers that the transitional cap should not apply to a generator who is occasionally a direct consumer, as the cap is not designed for that: in practice the cap would be very low relative to the transmission charges being capped, resulting in significant wealth transfers.[241]

12.35 However, the transitional cap may apply to a customer with 'intermingled' load and generation. In these situations customers are treated as grid-connected load with embedded generation.[242] The proposed TPM allows Transpower to determine the status of such a customer (clause 5(3)).[243] For example, Whareroa Cogeneration is treated as a direct supplied load customer, and on that basis the transitional cap applies to this customer.

12.36 The Authority considers this departure from the Guidelines is justified under clause 2, and we agree with Transpower that, otherwise, the effect of the application of the cap could compromise competitive neutrality with respect to distributed generation.[244]

Changes to sources for gross energy information

12.37 The proposed TPM also departs from the Guidelines in respect of the data Transpower would use in the calculation of the cap on transmission charges:[245]

(a) The Guidelines require gross energy data to be sourced from the reconciliation manager (clauses 50(a) and 50(b)).

(b) The proposed TPM would use distributor disclosure information because it is more readily available and unlikely to be materially different.

12.38 The Authority considers that this departure from the Guidelines is justified under clause 2, as it is consistent with the intent of the Guidelines, including the practical

240 See Authority's 2020 Decision paper, p.84, para 13.22.

241 Reasons paper, page 12.7, para 16

242 *Reasons* paper, page 12.8

243 The proposed TPM also distinguishes a category of grid-connected generators with embedded load (where the generation and load is not 'intermingled'). These will be treated as 'supplying load customers' (note that there are no current examples of such customers). See paragraph 7.9.

244 *Reasons* paper, page 12.9

245 Refer Transpower's *Reasons* paper, Page A.5, Appendix A: List of clause 2 Departures.

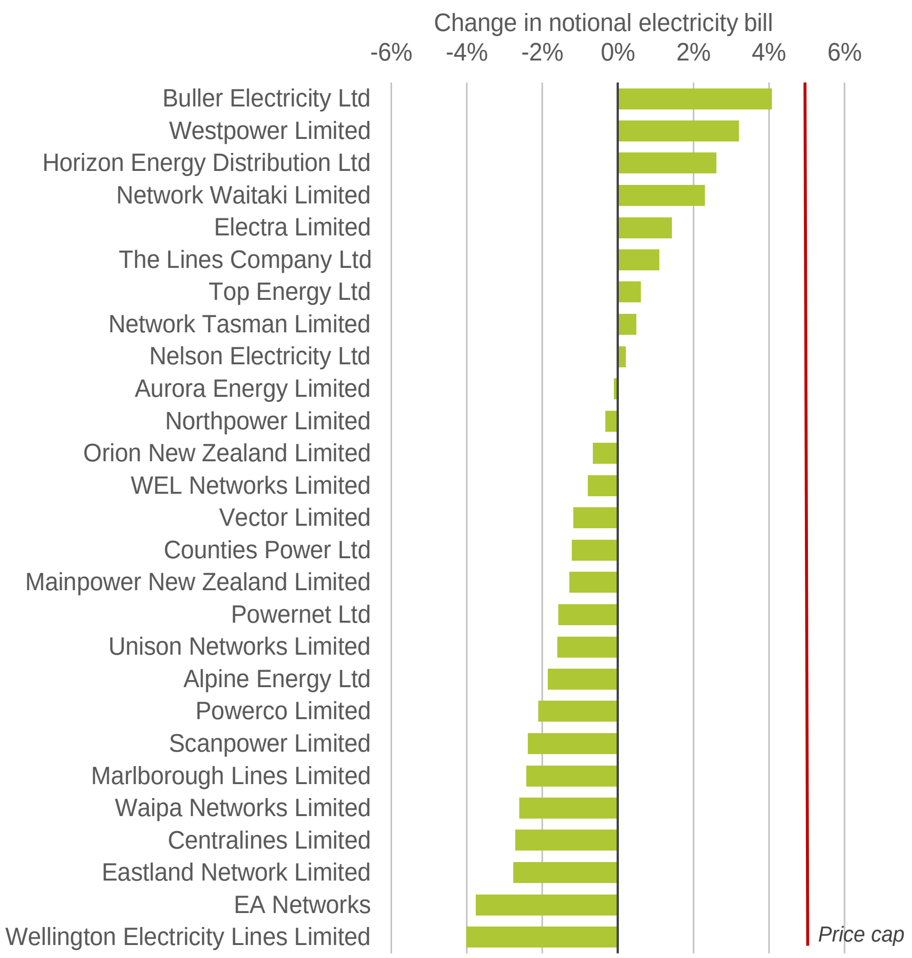
considerations of clause 1(b), and consistent with its statutory objective as likely administrative efficiencies would promote the efficient operation of the electricity industry.

Impact of transitional cap

12.39 At the outset, the transitional cap limits the increases in customers' notional electricity bills (caused by the implementation of any new TPM), relative to bills in 2019/20, to 3.5% plus inflation. For the 2021/22 pricing year, that limits any increases to 5% (3.5% plus 1.5% inflation as measured by the CPI).[246]

12.40 Figure 10 shows the change in notional electricity bills for consumers connected to distributors' networks since 2019/20 to the start of 2021/22. As all increases are below 5%, no distributor exceeds the cap that applies in the indicative pricing.

Figure 10 Distributors: change in notional total electricity bills 2019 to 2021

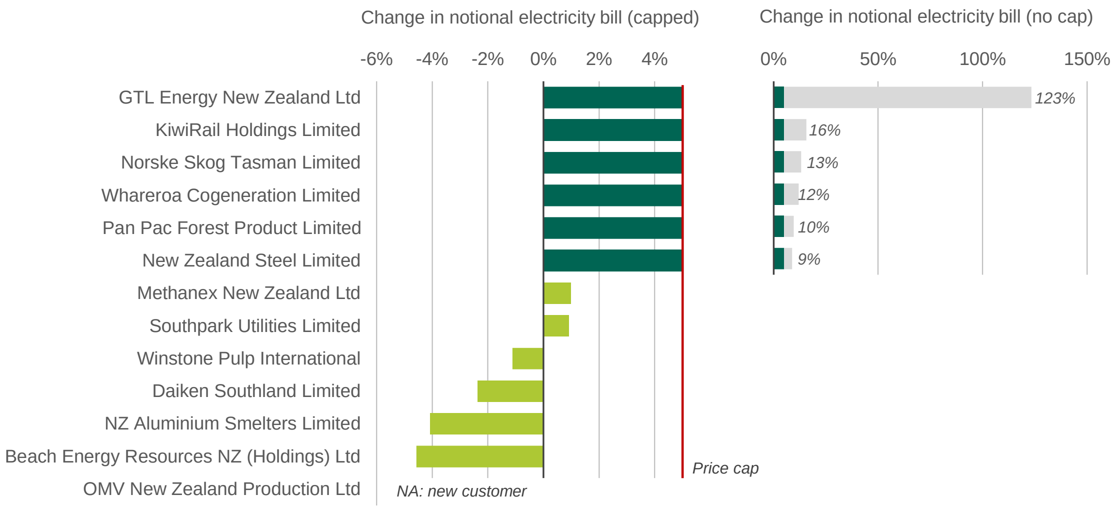


Note: Networks with volatile transmission charges year to year (eg, EA Networks) may experience a reduction in notional electricity bills 2019 to 2021, but an increase in charges in 2021/22 due to the proposed TPM compared to actual charges in that year. This is discussed further below.

246 Implementation of any new TPM from 1 April 2023 would imply increases in electricity bills due to implementation of a new TPM would be limited to 3.5% + 5.25%=8.75% relative to electricity bills in 2019/20. See assumed CPI in TPM Indicative Pricing Model published by Transpower.

12.41 Figure 11 shows the change in notional electricity bills since 2019/20 due to the proposed TPM for direct-connect customers. The dark green bars show charges would be capped for six direct-connect customers. Without the cap, they would face materially larger increases in notional electricity bills (grey bars, right-hand chart).[247]

Figure 11 Direct connects: change in notional total electricity bills 2019 to 2021



12.42 Table 10 shows the cap's impact on indicative prices for those six direct-connect customers.[248]

Table 10 Impact of transitional cap on direct-connects' indicative prices, $m[249]

Customer	Indicative prices: before cap	Indicative prices	Change due to cap
Norske Skog Tasman Limited	8.0	3.8	-52%
GTL Energy New Zealand Ltd	0.02	0.01	-55%
KiwiRail Holdings Limited	4.4	3.5	-19%
New Zealand Steel Limited	13.8	10.0	-28%
Pan Pac Forest Product Limited	5.9	4.2	-28%
Whareroa Cogeneration Limited	1.82	0.88	-52%

Impact of transitional cap on indicative prices

12.43 Table 3 - Table 5 above indicated the impact of the cap for each customer. As noted above, customers not subject to the cap will fund the cap through a surcharge, except to the extent that funding the cap would mean a customer's own cap is exceeded.

247 Note the difference in scale.

248 See footnote 246.

249 The indicative pricing shows what each customer's charges would be if the proposed TPM applied in 2021/22. Any new transmission pricing is expected to come into effect on 1 April 2023 (although there are still several steps remaining in the process which could impact on this). Any new charges applying in 2023 would be different to the indicative charges released for a number of reasons, including needing to take account of any new transmission investments, any new customers, and any customers that have shut down their operations (such as Norske Skog's Tasman Mill).

Impact on typical household bills

12.44 To illustrate the impact of the proposed TPM on households, the Authority estimated expected changes in the electricity bills of the typical household served by each distributor.[250]

Overall household bills may decrease slightly

12.45 Compared to current actual transmission charges, the average New Zealand household could have expected a small reduction in their typical electricity bill of $2.80 (0.1%) if the proposed TPM had applied this pricing year. This assumes changes in transmission prices are passed through in full to consumers.[251]

The impact on household bills varies across regions

12.46 Impacts would vary across New Zealand. Some households' bills would increase, and some would decrease. The impact across the country is illustrated in Figure 12, which shows the estimated change in a typical household bill in each distribution network, if the proposed TPM applied in 2021/22.[252]

12.47 The impact in 2021/22 ranges from an annual decrease of $40 for a typical household in Eastland Network's region to a $165 increase for a typical household served by Buller Electricity. For context, MBIE estimates that the New Zealand average household has an annual household electricity bill of about $2,121.

12.48 At the top end, the change in Buller Electricity's charges includes a proposed asset reclassification (see below) so in this sense is not strictly comparable to the other impacts. And for all four distributors at the top of the range, volatile transmission charges make an assessment of the impact of the proposed TPM on household electricity bills very sensitive to the year of comparison. On a like for like basis, the transmission charges for Electricity Ashburton, Horizon and Westpower are lower than indicated in the 2020 Decision paper.

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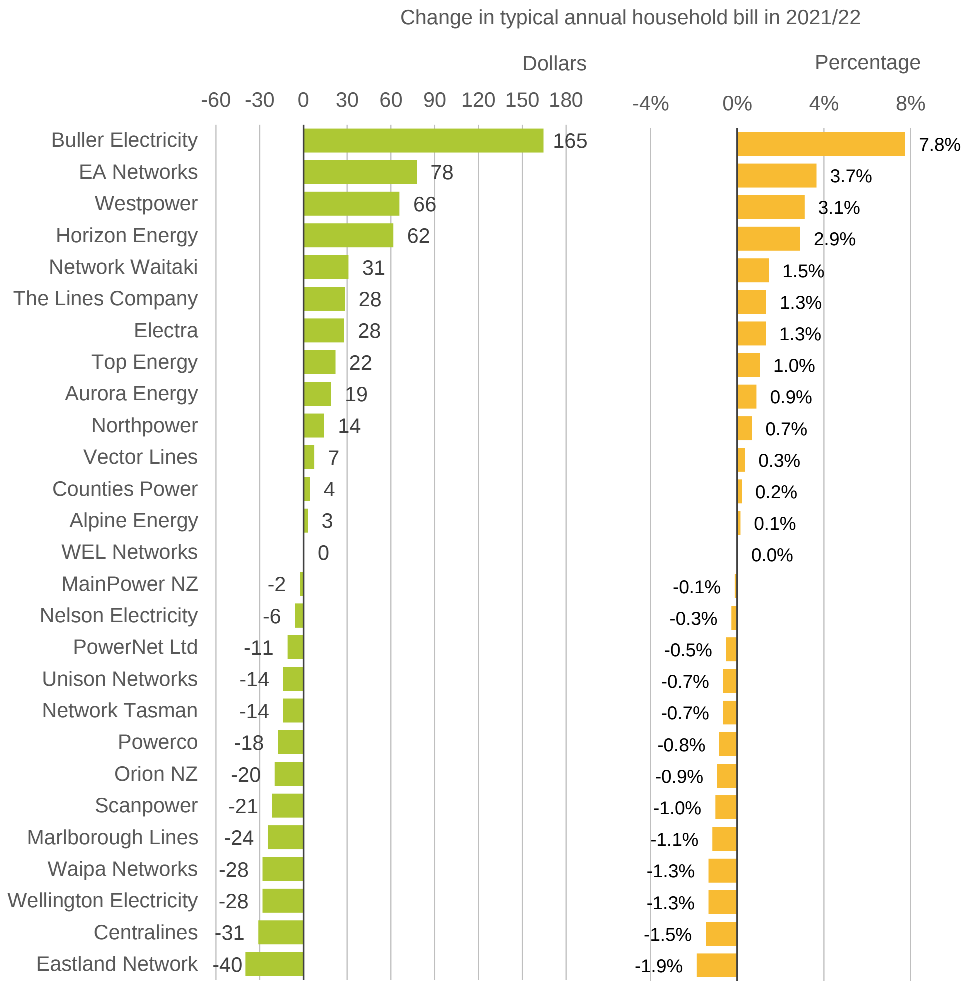
250 We estimate the changes in charges in $/kWh terms for the typical household, and then compare that to a typical household's total electricity bill. Our estimate relies on MBIE's modelling of the national average household (based on total national electricity sales, and total national household consumption). For 2021, the average household consumed 7,223kWh of electricity per annum, at a cost of $0.29/kWh, with an average bill of $2,121 per annum (7,223 x 0.29), GST inclusive, or $1,844 GST exclusive. Source: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/energy-prices/electricity-cost-and-price-monitoring/.

251 Pass-through of transmission charges from a distributor to customers (in general, retailers) depends on the distributors' pricing approach. The Authority's modelling assumes retailers will translate changes in transmission charges into $ changes per unit of energy and pass charges on to their customers accordingly. This assumes workable competition in the residential, commercial, and industrial electricity retail markets.

252 Indicative pricing information at distribution company level may conceal variations in pricing impacts by location.

Figure 12 Impact on annual household bills by distribution network (2021/22)



Effect of volatile transmission charges

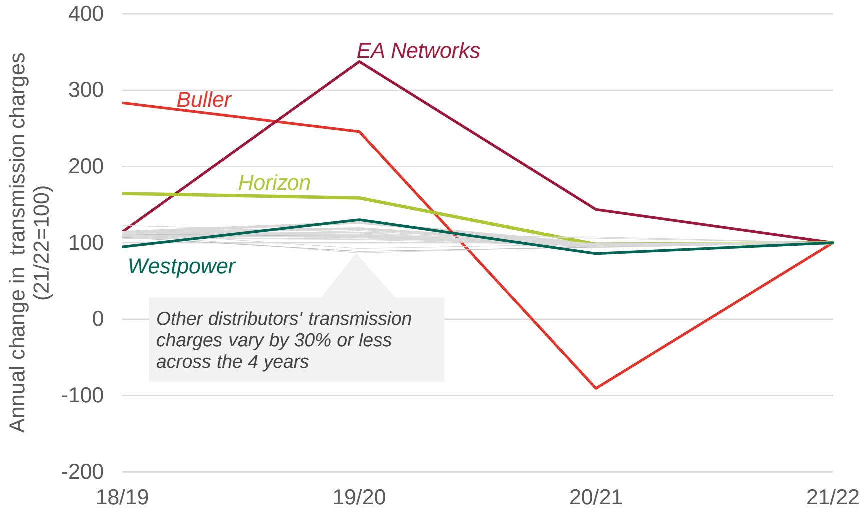
12.49 Figure 13 shows trends in distributors' transmission charges between 2018/19 and 2021/22. Revenue is normalised to the distributors' 2021/22 charges to avoid simply highlighting the differences in the amount of charges paid by the different distributors.[253]

12.50 For most distributors, year-on-year movements in transmission charges is typically less than 30%. For these distributors, the trends in charges are shown in grey. By contrast, Buller Electricity, EA Networks, Horizon and Westpower Distributors experienced significant year-on-year changes in recent years. [254]

253 Distributors' transmission charges in 2021/22 range from $0.55m (Buller Electricity) to $171m (Vector).

254 For example, EA Network's charges in 2021/22 were $4.5m and the years before $6.5m, $15.4m and $5.2m. Buller's charges in 2021/22 were $0.55m and the years before -$0.48m, $1.35m and $1.56m (note: Transpower's information disclosures show a $0.98m payment of connection charges from Transpower to Buller in pricing year 2020/21 so that overall charges for that year were negative).

Figure 13 Trends in transmission charges paid by distributors (2021/22=100)



Source: Transpower information disclosures (schedule F6) and Authority calculations.

12.51 Figure 14 illustrates the effect of volatility in transmission charges by comparing the estimated average household electricity bill impact of the proposed TPM (in 2021/22) to 2021/22 actual bills (green dots, and as also shown on the left in Figure 12).

12.52 For consumers in most networks the impact of changes in transmission charges on average households' electricity bills is much less affected by volatility in transmission charges across years. The dots in the chart are closely together.

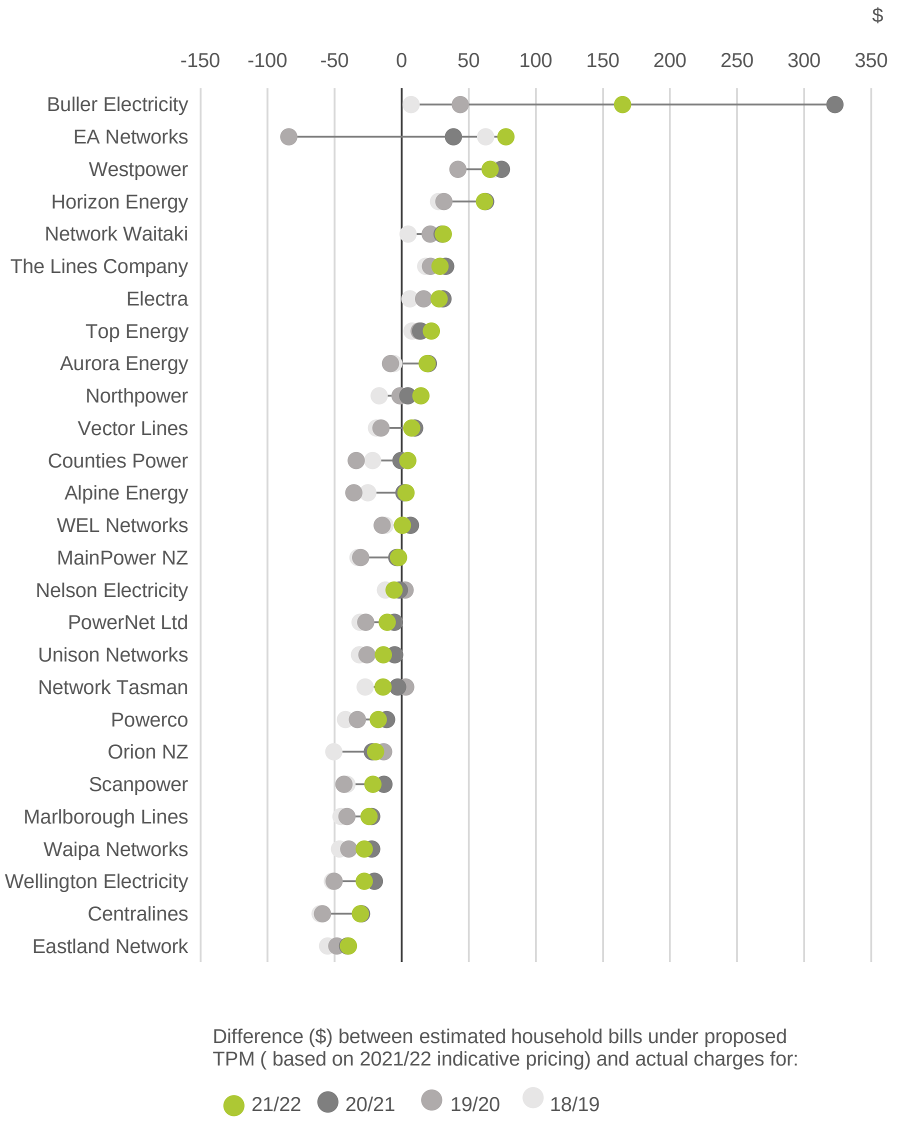
Notable differences driven by individual customer circumstances

12.53 For networks with volatile transmission charges, a single year comparison of the impact on electricity household bills is not necessarily representative.

12.54 Buller's increases in transmission charges and estimated household electricity bills under the proposed TPM in 2021/22 prices are driven in part by Transpower's proposed reclassification of an asset from an interconnection to connection asset. The reclassification would increase Buller's transmission charges because the cost of these assets would be paid by Buller rather than being shared with other customers (through the residual charge).

12.55 In addition, Buller's transmission charges vary significantly year-on-year under the current TPM. Buller's transmission charges in 2019/20 (and hence the notional electricity bill used to determine the transitional price cap) were high compared to subsequent years and therefore the transitional price cap does not apply to Buller (see Figure 10).

Figure 14 Change in typical household electricity bills under proposed TPM (2021/22) compared with actual estimated bills



Note: All in dollars of the day (not adjusted for inflation).

Source: Authority calculations based on TPM indicative pricing and Transpower information disclosures (schedule F6)

12.56 EA Networks' highly volatile transmission charges mean that the proposed TPM would increase average household electricity bills in 2021/22 compared to current bills. But compared to electricity bills in 2019/20 (used to determine the transitional price cap) household electricity bills would now be lower under the proposed TPM (and hence the transitional price cap does not apply to EA Networks – see Figure 10).

12.57 The same year-to-year volatility in transmission charges affects Horizon and Westpower when comparing the impact on charges under the proposed TPM with actual transmission charges in 2021/22 or 2019/20.

12.58 The Authority requests that stakeholders in their submissions highlight any potential data inaccuracies, potential alternative data sources or, if relevant, alternative judgements on how inputs are applied in the indicative pricing which they consider should be made, explaining the advantages of the alternative input or approach.[255] Where an approach would require a change to the proposed TPM, please explain what clause in the proposed TPM would need to be modified, how the clause should be modified, what the change would achieve and why that change would better meet the Guidelines and promote the statutory purpose.

Household bill impacts do not reflect potential reductions in ACOT payments

12.59 The Authority notes that these estimated household bill impacts do not take account of potential reductions in ACOT payments by distributors.[256] The removal of the RCPD charge in the proposed TPM, and its replacement by fixed-like benefit-based and residual charges, could reduce residential electricity bills by a significant proportion by removing the aggregate amount of ACOT payments (up to approximately $33 million in the current year according to current information disclosures and pricing methodologies).

12.60 Of the distributors whose customers face an estimated annual bill impact of more than $25, Westpower, Horizon Energy, and The Lines Company and, we understand, Electra are all currently making significant ACOT payments.

Consultation questions

Do you have any comments on indicative pricing or the application of the transitional cap?

255 In its 2020 Decision paper on the Guidelines, the Authority noted that it had made some adjustments to indicative charges to reflect information received from parties on the input data or the calculation of their indicative charges. (See 2020 Decision paper, Appendix A, from paragraph A.56.) The 2021/22 indicative charges are based on the proposed TPM that has been developed since 2020, so adjustments made in 2020 are not necessarily relevant here.

256 See the Authority's 2020 Decision paper, chapter 16, p102.

13 Other provisions of the proposed TPM

13.1 Part A of the proposed TPM contains the preliminary clauses covering general definitions, and general topics such as the calculation of charges, and consultation and information requirements.

13.2 The clauses seek to improve on the drafting of the current TPM (see Transpower's Reasons paper, p3.5 para 13), as well as address specific parts of the Guidelines.

13.3 In this chapter we focus on the proposed provisions related to consultation on transmission charges, the information to be provided on the basis of transmission charges, the treatment of transmission alternatives in charges, and the adjusting of customer data under exceptional operating circumstances. However, the Authority is interested in stakeholder feedback on any aspects of these preliminary provisions.

Relevant sections in the Guidelines and proposed TPM

Guidelines	Proposed TPM
Clause 5, 6, 9	Part A: Clauses 1-18

Consultation on transmission charges

13.4 Clause 17 of the proposed TPM specifies which interested parties Transpower must at a minimum consult with before transmission charges or adjustments are finalised.

13.5 Where appropriate, the minimum obligation focuses on those with a material financial interest, and where the set of interested parties is less predictable Transpower is required to consult with the public.

13.6 Transpower also notes that consultation requirements may sometimes be fulfilled as part of other consultation.

13.7 The Authority considers these consultation requirements provide sufficient opportunities for participants to engage on key matters and are consistent with the Guidelines.

Information about transmission charges

13.8 Clause 18 of the proposed TPM requires Transpower to provide each customer with sufficient information to enable them to understand the basis for their charges.

13.9 For load customers this must include otherwise unallocated operating costs and reassignment amounts in the residual revenue.

13.10 As noted in Transpower's Reasons paper, the proposed TPM does not specify the detail or the presentation of this information. The reason is that this information is yet to be developed and that this is best left out of the proposed TPM as the content can be expected to evolve over the years in line with customer feedback.

13.11 Provision of information about charges promotes the efficient operation of the electricity industry by enabling customers to scrutinise the basis of charges, including through transparency on the make-up of residual charges.

13.12 The Authority considers that the clause in the proposed TPM is consistent with the Guidelines and with its statutory objective.

Treatment of transmission alternatives

13.13 The proposed TPM assigns the cost of transmission alternatives to the relevant connection or interconnection investments.

13.14 The operating costs of transmission alternatives in connection investments are shared between customers at the relevant connection locations in proportion to their total connection charges.

13.15 The costs of any transmission alternatives are directly attributed to the relevant BBI.

13.16 Where the transmission alternative is an alternative for both connection and interconnection assets, Transpower may apportion the operating costs between these asset types.

13.17 The proposed approach mirrors the approach in the current TPM and is consistent with the Guidelines. The proposed treatment of the cost of transmission alternatives promotes the efficient operation of the electricity industry by allowing participants and Transpower to consider the most efficient solution without such choices being distorted by differential funding.

Exceptional operating circumstances

13.18 The proposed TPM contains, at clause 15, a provision that allows Transpower to adjust a customer's allocation data in case of an 'exceptional operating circumstance' in the power system, if it considers this may have distorted the allocation data.

13.19 Allocation data is defined as 'any data, including metering information, about a customer's supply, demand, injection, offtake or gross energy that affects the customer's allocation of transmission charges.'

13.20 The current TPM contains such a clause which has been applied 52 times since 2010. Transpower considers the provision may be more relevant in future as allocators are relatively fixed and thus anomalous power system conditions could become locked in, which could distort the intended incentives of the TPM.

13.21 The proposed TPM does not define what would be classed as an exceptional operating circumstance. However, as it relates to distorting allocators such events would need to be large enough to materially distort the residual charge (which adjusts on the basis of a lagged four-year average) or the allocators under the simple method (which are proposed to be revised every five years). As such, while such a clause may be more relevant as a 'safety valve' in future, it is unclear that it would be used more frequently or would result in charges becoming less fixed-like.

13.22 While the Guidelines do not explicitly address exceptional operating circumstances, the Authority considers the provision is not inconsistent with the Guidelines and that including clause 15 is likely to better promote its statutory objective by avoiding materially distorted charges.

Other preliminary provisions

13.23 Section A of the proposed TPM covers a range of other topics and general definitions to support the interpretation and operation of the proposed TPM. The Authority considers that these are consistent with the Guidelines (to the extent they have not been addressed specifically in this or other chapters).

13.24 The Authority invites stakeholders' views on whether the preliminary provisions are appropriate or whether they can be improved.

Consultation questions

Do you have any comment on or suggestions for the preliminary provisions cl1-18?

14 Regulatory statement

14.1 This chapter confirms that the requirements for a regulatory statement in accordance with section 39(2) of the Electricity Industry Act 2010 has been met.

Statement of objectives of the proposed amendment

14.2 The objective of the proposed amendment is to put in place a transmission pricing methodology that promotes the Authority's statutory objective. Specifically, and for the reasons set out in the Authority's previous papers, the Authority considers that any new TPM should:

(a) provide transmission customers with efficient signals of the cost of connecting to and using the transmission grid, and therefore promotes:

(i) efficient use of the grid

(ii) efficient investment in the grid and transmission alternatives

(iii) efficient investment in new generation, promoting competition in the wholesale electricity market

(b) otherwise recover the cost of the interconnected grid in a manner that least distorts transmission customers' decision-making (and is therefore least likely to result in the industry operating inefficiently)

(c) promote competition, by providing a level playing field for generators regardless of location and between new and existing generators by equalising the basis for charging

(d) maintain appropriate levels of network reliability, through efficient signalling of congestion and the cost of grid investments

(e) be durable.

14.3 In implementing any new transmission pricing methodology, the Authority would also seek to limit the exposure of load customers to a price shock in their electricity bill as a result of introducing any new TPM.

14.4 Such a TPM would address the problems with the current TPM as summarised in Chapter 2 with reference to the 2019 Issues paper and 2020 Decision paper.

14.5 The proposed TPM would give effect to the above through:

(a) relying on wholesale electricity market nodal prices to signal the immediate cost of using the grid (with the Guidelines also enabling Transpower to implement a targeted transitional congestion charge via an operational review, if needed to assist it to efficiently manage ongoing congestion in specific circuits), thus addressing any risks of congestion as needed, while otherwise avoiding sending distortionary signals

(b) charging the costs of grid investments to those who benefit from them in the form of a fixed-like benefit-based charge or connection charge, thus sending efficient signals as to the cost of connecting to, and using, the grid

(c) using a fixed-like residual charge to recover any revenue not gathered through other transmission charges

(d) allowing for transmission charges to be discounted if otherwise they would exceed a customer's standalone costs or make it viable for that customer to inefficiently bypass the grid

(e) providing for a transitional cap to avoid any price shocks.

14.6 The proposed amendment would incorporate the new TPM (Appendix C) into the Code.

Evaluation of the costs and benefits of the proposal

14.7 The Authority expects the proposed TPM will deliver significant benefits to consumers. The Authority has previously set out (including in its 2019 Issues Paper and 2020 Decision Paper) its qualitative and quantitative analysis as to why a TPM with the above features is likely to better meet its statutory objective, and the costs and benefits of such an approach. Preceding sections in this paper provide additional, primarily qualitative, analysis of the costs and benefits associated with particular aspects of the proposed TPM as drafted.

14.8 The Authority has therefore assessed the costs and the benefits of the proposed TPM and considers that the proposal's benefits outweigh its costs. It considers that the proposal is superior to continuing with the current TPM.

14.9 The Authority has further produced an estimate of the quantifiable net benefits the proposed TPM could deliver New Zealand consumers. It estimates that, in the central scenario, these benefits would have an average present value of +$1.25b over 28 years, with a range of $0.4b-$2.9b (and potentially materially higher depending on evidence around the weighting factor under the simple method). This cost benefit analysis is set out in Appendix D.

14.10 The quantified cost benefit analysis evaluates the proposed TPM against the status quo and provides estimates of the benefits and costs associated with alternative approaches or design options for aspects of the proposed TPM, focusing on design options with the potential to have material impacts on net benefits as indicated by the qualitative analysis. These options include variations in generators' share of benefit-based charges under the simple method, and whether overhead operating cost are included in benefit-based charges or recovered through residual charges.

14.11 The consideration of options and trade-offs for more detailed aspects of the proposed TPM are discussed in the relevant sections in this document. Given their nature, these are primarily qualitative assessments of the benefits and costs of detailed options.

14.12 The quantified CBA estimates exclude unquantified benefits, which are significant. Unquantified benefits include those from: removing incentives for mass-market consumers to invest in technologies to avoid transmission charges; avoided costs of inefficient undergrounding; reductions in unpredictable transmission charge volatility; and durability (which would be undermined if consumers in some regions would have to pay for new investments made for their benefit and continue to pay for major investments they did not benefit from).

14.13 While the quantified net benefits are substantial, the quantified CBA remains one of a number of factors the Authority considered in approving this proposed TPM for consultation, alongside its qualitative assessments.

Evaluation of alternative means of achieving the objectives

Proposal is preferred to alternative means of implementing the Guidelines, subject to consultation

14.14 A range of options have been considered for each of the components of the proposed TPM, first by Transpower and then the Authority, with material choices set out in this paper for feedback.

14.15 Options have been assessed in terms of their consistency with the Guidelines and the Authority's statutory objective, as documented in each chapter. The Authority considers the proposed TPM is consistent with the Guidelines and the statutory objective. However, it has also identified possible amendments to the proposed TPM that may better promote competition, reliability and the efficient operation of the electricity industry. The Authority welcomes feedback on these options.

14.16 Additional discussion of options and their relative merits is available in Transpower's Reasons paper and the position papers Transpower published for feedback during its development process.

Decision on Guidelines considered alternative means of resolving the problems identified

14.17 The evaluation of alternatives in this consultation paper is focused on options for each of the components of the proposed TPM within the framework of the Guidelines.

14.18 For the avoidance of doubt, higher level alternatives to the Authority's Guidelines were considered during earlier phases of the TPM review. Specifically, the Guidelines themselves resulted from consideration of a wide range of alternatives to resolve the problems identified with the current TPM over the course of the TPM review (over some ten years), and a quantitative CBA of a short list of options. See Chapters 2 and 15 and Appendix B of the 2020 Decision paper, and Appendix E of the 2019 Issues paper.

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

14.19 The Authority's objective under section 15 of the Act is to promote competition in, reliable supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers.

14.20 Section 32(1) of the Act says the Code may contain provisions consistent with the Authority's objective and necessary or desirable to promote any or all of the following.

Table 11 Summary of how proposal complies with section 32(1) of the Act

Component		Summary
(a)	competition in the electricity industry	The proposed TPM would support competition in the electricity industry, because it would: • put generation across the country on an even footing with transmission charges that reflect expected net positive private benefits • put transmission investments and transmission alternatives on an even footing • remove any first mover disadvantage issues affecting new investment and competition in electricity generation[257]
(b)	the reliable supply of electricity to consumers	The proposed TPM has tailored methodologies for allocating the cost of future reliability and resiliency investments, making it more likely that these investments would reflect the quality that consumers want (are willing to pay for) System reliability would not be compromised by the removal of the current RCPD charge. The proposed TPM relies on wholesale market nodal prices to manage congestion risks. Transpower has concluded that existing system operator and grid owner tools can effectively and efficiently manage risk in a way that limits load shedding and ensures the grid is secure.
(c)	the efficient operation of the electricity industry	The proposed TPM, through the removal of the RCPD and HVDC charge, and implementing fixed like BBC and residual charges would improve the signals of the cost of using the grid, promoting efficient use of and investment in the grid, and efficient investment in generation. Other features, such as an expanded prudent discount policy, further assist with avoiding inefficient investments. The proposed TPM has addressed the trade-offs between the benefits of accuracy and practical considerations, striking an appropriate balance on transaction and compliance costs. A quantitative CBA indicates that the net efficiency gains are positive and of a material order of magnitude.
(d)	the performance by the Authority of its functions	The proposal does not impact the performance by the Authority of its functions.
(e)	any other matters specifically referred to in this Act as a matter for inclusion in the Code.	Nil.[258]

257 Further, so that the proposed TPM promotes competition in the electricity industry, its design avoids, to the extent possible, uneven treatment of incumbent and new entrant transmission customers. Where design choices presented trade-offs, the Authority has favoured in the proposal arrangements that avoid creating barriers to entry. Similarly, it has favoured options that are be technology-neutral, ensuring the TPM avoids creating unequal treatment of, for example, battery storage and intermittent generation with high capital and low operating cost.

258 No other matters specifically referred to in the Act are relevant here, but the Authority notes for completeness that that the Authority is considering proposing additional amendments to the Code related to the proposed TPM. See para 2.18.

Authority has had regard to the Code amendment principles

14.21 When considering amendments to the Code, the Authority is required by its Consultation Charter to have regard to the Code amendment principles summarised in Table 12, to the extent that the Authority considers they are applicable.

Table 12 Regard for Code amendment principles

Principles	Comment
1. Lawful	The proposal is lawful because it is consistent with the Authority's statutory objective, and the relevant provisions in the Electricity Industry Act 2010 (including those on amending Code), and Part 12 of the Code (in particular subpart 4 on the development of a transmission pricing methodology.) The Authority considers that the provisions in the proposed TPM are consistent with the TPM Guidelines and its statutory objective. Where proposed provisions depart from the details of the Guidelines the Authority considers these departures are justified because they ensure the proposed TPM would better meet the Authority's objective and therefore comply with clause 2 of the Guidelines. Those instances are clearly identified and discussed in this document for stakeholders' feedback.
2. Clearly identified efficiency gain or addresses market or regulatory failure	The proposal addresses clearly identified problems with the current transmission pricing methodology that hinder competition in the electricity industry and create efficiency costs. These failures have been set out in detail in the Authority's 2019 Issues paper and 2020 Decision paper. By addressing these problems, the proposed TPM would deliver clearly identified efficiency gains, as discussed at paras 14.2-14.5, striking a balance between the benefits of precision and practical considerations in administering and complying with the TPM (for example in the design of the simple method to allocation, or in how operating costs are assigned to benefit-based charges).
3. Net benefits are quantified	The net benefits of the proposal have been identified and the size and order of magnitude of those net benefits (within ranges that have robustly tested the inherent uncertainties in assumptions) have given the Authority confidence that the proposal is for the long-term benefit of consumers.
Tie-breakers	Code amendment principles 4-9 are tie-breakers, to be used in case the assessment of costs and benefits is inconclusive about the best option. The assessment provided is unambiguous, and there is thus no purpose in considering the tie-breaker principles any further.[259]

259 Nonetheless, while some principles (small-scale trials) fall away because the overall assessment of the proposed amendment show benefits exceed costs, some of the tie-breaker principles, (eg, greater competition and flexibility for innovation) are relevant to the Authority's consideration of subsidiary options.

Wider factors

Proposed TPM supports a transition to a low-emissions economy

14.22 The Authority considers that the proposed TPM would better position New Zealand for a transition to a low-emissions economy by ensuring the best use of existing and future infrastructure.

14.23 It would do this by reducing the cost of consuming electricity at times when consumers value it the most and improve the signals of the cost of using the grid. Improved pricing would support the right investments being made at the right time and in the right places, including by incentivising customers to scrutinise investments and to become involved in the grid upgrade process.

14.24 The proposed TPM results in net benefits, in context of rapid demand growth over the next 25 years and increasing penetration of renewables. In its assessment the Authority also assumes no new investments in thermal installations and the decommissioning of Huntly Rankine gas/coal units, consistent with the Climate Change Commission's demonstration pathway and the Government's 100% renewable target.[260]

14.25 The increasing reliance on renewables, including to meet peak demand, continues a well-established trend in New Zealand. For example, hydro generation met 63% of demand at the 100 highest peaks in 2019, having grown over time.

14.26 An increase in demand at peak need not translate to higher emissions. Renewables have a cost advantage over fossil fuel generation and this cost advantage is assumed to grow, with significant cost reductions in wind generation over time. Renewables operate at lower cost than gas or other fossil fuels, particularly with emissions pricing increasing and so will logically be used to serve increased demand before gas peaking is turned on, including when combined with battery storage.

14.27 The proposed TPM – by replacing the HVDC and RCPD charges with benefit-based charges – would put all generation on an even footing, regardless of type or location. Currently, South Island generation pays all of the HVDC charges, although North Island generators also benefit from the link as do consumers. Under the proposed TPM, North Island generators would also pay benefit-based charges for interconnection investments, in broad proportion to benefits.

14.28 The proposed TPM would remove incentives to operate mobile diesel generators to offset network load at suspected peak times to avoid RCPD charges (examples of which had been provided to the Authority during its consultation on the Guidelines). Operating such diesel generators, when there is significant spare capacity in the local and regional transmission network, unnecessarily increases emissions and costs.

14.29 The proposed TPM would result in more efficient transmission prices, so generators, industrials and other consumers can factor transmission costs correctly into their decisions. This ensures transmission pricing does not interfere with emissions pricing and plays its part in the transition to a low-emissions economy at lowest cost to consumers.

260 https://www.climatecommission.govt.nz/our-work/advice-to-government-topic/inaia-tonu-nei-a-low-emissions-future-for-aotearoa/modelling/

Consistency with government's wellbeing & living standards objectives

14.30 The Authority considers that over the long term the proposed TPM would reduce, on average, typical household electricity bills in New Zealand. In locations where typical household electricity bills would rise, those increases are modest. They would be smaller still when potential reductions in Avoided Cost of Transmission payments by distributors are taken into account. The CBA also indicates that the proposed TPM would be for the long-term benefit of consumers.

14.31 The Authority has prepared a simple and high-level descriptive distributional analysis to examine correlations between impact on consumers – in terms of the initial household electricity bill impact, and changes in long-term consumer welfare – and two demographic measures (the proportion of an area's population who identify as Māori,[261] and the NZ deprivation index[262]) - for each distribution network's area.

14.32 Figure 15 below shows that there are no particular patterns between initial household electricity bill impacts and the proportion of people identifying as Māori in an area, or an area's average deprivation.

14.33 In terms of long-term consumer welfare impacts, residential consumers in all network areas would on average experience material improvements of between 3.3 and 6.8%. The average welfare improvement in percentage terms is nevertheless lower in areas with a higher proportion of people identifying as Māori and areas with a higher average deprivation. The correlation is moderate.

14.34 The Authority notes also that the proposed TPM provides for a price cap such that each transmission customer's total transmission charges cannot rise by more than 3.5% of its total 2019/20 electricity bill (taking account of inflation and load growth), as detailed in chapter 12. Under the current indicative pricing there are no distributors for whom the cap would apply (as price increases are lower than a 3.5% increase plus 1.5% inflation).

14.35 The Authority acknowledges energy hardship is a challenge for a group of New Zealanders.[263] MBIE is the lead policy agency on energy hardship policy development and is running a wide programme of work on this matter including the Support for Energy Education in Communities (SEEC) $17million funding programme aiming to lift people out of energy hardship.[264]

14.36 The Authority's remit includes the Consumer care Guidelines, which guide retailers in terms of how they engage with all consumers, how retailers ensure domestic consumers maximise their potential to access and afford a constant and suitable electricity supply; and how retailers help domestic consumers minimise harm caused by insufficient access to electricity or by payment difficulties.[265] The Authority also

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261 Using Statistics New Zealand's census response data

262 Otago University's NZ Deprivation Index

263 More than 100,000 households were spending more than 10 per cent of their income on power in 2017, Electricity Pricing Review (2019), p 18

264 Information on MBIE's Energy hardship work programme is available here: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-hardship/, including SEEC information here: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-hardship/support-for-energy-education-in-communities-programme/

265 Refreshed Consumer care guidelines (replacing the medically dependent consumer guidelines and vulnerable consumer guidelines) took effect from July 2021. For more information see

communicated with retailers regarding their duty of care for customers during and after recent Covid-19-related lockdowns.[266]

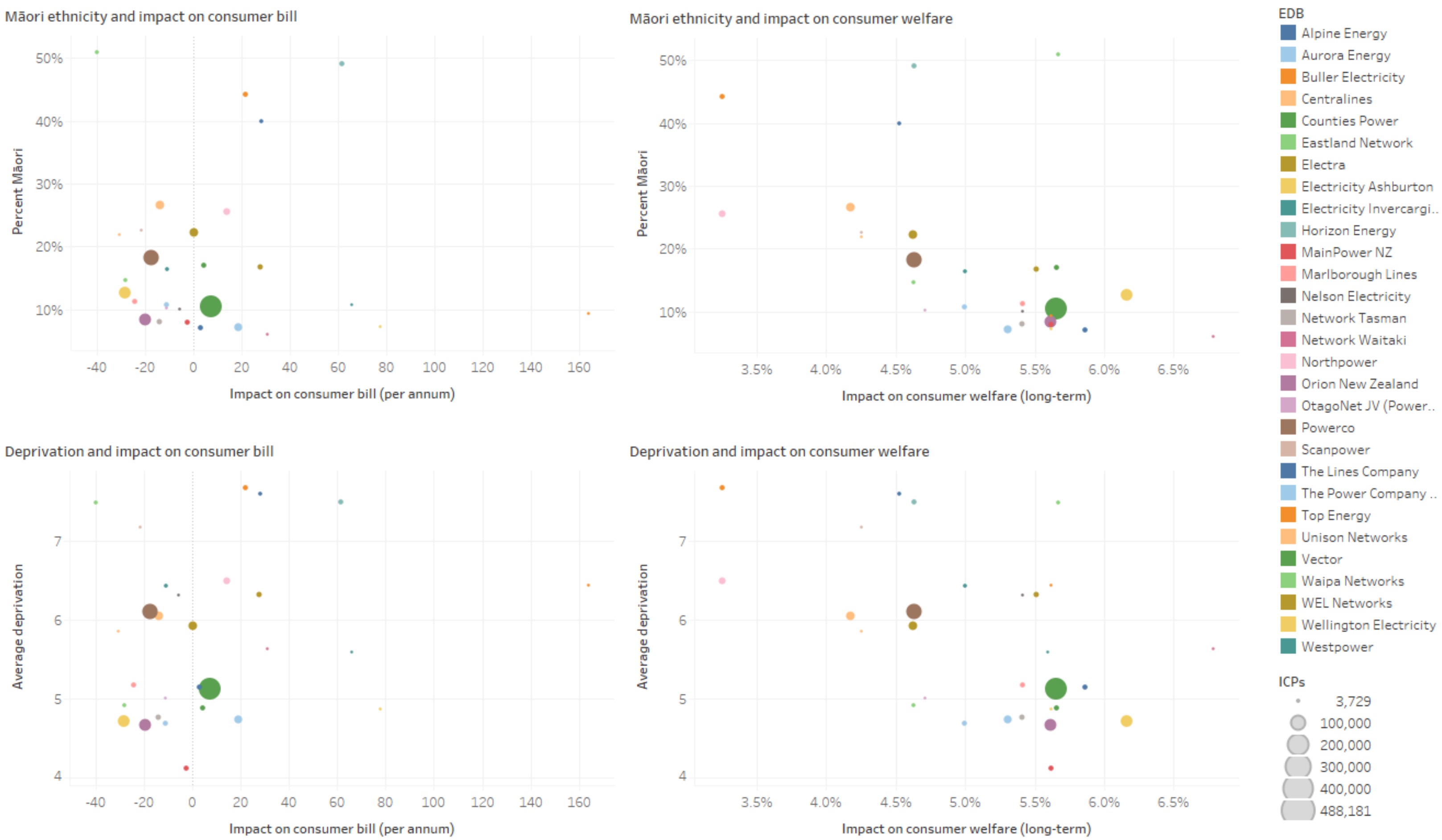
Consultation questions

Do you have any comments on the regulatory statement or the assessment of wider factors?

https://www.ea.govt.nz/development/work-programme/operational-efficiencies/medically-dependent-consumer-and-vulnerable-consumer-guidelines/

266 https://www.ea.govt.nz/about-us/media-and-publications/covid-19/information-for-industry/

Figure 15 Initial household electricity bill impacts and longer term consumer welfare impacts of the proposed TPM



Note 1: 'Impact on consumer bill' is the indicative change in the average residential electricity bill in the initial year of the proposed TPM, GST inclusive (see chapter 12).

Note 2: 'Impact on residential consumer welfare' has been estimated for a 28 year period (see CBA, in Appendix D)

Note 3: The correlation coefficients (r-values) are: top-left: 0.06, top-right 0.54, bottom-left: 0.06, bottom-right 0.50

Sources: Proportion of Census respondents identifying as Māori, NZ Census,. New Zealand Deprivation Index: Otago University Department of Public Health, 2013

15 Next steps and proposed commencement date

Authority to make a decision on incorporating TPM into Code

15.1 This consultation marks the next stage in the development of a new TPM, consistent with the Guidelines that the Authority published in June 2020.

15.2 The Authority is looking forward to receiving submissions on the proposed TPM. Details on the submission process and timeframes are set out in Appendix A. Appendix B brings together all of the consultation questions set out in this document.

15.3 After consideration of submissions, the Authority will consider whether to incorporate the proposed TPM into the Code. This may entail amendments of the proposed TPM as a result of the Authority's consideration of submissions.[267] If the Authority decides to include the proposed TPM in the Code, it must also determine, after consultation with Transpower, the date on which the TPM must take effect.[268]

15.4 The Authority expects to make its decision by 31 March 2022, subject to consideration of submissions, which could impact on content and the timing of the Authority's decision.

Transpower next steps

15.5 If the Authority decides to incorporate a new TPM into the Code, Transpower would then calculate new transmission prices based on the new TPM and engage with stakeholders before these are finalised. After carrying out its own internal assurance processes Transpower must publish transmission prices consistent with any new TPM.[269] The Authority expects that Transpower would publish any new transmission prices in the first week of December 2022.

Commencement date

15.6 The Authority envisages that 1 April 2023, the start of the following pricing year, would be the commencement date for any new TPM. This is the date that new transmission prices under any new TPM would take effect. Transpower may only charge for transmission services in accordance with the approved TPM.

15.7 The Authority's expectations as to the timing of the stages following publication of this consultation paper are illustrated in the following figure. The proposed commencement date is consistent with the Authority's expectations signalled in its 2020 Decision paper on the Guidelines.[270]

15.8 The following figure is consistent with a similar figure included in the 2020 Decision paper. The red arrow indicates the current position in that timeline, since Transpower submitted its 30 June Reasons paper.

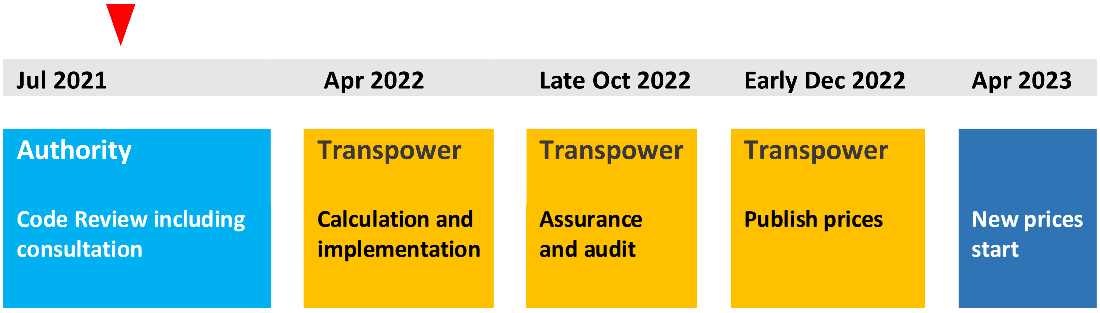
[267] Clause 12.93.

[268] Clauses 12.93 and 12.94.

[269] Clause 12.96.

[270] 2020 Decision paper, paragraph 17.31.

Figure 16 Timeline towards commencement of proposed TPM



15.9 The Authority considers that the estimated timings set out in the figure above allow enough time for the intervening tasks (calculation and implementation, assurance and audit, publication) to be completed to an acceptable standard. However, we are interested in stakeholders' views on this matter.

15.10 The Authority must consult with Transpower before it decides on a commencement date.[271] While we have discussed this matter with Transpower, we have not yet formally consulted with Transpower. This is something the Authority would envisage doing after receiving submissions.

Transitional arrangements for BBC standard method allocation

15.11 The proposed TPM includes transitional arrangements for the BBC standard method allocation. As the benefit-based charge provisions of any new TPM would apply to grid investments commissioned after 23 July 2019, there are a number of larger investments (valued at over $20m) which have already been approved for which costs must be allocated using the standard method in the annual pricing round commencing July 2022. Transpower would need to produce updated modelling, consult with its stakeholders,[272] and determine final allocations for at least two such projects by 31 August 2022.[273] However, assuming the Authority decides on a new TPM by 31 March 2022, this may not allow sufficient time to complete all of these steps – noting these would be the first BBCs determined using the standard method.

15.12 For these reasons, a provision is included in the proposed TPM allowing Transpower discretion to delay for one pricing year the start of the standard method allocation in such circumstances. If Transpower decides to apply such a delay, investment costs would instead be allocated on a temporary basis (for the first year) using the simple method for BBC allocation.[274] Once the standard method allocation for these projects is completed (likely in the following year), the costs would be reallocated, on a retroactive basis, using a wash-up. This would occur for investments commissioned after 23 July 2019, (ie, post-2019 investments) and before 1 July 2022. A similar discretion would apply for investments commissioned between 1 July 2022 and 30

271 Clause 12.94.

272 Consultation with stakeholders on cost allocation for high-value investments (which are allocated via the standard method) is required by clause 5(b) of the Guidelines and clause 17 of the proposed TPM.

273 Transpower expects two such high-value "intervening BBIs" to be commissioned before 1 July 2022 - the post-2019 CUWLP investment and the reconductoring of the Otara-Flat Bush section of the OTA-WKM A and B lines.

274 See subclauses 43(3) and (4) in the proposed TPM.

June 2023 (for similar reasons). These proposals would be a departure (under clause 2 of the Guidelines) from the requirements of clause 20(a) of the Guidelines.

15.13 These transitional arrangements will facilitate an April 2023 commencement for any new TPM (bringing forward benefits for consumers). BBCs will be set according to a benefit-based method in the interim (albeit a simple method) and charges will ultimately be set according to the standard method (with a wash-up), which will ensure the BBC achieves the correct incentives for benefiting customers, promoting the efficient operation limb of the Authority's statutory objective. The Authority considers these transitional arrangements to be consistent with its statutory objective, and meet the requirements for a departure from the details of the Guidelines under clause 2, for these reasons and the reasons set out in Transpower's submission of 15 September.[275]

Next steps and timing on related code amendment proposals

15.14 The Authority expects to consult on proposed Code amendments on the following four TPM-related subjects, with indicative timing for consultation as follows:[276]

(a) Beginning in the 4th quarter 2021 (and likely running into 1st quarter 2022): the method for allocating residual loss and constraint excess (LCE), which is currently based on the existing TPM.

(b) 1st quarter 2022: the availability of data on activity behind the GXP to better support the effective working of any new TPM (in particular, the allocation of the residual charge).

(c) 2nd quarter 2022: the avoided cost of transmission (ACOT) provisions in Part 6 of the Code, which in practice are linked closely to existing transmission charges.

(d) 3rd quarter 2022: provision for future reviews to ensure the implementation of the TPM remains workable and continues to promote the Authority's statutory objective.

Consultation questions

Do you agree that 1 April 2023 is an appropriate commencement date for the proposed TPM?

Do you agree with the proposed transitional measure for any standard method investments for which allocation is not completed?

275 See Transpower, 15 September refer-back part 2 response submission, section 5.1, paras 40 – 53.

276 This is not necessarily a closed list. Eg, there might also need to be changes to the benchmark transmission agreement to make it compatible with the new TPM (the Authority has not thoroughly considered this yet) and a Code amendment to make corresponding changes to existing transmission agreements.

Appendix A How to make a submission

A.1 The Authority's preference is to receive submissions in electronic format (Microsoft Word). Submissions in electronic form should be emailed to TPM@ea.govt.nz with 'Consultation Paper— Proposed Transmission Pricing Methodology' in the subject line.

A.2 If you cannot send your submission electronically, please contact the Authority at TPM@ea.govt.nz to discuss alternative arrangements.

A.3 Please note the Authority wants to publish all submissions it receives. If you consider that the Authority should not publish any part of your submission, please:

(e) indicate which part should not be published

(f) explain why you consider that part should not be published

(g) provide a version of your submission that can be published (if the Authority agrees not to publish your full submission).

A.4 If you indicate there is part of your submission that should not be published, we will discuss with you before deciding whether to not publish that part of your submission.

A.5 However, please note that all submissions received, including any parts that are not published, can be requested under the Official Information Act 1982. This means the Authority would be required to release material that was not published unless good reason existed under the Official Information Act to withhold it. The Authority would normally consult with you before releasing any material that you said should not be published.

A.6 Please deliver your submissions by **5pm** on **Thursday 2 December 2021**

A.7 This deadline allows eight weeks for submissions, rather than the Authority's typical six-week consultation period.

A.8 There will be an opportunity for stakeholders to make cross-submissions. Cross-submissions are due by 5pm on Thursday 23 December.

A.9 The Authority will acknowledge receipt of all submissions electronically. Please contact the Authority at TPM@ea.govt.nz if you do not receive electronic acknowledgement of your submission within two business days.

Appendix B Questions to assist submitters

B.1 You are welcome to comment on any matter relevant to the Authority's proposal.

B.2 We have posed questions throughout the consultation paper and appendices to help prompt responses to specific aspects of the proposal. These are repeated here.

B.3 Please do not feel you need to limit your responses to the consultation questions or that you need to answer all of them. Please explain your answers in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.

The Authority welcomes feedback on any aspect of the proposals set out in this document, and comment, analysis and evidence on alternatives that would be consistent with the Guidelines and may better meet the Authority's statutory objective. Without limiting the scope of feedback that we are seeking, we have set out some specific questions below.

Chapter 2 A new TPM

Do you have any comments on the content of this chapter?

Response

Chapter 3 Grid asset classification

Do you agree with the proposed approach to treat connection assets as interconnection assets for a limited time if the assets will ultimately be interconnection assets when fully commissioned?

Do you agree with the proposed reclassification power? Should there be any further conditions on Transpower's use of this discretion?

Do you have any other feedback on Grid Asset Classification in the proposed TPM?

Response

Chapter 4 Connection charges

Do you agree that the proposed TPM should specify that connection asset replacement values be regularly updated to promote cost-reflective charges and certainty?

Do you have any comment on the proposed approaches to address first mover disadvantage issues, including on:

- the proposed FAC mechanism for Type 1 FMD
- the alternative option of an upper limit on application of the benefit-based approach for Type 2 FMD
- the approach to applying 'above-limit costs' under this alternative option?

Do you have any other feedback on the proposed TPM in relation to connection charges?

Response

Chapter 5 Benefit-based charges: allocation

Do you have any comment on the proposed standard and simple benefit-based allocation methods?

Do you have any comment or additional evidence on the proposed weighting of benefits between load and generation customers under the simple method, or with respect to the proposed review of the allocation?

Response

Chapter 6 Benefit-based charges: covered costs

Do you have any comment on the proposed approach to covered costs, including on:

- whether overhead opex should be recovered through the BBC or residual charge, and any evidence to support your view?
- the recovery of opex on fully depreciated assets through the residual charge?

Response

Chapter 7 Residual charges

Do you have any comment on how the proposed TPM implements the residual charge provided for in the Guidelines?

Do you agree with the application of the residual charge to generation with embedded load, or can you suggest a better way to mitigate charge avoidance incentives and risk of an uneven playing field?

Do you have any comment on the proposed approach to application of the residual charge to battery storage to avoid double-counting of load?

Response

Chapter 8 Adjustments

Do you agree with or have any other feedback on the proposed provisions for adjusting transmission charges?

The Authority welcomes feedback on any aspect discussed or proposed in this chapter, including whether:

- the proposed TPM should provide more detail on the method for determining new entrants' benefits
- the charges for a new entrant should be the same as an equivalent incumbent each year (as in the proposed TPM), on a whole-of-life basis as in the Guidelines
- the proposed thresholds for 'large' and 'substantial sustained' change in grid use are appropriate
- the connection of a distributor to a new (and additional) GXP and the upgrading of a transformer at a distributor's GXP should be adjustment events
- the plant disconnection provision should be extended to plant de-rating
- the relevant provision should be further extended to cover a substantial sustained decrease in grid use not related to a plant disconnection or de-rating
- the residual charge for a new entrant and an expanding customer should adjust with a lag and a gradual ramp-up, as proposed
- the proposed 'related entity' provisions deal appropriately with avoidance concerns, and whether there is a case for a broader or more general 'related entity' provision to deal with other, potentially unforeseen, avoidance opportunities?

Response

Chapter 9 Prudent discounts

Do you have any comments on the proposed PDP provisions? The Authority welcomes comment on any aspect of the proposal, including whether:

- Transpower should have to prepare a PD practice manual, and if so when, and should it be binding on Transpower
- 15 years should be the default maximum period with a longer term possible on proof
- prudent discounts should be funded via the residual charge and as appropriate the benefit-based charge
- customers should be able to terminate a prudent discount agreement before the end date of the agreement?

Response

Chapter 10 Transitional congestion charge

Do you have any feedback on the proposal not to include a TCC in the proposed TPM, for the reason that widespread risk of congestion from removing the RCPD charge is unlikely and that, if necessary, the grid owner and system operator have effective tools to manage the power system quickly and efficiently?

If not, how should a TCC be designed to be consistent with the Guidelines? Under what situations should it be applied and how should its size and allocation be determined?

Response

Chapter 11 kvar charge

Do you have any comment on the proposal not to include a kVAr charge in the proposed TPM?

Response

Chapter 12 Indicative prices

Do you have any comments on indicative pricing or the application of the transitional cap?

Response

Chapter 13 Other provisions of the proposed TPM

Do you have any comment on or suggestions for the preliminary provisions cl1-18?

Response

Chapter 14 Regulatory statement

Do you have any comments on the regulatory statement, or the assessment of wider factors?

Response

Chapter 15 Next steps

	Do you agree that 1 April 2023 is an appropriate commencement date for the proposed TPM? Do you agree with the proposed transitional measure for any standard method investments for which allocation is not completed?
Response	
Appendix: Proposed TPM	
	Do you have any feedback that would improve the drafting of the proposed TPM?
Response	
Appendix: Cost benefit analysis	
	Do you have any comment on the cost benefit analysis?
Response	
Other	Is there anything else in relation to the proposed Code amendment that you wish to comment on? Do you have any other feedback on any other aspect of the proposed TPM?
Response	

Appendix C Proposed TPM

Consultation questions

Do you have any feedback that would improve the drafting of the proposed TPM?

Appendix D Cost-benefit analysis

Material net benefits

D.1 For the reasons set out above (and in the Authority's previous papers), the Authority considers that the proposed TPM is superior to the status quo. Its quantitative CBA analysis further indicates that the proposed TPM would result in material net benefits as compared with the status quo.

D.2 The central scenario's net benefits have an average present value of +$1.25 billion over 28 years with a range of $0.4b-$2.9b.[277]

D.3 Table 13 presents the summary results from the CBA, as well as alternative scenarios that reflect variations on the proposal. The results are based on averages across a range of modelling results with varying assumptions (see sensitivity analysis).

Table 13 Summary of cost benefit analysis results

$2018 million in present values. Probability-weighted averages, in lower and upper quartiles

Weighted mean $m	Central	Tiwai open	Simple method to 75:25 at review	Overhead opex in RC
Gross change in consumer welfare	2,303	2,545	3,009	2,521
Less transfers (lower interconnection costs)	-1,205	-1,144	-810	-1,131
Net change in consumer welfare	1,098	1,401	2,199	1,391
Less inefficient battery investment	55	48	55	55
More efficient investment, scrutiny, certainty	179	179	179	179
Transmission benefits brought forward	243	154	242	247
Transmission cost brought forward	-281	-159	-257	-256
Other costs	-42	-42	-42	-42
Net benefit	**$1,253 ($365 - $2,918)**	**$1,580 ($685 - $3,228)**	**$2,377 ($713 - $3,465)**	**$1,574 ($447 - $2,901)**

D.4 Key aspects of the different scenarios are as follows:

(a) **Central** – broadly 50:50 (47:53) percent sharing of benefit-based charges between generators and load under the simple method, overhead opex recovered through benefit-based charges, Tiwai closes in 2024 and the Rankine units at Huntly are decommissioned in 2024.

(b) **Tiwai stays open** – Tiwai stays open, Huntly Rankine units are decommissioned in 2026, but otherwise the same settings as the central scenario.

277 This may increase, eg to $2.4b if simple method allocators between load and generation changes to, say 75:25 based on evidence from standard method assessments at review. See Chapter 5.

(c) **Simple method 75:25** – five year review leads to a change to a 75:25 percent allocation of benefit-based charges between load and generators under the simple method, but otherwise the same settings as the central scenario.[278]

(d) **BBCs exclude overhead opex** – overhead opex is recovered through the residual charge, but otherwise the same settings as the central scenario.

Key results and sources of quantified costs and benefits

D.5 This section provides a brief discussion of the key results presented in Table 13 above, before providing detail on the underlying assumptions and further analysis.

D.6 The proposed TPM is expected to result in a net benefit to consumers of $1,253 million within a range of $365 - $2,918 million under the central scenario.

D.7 Within this, the net change in consumer welfare from more efficient grid use, excluding reductions in interconnection charges, is expected to be $1,098 million.

D.8 This benefit comes from increased consumption of electricity and lower prices when consuming higher amounts of electricity, as a result of replacing the RCPD and HVDC charges with benefit-based and residual charges. This reflects:

(a) a reduction in the incremental cost of using electricity, with most transmission revenue recovered from fixed charges

(b) a significant reduction in prices during peak demand periods when consumers value electricity the most.

D.9 The impact of the proposed TPM on wholesale electricity prices (inclusive of interconnection charges) and demand is shown in Figure 17, for scenarios where the Tiwai aluminium smelter (NZAS) closes and scenarios when it does not close. For illustration, results are shown as arithmetic averages across the range of scenarios for demand growth, generation costs and potential future allocations of interconnection charges as between load and generation customers encapsulated in Table 13.

D.10 Figure 17 shows noticeable differences in average prices and demand with and without NZAS closing in 2024 – around the time that NZAS closes and also longer term.

D.11 Under the proposed TPM, reflecting in particular the proposed simple method to allocating benefits, consumers would also pay less transmission charges ($1,205 million, present value), with generation customers paying higher shares of interconnection revenue.

D.12 This reduction in consumers' interconnection charges is a direct gain to consumers; however, it is a transfer and thus not something the Authority takes into account directly.[279] Instead, the Authority is looking to assess the effects of the proposed

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278 The Authority has also modelled an alternative option with a 75:25 percent sharing of benefit-based charges between load and generators under the simple method from the outset (and no change at review), but otherwise the same settings as the central scenario. Net benefits in this scenario are $2,433m within a range of $965m-$3,704m).

279 The Authority does consider transfers where they have implications for efficiency. The proposed TPM is expected to improve gross consumer welfare by $2,303 million relative to the status quo between 2022 and 2049. This equates to 3.3% of baseline market expenditure at a present value of $70 billion.

TPM on competition in, reliable supply by and efficient operation of the electricity industry, as improvements in those will benefit consumers in the long term.

D.13 While electricity generators pay higher interconnection charges, they are expected to benefit from the proposed TPM, because it results in increased expenditure on electricity.[280]

D.14 The removal of the RCPD charge removes incentives for inefficient investment in utility-scale batteries to avoid transmission charges and shift transmission costs to other grid users. This is an efficiency gain valued at $55 million. Efficient investment in batteries and other distributed energy resources is of course likely to continue.

D.15 An increase in peak demand would bring forward transmission investment relative to the baseline – a cost of $281 million. As transmission investment costs are brought forward so too are the benefits from that transmission investment (reduced congestion, improved reliability). Those benefits (specifically those not already captured in the grid use model) are valued at $243 million based on reductions in congestion and losses, and exclude additional benefits from improved reliability which have not been evaluated in this CBA.[281]

D.16 The proposed TPM is also expected to result in benefits of $179 million from more efficient investment decisions. There are three components to this.

(a) $117 million net benefit from generators or consumers being incentivised to not make an investment/consumption decision in a region that would necessitate transmission investment. This benefit arises because, unlike under the current TPM, generation and load would face the transmission-related costs of their decisions (as they would pay for any grid upgrades in proportion to their estimated benefits from those upgrades). As such, benefit-based transmission charges would efficiently reduce demand growth in areas likely to require transmission investment.

(b) $61 million from enhanced incentives on beneficiaries of transmission investments to scrutinise proposed transmission investments more closely and provide information that allows Transpower and the Commerce Commission to make better investment choices, including on transmission alternatives.

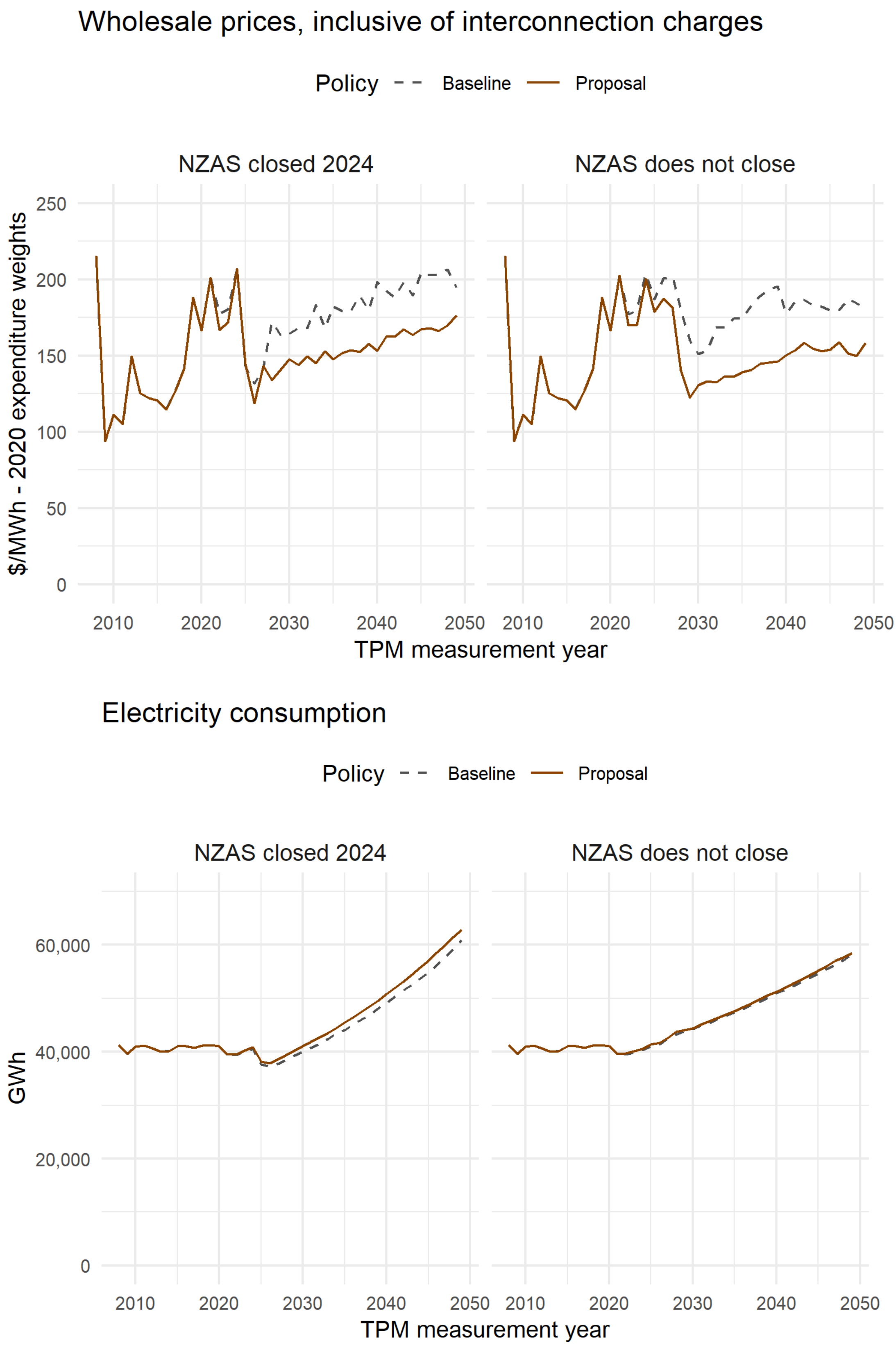
(c) $11 million from increased certainty for investors, which reduces the risk premium or cost of investment in generation, in industrial plant and transmission.

D.17 A range of other costs have been considered and these are valued at $42 million, present value. The bulk of these costs, $38 million, are from TPM development, implementation and operation and legal challenge costs. The remainder are costs from inefficient distortions to load customer investment decisions due to benefit-based charges and allocative efficiency costs from the proposed TPM's transitional cap on changes in transmission charges.

280 Table 13 excludes producer gains, reflecting the Authority's focus on the long-term benefits to consumers. However, the Authority does consider the effects on producer surplus as in the long run consumers are served by regulatory or market settings that are conducive to entry by new suppliers and conducive to efficient investment. See Figure 25.

281 For further detail, see para D.104 - D.107.

Figure 17 Summary of changes in prices and demand



Background

D.18 This appendix provides an overview of the sources and incidence of benefits and costs from the proposed TPM. It also discusses the degree of uncertainty around these estimates in the context of potentially significant changes in generation technologies and increased demand for electricity as New Zealand transitions to a low-emissions economy over the coming decades.

D.19 The CBA framework and methods are very similar to those used in the Authority's analysis of the TPM Guidelines in 2020 (the Guidelines CBA). The underlying CBA methodology was thoroughly reviewed and tested during the 2020 Guidelines process, changes have been made to address feedback, and the Authority is comfortable that any issues raised have been properly addressed.

D.20 The CBA presented here does include some significant changes in input assumptions to reflect information which has become available since the Authority's decision on the Guidelines, as well as changes that reflect design detail of the proposed TPM. The Guidelines CBA had to make various assumptions in modelling a new TPM, since its detailed design had yet to be developed.

D.21 The focus is on costs and benefits of the proposed TPM against continuing with the current TPM. Alternative scenarios are based on key variations to the proposed TPM that are available under the Guidelines, as discussed in this consultation paper.

D.22 The 2020 Decision paper already considered the benefits and costs of a substantial range of alternative approaches to transmission pricing – including through a quantitative CBA for a subset of options. The Authority does not repeat that analysis, instead the focus is now on options available under the Guidelines.

Methods

D.23 As for the Authority's Guidelines CBA, the analysis here is based on:

(a) a model of the effects of changing transmission charges on the use of the grid and on wholesale electricity market activity (grid use model)

(b) other models for analysing investment effects in terms of:

  (i) impacts of benefit-based charges on the efficiency of investment decisions by generators and load customers

  (ii) benefits from a more durable TPM, increasing certainty for investors

  (iii) potential for more efficient transmission investment due to greater scrutiny of investment decisions.

(c) an assessment of expected costs associated with the implementation and development of a new TPM.

D.24 Relative to the Guidelines CBA, several key modelling assumptions, such as rates of demand growth, have changed materially and aspects of the modelling has changed to reflect the specific design of the proposed TPM. An overview follows. The CBA Technical Paper details the methods used in the CBA.[282]

[282] The CBA technical document and supporting files will be published shortly after the release of this consultation document.

Grid use model

D.25 The grid use modelling considers the interdependent effects of transmission charges on generation cost, consumer demand and wholesale electricity prices at different geographical locations on the grid, and generation investment. These are the key components needed to understand the effects of changing the approach to transmission pricing.

D.26 The model is a necessarily simplified, but tractable, representation of reality. It does not pretend to be perfectly accurate (which is of course not possible when making long range projections) but aims to provide sufficient detail and realism to give the Authority confidence that:

(a) it has a reasonable estimate of the likely impact and materiality of the net benefits of different options, and

(b) the CBA's estimates are robust to a range of reasonable input assumptions.

D.27 The model is based on a robust empirical approach to estimating key relationships or linkages between transmission charges, wholesale energy prices and wholesale demand for electricity in New Zealand by time-of-use and in different geographical areas.

D.28 The model uses a representation of the transmission grid consisting of 14 separate geographical areas (backbone nodes). Figure 18 shows the location of these backbone nodes and illustrative transmission line connections between them.

Figure 18 Simplified transmission grid with 14 backbone nodes

D.29 The grid use model analysis proceeds by setting a baseline for expected market evolution (demand, investment, prices) and then calculating changes in the market when transmission pricing changes.

Baseline

D.30 The model baseline has been updated since the Guidelines CBA to account for new information which has since become available. Specifically, it is based on three main sources of information:

(a) The Climate Change Commission's (CCC) demonstration pathway in its May 2021 final advice to the Government, used for assumptions regarding:

(i) demand growth

(ii) gas prices

(iii) emissions prices

(iv) Tiwai closure

(v) generation plant decommissioning

(vi) rates of decline in the capital cost of new solar and wind plant.

(b) The Ministry of Business Innovation and Employment's (MBIE) 2020 generation cost studies, for assumptions regarding capital and operating costs of new generation plant.

(c) Transpower's integrated transmission planning schedules and disclosed expenditure plans, for assumptions regarding future capital and operating expenditure and allowable interconnection revenue.

D.31 Table 14 provides a high-level summary of the main baseline assumptions in the modelling, most of which are taken directly from the CCC (2021).[283] In addition to these assumptions, we assume that no new thermal generation is installed, to reflect the Government's 100% renewables target. As policy levers to achieve that target have not been announced, we have not assumed 100% renewables by 2030.

D.32 Consistent with the CCC's demonstration pathway, the Tiwai Point aluminium smelter (NZAS) is assumed to close at the end of 2024 and the Huntly Rankines are expected to be decommissioned at that time. The exogenous rate of demand growth in the baseline is consistent with electricity demand rising from around 40,000 GWh currently to approximately 60,000 GWh in 2049.

D.33 However, an alternative baseline is modelled in which NZAS does not close and the Huntly Rankine units are decommissioned in 2026. The scenario where NZAS does not close includes a lower rate of exogenous demand growth, in order for total demand to remain consistent with CCC modelling. This is so that total demand will reach the same level in 2049 in the central scenario where NZAS does close – absent any price effects that reduce demand growth. Regardless, assumed baseline demand growth is significant.

D.34 Transmission revenue under the baseline is shown in Figure 19 with a split for load and generation customer charges. Revenue is expected to grow gradually in coming

283 https://www.climatecommission.govt.nz/our-work/advice-to-government-topic/inaia-tonu-nei-a-low-emissions-future-for-aotearoa/modelling/

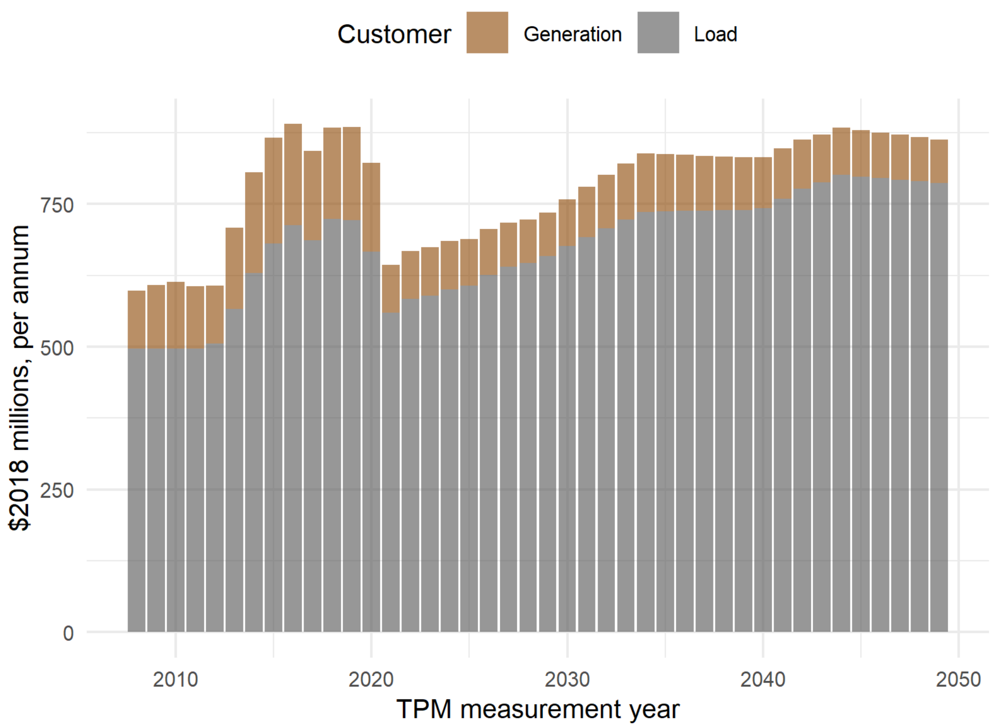
years, reflecting rising capital expenditure. In the baseline (that is, under the current TPM), generation customers' charges are expected to average around 11% of interconnection charges, down from the current 13% share. Generators' shares of charges tend to rise and fall much more than load customers' shares under the current TPM, in line with expenditure on the HVDC.

Table 14 Baseline assumptions

Assumption	Sample values
Wind generation capital costs (LRMC)	
Range for $ per MWh in 2020 ($2018)	$66.9/MWh - $97.3/MWh
Range for $ per MWh in 2035 ($2018)	$61.8/MWh - $88.5/MWh
Average annual growth	-0.80%
Utility scale solar generation capital costs	
Range for $ per MWh in 2020 ($2018)	$87.2/MWh - $113.4/MWh
Range for $ per MWh in 2035 ($2018)	$59.8/MWh - $76.9/MWh
Average annual growth	-3.00%
Battery energy storage costs, utility scale	
$/kW in 2020 ($2018)	$984/kW
$/kW in 2035 ($2018)	$588/kW
Annual average growth	-3.4%
Step changes in demand	
Tiwai departure	Close end 2024 -5,322 GWh
Gas prices, central scenario	
$/GJ in 2020 ($2018)	$8.50/GJ
$/GJ in 2041 ($2018)	$10.10/GJ
Average annual growth	0.9%
Emissions prices	
$ per tonne 2020 ($2018)	$28.8/t
$ per tonne 2035 ($2018)	$154.3/t
Average annual growth	11.8%
Exogenous demand growth, average % growth	
Total	2.00%
Population growth	0.74%
Income growth	0.14%
Electrification	1.13%
Exogenous construction	
Turitea wind, stage 1	119 MW, by 2022
Turitea wind, stage 2	103 MW, by 2023
Mt Cass wind	93 MW, by 2023
Tauhara geothermal	152 MW, by 2025
Harapaki wind	176 MW, by 2025
Total	643 MW, 2022-2025
Decommissioning	
Huntly gas/coal units (Rankines)	-500 MW end 2024

D.35 Baseline transmission revenue is based on Transpower's disclosed expenditure plans between now and 2035, and a bespoke assessment of potential new major capex given assumed high rates of demand growth. Substantial investment is expected between now and 2035, including augmentation of the HVDC. After 2035, capital expenditure is expected to be low for a time with sufficient capacity to accommodate demand growth until another assumed investment cycle 2040-2045 (Figure 19).[284]

Figure 19 Baseline interconnection charge revenue



D.36 As shown in Figure 20, wholesale electricity prices are projected to remain high by historical standards for the next few years and then to fall following the departure of NZAS. The prices in Figure 20 (which is for illustration only) are averages over peak, shoulder and off-peak demand periods with the averages weighted by shares of expenditure in 2020.[285]

D.37 Rapid demand growth sees prices steadily rise over time and, beyond 2035, prices in peak periods are projected to become increasingly volatile due to increased penetration of intermittent renewables. That volatility is not apparent in Figure 20 because, for illustration, it presents averages over peak, shoulder and off-peak demand periods.

D.38 High penetration of renewables is supported by declining costs of wind and solar farms with low operating costs of these plants driving prices down – mainly during off-peak or shoulder periods. At the same time, supply during peak periods becomes comparatively constrained, relative to the past, due to rising costs of thermal fuel and no new thermal generation after 2030.

D.39 This does not mean there would be material long-term changes to security of supply – indeed, it is likely that technological change will change the way that peak demand is met and managed, such as through more sophisticated demand response or improved long term energy storage options. To reflect this, some technological

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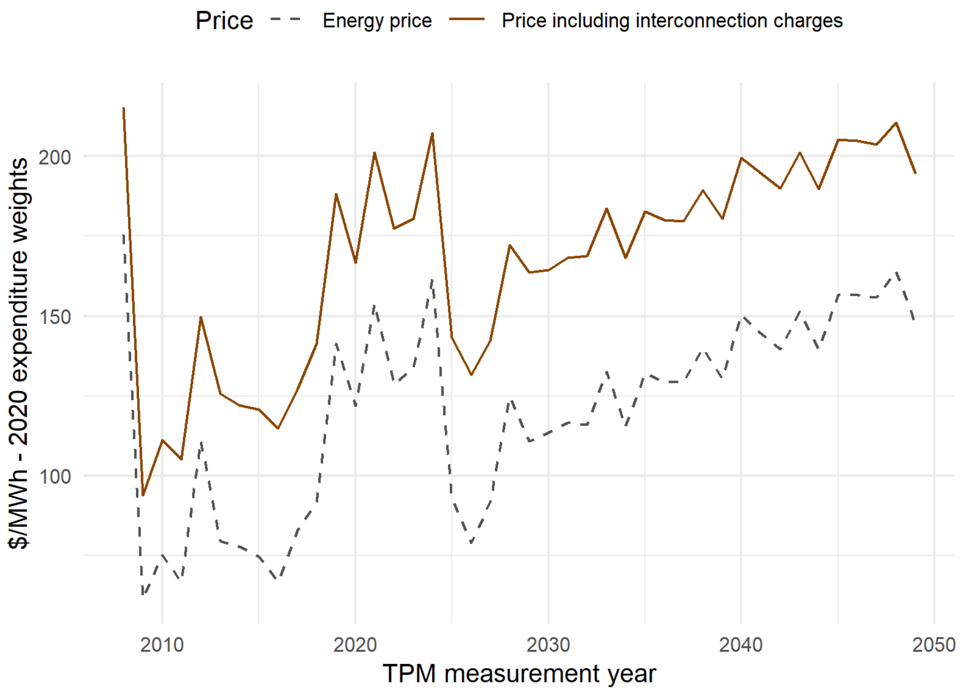
284 The modelling approach and assumptions are detailed in the CBA technical document.

285 The modelling does not rely on these averages – see CBA technical paper.

solutions have been allowed for in the baseline by way of investments that combine intermittent generation with battery storage. However, this is insufficient to avoid volatile peak prices amidst the rapid demand growth associated with electrification of much of New Zealand's primary energy.[286]

D.40 In the baseline, peak demand charges place additional costs on purchasing electricity. These charges constrain demand growth at peak and limit overall rates of demand growth, in so far as consumption of electricity at peak is typically a complement to, rather than a substitute for, electricity consumption at other times of use (though there is substitution).

Figure 20 Projected wholesale prices under the current TPM (baseline)



Proposal

Allocations of transmission charges

D.41 The modelling for the proposed TPM includes the same assumptions as the baseline but with allocations of interconnection charges that reflect the proposed TPM.[287] Allocations of charges are based on:

(a) an opening value for customer shares of benefit-based charges (BBC) on historical investments (based on Schedule 1 of the Guidelines)

(b) residual charges on load customers, for revenue not recovered from BBCs

286 This reflects broader questions on price discovery in the wholesale electricity market under a 100% renewable electricity supply, which the Market Development Advisory Group is investigating: https://www.ea.govt.nz/development/advisory-technical-groups/mdag/mdag-price-discovery-project/

287 Connection charges are not considered in the CBA, as the Guidelines and the proposed TPM do not materially alter this methodology. Under the proposed TPM, there would be no Injection Overhead Component in generators' connection charges; these would instead be recovered through benefit-based charges.

(c) future BBCs, distinguished between:

(i) simple method allocations, modelled here as BBCs for base capex costs, allocated based on Transpower's proposed flows-based matrix that translates regions of investment to regions of benefits

(ii) charges for the Clutha and Upper Waitaki Lines Project (CWULP) and Waikato and Upper North Island (WUNI) major capex projects for which Transpower provided case studies with estimated benefits288

(iii) a default allocation method for other major capex, where half of the benefits are assumed to be economic in nature and are allocated to load and generation customers based on their shares of loss and constraint excess, and half are related to reliability and allocated 99 percent to load customers[289], the same as used in the CBA for the 2020 Decision paper.

D.42 BBCs are assumed to recover asset-specific capital costs and reasonably attributable operating expenditure. Consistent with the proposed TPM, certain overheads, such as non-network operating expenditure, are assumed to be recovered through the benefit-based charge, although non-network capital expenditure (such as furniture in the head office) are assumed to be recovered via the residual charge.

Impacts of proposed charges on grid customer behaviour

D.43 The impacts of the proposed TPM on grid customers vary according to the balance of charges across these different allocations and the extent to which charges distort behaviour.

D.44 The proposed TPM is assumed to impact future generation investment by raising the price at which new investments will break even, where generators face transmission costs. For simplicity, the Authority assumes that generation customers do not face residual charges. Although that is not strictly true, this is a reasonable assumption as residual charges associated with generation will be small.

D.45 For consumers, BBCs are assumed to have different effects depending on whether the charges relate to new investments or to charges on historical investments:

(a) BBCs relating to historical investments are fixed and there is no incentive on consumers to alter their consumption to avoid those charges, although these fixed charges do reduce consumers' purchasing power (an income effect)

(b) In contrast, allocations of the costs from new investments will reflect consumers' consumption at the time that BBCs are allocated. So, we assume that consumers will treat new BBCs as if they are costs per MWh of consumption (across all times of use) at the time that the charges are allocated.[290]

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288 See *Reasons* paper.

289 See CBA technical paper (which will be published in mid-October 2021). This reflects the relative value of lost revenue for a generator per MWh compared to the value of lost load as set in the grid reliability standard.

290 This is a simplifying assumption. Consumers' ability to influence BBCs allocated under the simple method is limited in the short term because allocation factors are set using flow models that are to be revised only periodically, such as every five years. BBCs allocated using the simple method will make up a majority of BBCs for most customers.

D.46 Residual charges are initially fixed based on historical average maximum demand. However, after four years, residual charges are adjusted to reflect lagged rolling average rates of change in electricity use. This creates a muted incremental incentive to reduce consumption to avoid future residual charges. This effect is modelled here by treating residual charges as a per MWh charge, but discounting that cost by 45 percent to reflect that changes in consumption do not begin to affect charges until the fifth year after the change and do not fully affect charges until the eighth year after, and that during that time the total size of the residual charges will also decline.[291]

D.47 Otherwise, revenue is modelled as a fixed charge. Fixed charges have no incremental incentive (ie, price) effects, though they do reduce consumers' purchasing power – an income effect that we reflect in demand calculations.

D.48 Distinguishing the different effects of BBCs and residual charges helps to account for trade-offs embedded in the proposed TPM. For example, higher residual charges and lower BBCs may mean lower costs on producers, higher rates of generation investment and lower prices for consumers in the long run. But higher residual charges reduce consumption and can therefore also delay such generation investment.

D.49 This detail in modelling the effect of different allocation mechanisms in this CBA are to reflect the detailed proposal. This detail, which includes some material design choices in terms of assessing costs and benefits, had yet to be developed at the time the Guidelines CBA was prepared.

Variations in generators' shares of BBCs under the simple method

D.50 The proposed TPM would result in potentially substantial increases in generators' transmission charges.

D.51 The size of any increase is contingent on final design decisions, following consultation, on matter such as:

(a) the balance of benefits between load and generation assumed under the simple method

(b) the proposal to periodically review the balance of benefits between load and generation assumed under the simple method

(c) the extent to which overhead opex costs should be recovered in benefit-based charges.

D.52 These design choices are reflected in the alternative scenarios presented in Table 13.

D.53 The proposed simple method assumes that generation and load customers benefit approximately equally[292] from transmission investments. This would be reviewed five years after a new TPM is introduced and may be changed. As such, the CBA

291 The precise timing of the impact will depend on the month in which a consumer increases demand, whether towards the beginning or towards the end of financial years ended 30 June. Assumptions used to calculate the incremental effect of residual charge adjustments are discussed in the technical documentation.

292 The modelled value is 47% generation customers and 53% load customers.

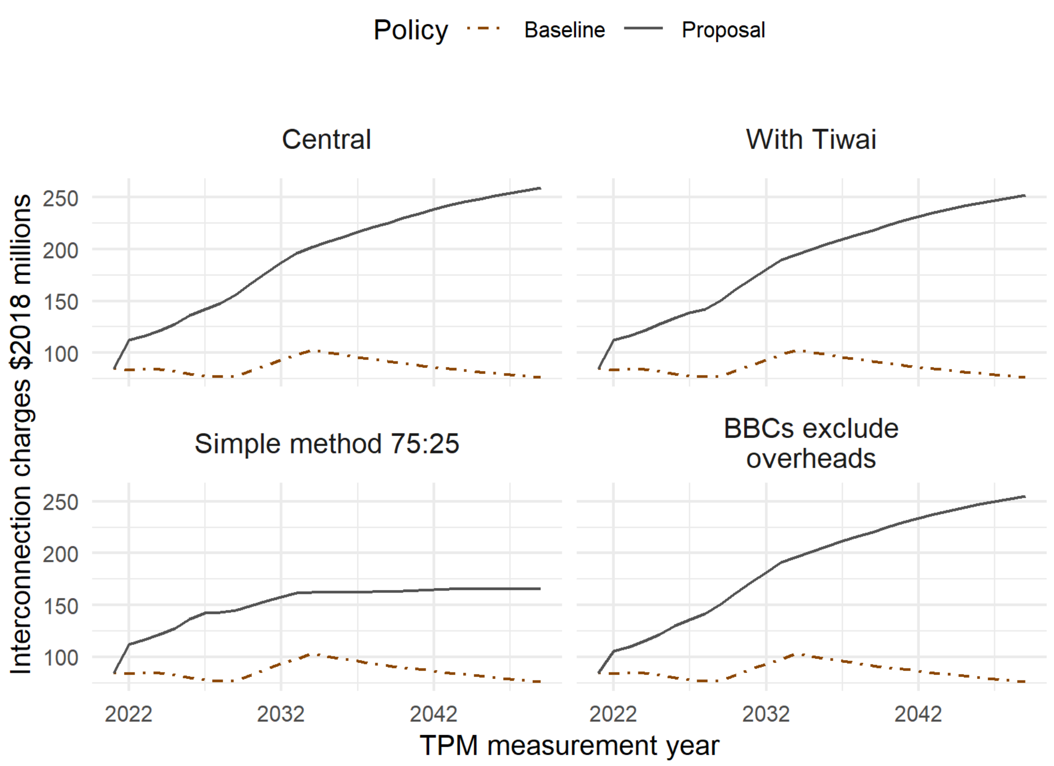
includes an alternative scenario where a review after five years leads to generation customers' share of benefits being reduced to 25%.[293]

D.54 The CBA also includes an alternative scenario where overhead opex, which under the proposal is assumed to be recovered via benefit-based charges, would instead by recovered through residual charges.

D.55 In addition, while the central scenario assumes the smelter at Tiwai Point would exit, the CBA also provides a scenario with the smelter remaining.

D.56 Figure 21 shows changes in generators' interconnection charges under each of the modelled scenarios, compared to the baseline. The central scenario has the highest amount of interconnection charges allocated to generators (a 97% increase relative to the baseline of the current TPM, in present value terms) followed by the scenario with Tiwai remaining (a 93% increase[294]), the scenario with overhead opex excluded from BBCs (a 91% increase) and the scenario with simple method adjusted to a default 25% share of benefits after five years (a 65% increase).

Figure 21 Generators interconnection charges by CBA scenario



D.57 Table 15 below provides an illustration of the distribution of interconnection charges between consumers (load customers) and generators under the baseline and the

293 See discussion of allocations under the simple method in chapter 0. The Authority has also modelled an alternative option with a 75:25 percent sharing of benefit-based charges between load and generators under the simple method from the outset (no change at review), but otherwise the same settings as the central scenario. Net benefits in this scenario are $2.4b within a range of $0.96b – $3.70b.

294 If Tiwai stays open generators' interconnection charges are lower because they are not allocated a portion of the smelter's BBCs.

proposal with generators' shares of benefits under the simple method unchanged after a review (under the central scenario).

D.58 Consumers' shares of interconnection charges fall from 90% under the baseline in the 2044 pricing year to 72% under the proposal, a reduction of $159 million in 2044.

Table 15 Interconnection charge revenue under the baseline and the proposal

Pricing year	**2024**		**2044**	
$2018	$m	% of total	$m	% of total
Generator charges				
Baseline	84	13	86	10
Proposal	112	17	246	28
Consumer charges				
Baseline	584	87	777	90
Proposal	556	83	617	72
Residual charges	390	58	234	27
Benefit-based charges	165	25	384	44
Total	**668**	**100**	**863**	**100**

D.59 The proposed TPM includes five-yearly reviews of power flows that underpin the allocators in the simple method. However, changes to future power flows have not been modelled as part of the CBA and so default regional allocations of BBCs under the simple method are assumed to not change from those presented with Transpower's Reasons paper.

Models of other investment effects

More efficient investment in generation and large load

D.60 The proposal is expected to incentivise more efficient investment by generation and large loads. Under the current TPM, these parties do not face the full costs of any required upgrades to the interconnected grid when making location decisions. As their marginal private costs are lower than marginal social costs, the decisions of these parties may not lead to results that are efficient for society.

D.61 By contrast, the proposed TPM is expected to provide generation and large loads with the incentive to take account of the costs of any such required upgrades. This is because they would face the full costs of any required upgrades to the interconnected grid, through paying the benefit-based charge. Over time, the Authority expects this to result in lower total costs of grid investment.

D.62 In considering this potential benefit, we also consider a potential distortion to investment decisions that could be created by the proposal, if large energy-intensive consumers avoid investing or locating in a region that already has a relatively high benefit-based charge reflecting recent grid investment. We take account of this potential distortion in quantifying the benefit of more efficient investment by generation and load and report it separately below under costs.

D.63 Details of the model used to assess these effects can be found in the technical document.

Increased certainty for investors

D.64 The proposal is expected to increase policy certainty for investors, and thereby reduce the cost of investing, (that is, reduce the return needed to trigger an investment) in generation, load, and transmission. This is based on evidence that uncertainty increases the value of delaying an investment (so-called real options) and increases the level of private benefits required to trigger an investment.

D.65 The approach taken to quantifying these benefits is discussed further in the technical paper and is the same as for the Guidelines CBA. However, the context has changed in so far as the proposed TPM includes a degree of uncertainty over methods for allocating benefit-based charges under the simple method.

D.66 To account for uncertainty about the results of a review of the simple method, it is prudent to discount this source of benefits. So, we consider only the low end of the estimated range of benefits from improved certainty and include in our range of estimates that there may be no benefit from reduced uncertainty.

More efficient grid investment due to scrutiny of proposed grid investment

D.67 A key expected benefit of the proposal is more efficient grid investment due to the enhanced incentives on beneficiaries of transmission investments that pay benefit-based transmission charges to:

(a) more closely scrutinise proposed transmission investments

(b) provide information that enables lower cost transmission investments or transmission investment alternatives

(c) not propose or support inefficient transmission investments.

D.68 The Commerce Commission's grid investment approval processes provide a robust method to test the costs and benefits of investment proposals. Those processes would be enhanced under the proposal as customers would have incentives to reveal information that more accurately reflected a proposal's net benefits or considered the merits of alternatives.

D.69 The Authority considers that the proposal would increase the incentives of interested parties to contribute to the decision-making process around transmission investments (while confining these incentives to parties with an interest in the economic efficiency of investments). To quantify this effect, we assume that these incentives lead to a productivity gain in the long-run costs of transmission investment.

D.70 Our assessment of these potential productivity gains is based on observations around changes to capital expenditure when Transpower's proposed capital expenditure plans are reviewed by the Commerce Commission.

D.71 Scope for improved efficiency of investment can be expected to differ as between projects that are reviewed in some detail by the Commerce Commission and those that are not. That being so, our assessment of potential productivity gains varies by investment category, including whether the investment is for replacement and refurbishment or for grid enhancement and development.

D.72 Notably, only a sample of (base capex) capital expenditure plans are formally reviewed by the Commerce Commission. We expect that the introduction of BBCs would, de facto, bring wider and more comprehensive scrutiny of investment plans.

D.73 Details on assumptions made by category of investment can be found in the CBA technical paper.

Sensitivities and ranges of results

D.74 As this CBA (like all others) relies on assumptions, we test and present the sensitivity of results to different assumptions.

D.75 The final grid use model results are based on averages over hundreds of simulations where key input assumptions are varied. Input assumptions that are varied are:

(a) short-run costs of operating electricity generation

(b) long-run costs of investing in electricity generation

(c) underlying electricity demand growth driven by growth in population and incomes

(d) whether or not the Tiwai point smelter closes in 2024

(e) whether a review of the proposed simple method results in a change in generators shares of BBCs.

D.76 Details are set out in the CBA technical document.

Results

Grid use model

D.77 The proposed TPM benefits consumers by reducing incentives to avoid consuming electricity and significantly reducing incentives to avoid consuming electricity during peak demand periods when it is most highly valued by most consumers.

Increased demand and lower prices

D.78 Figure 22 charts average prices, over the different scenarios in Table 13 and sensitivities, by three categories of time of use and including interconnection charges.

D.79 The cost of electricity during peak periods falls significantly if the RCPD charge is removed.

D.80 In the first few years of a new TPM, higher peak demand is expected to raise peak prices for energy (prices excluding interconnection charges) and offset some of the price reduction caused by the elimination of the peak demand charge. But in the long run, peak prices are substantially lower.

D.81 Off-peak prices increase. This is the result of increased demand off-peak (see below) and also because, as explained at paras D.44- D.47, interconnection charges would be partially linked to consumption of electricity at all times of use, which are represented in the prices in Figure 22.

D.82 Prices during shoulder periods are lower under the proposal than the baseline. This is because, on balance, there is a substitution of demand away from shoulder periods towards peak demand periods, given the change in relative prices between peak and shoulder periods. This substitution effect and resulting lower energy prices is large enough to offset the increase in costs of consuming during shoulder periods due to how the new interconnection charges are partially linked to consumption of electricity.

D.83 Total electricity consumption is on average 1.8% higher under the proposal (central scenario) than under the baseline. This is because the cost of an additional MWh of electricity falls.

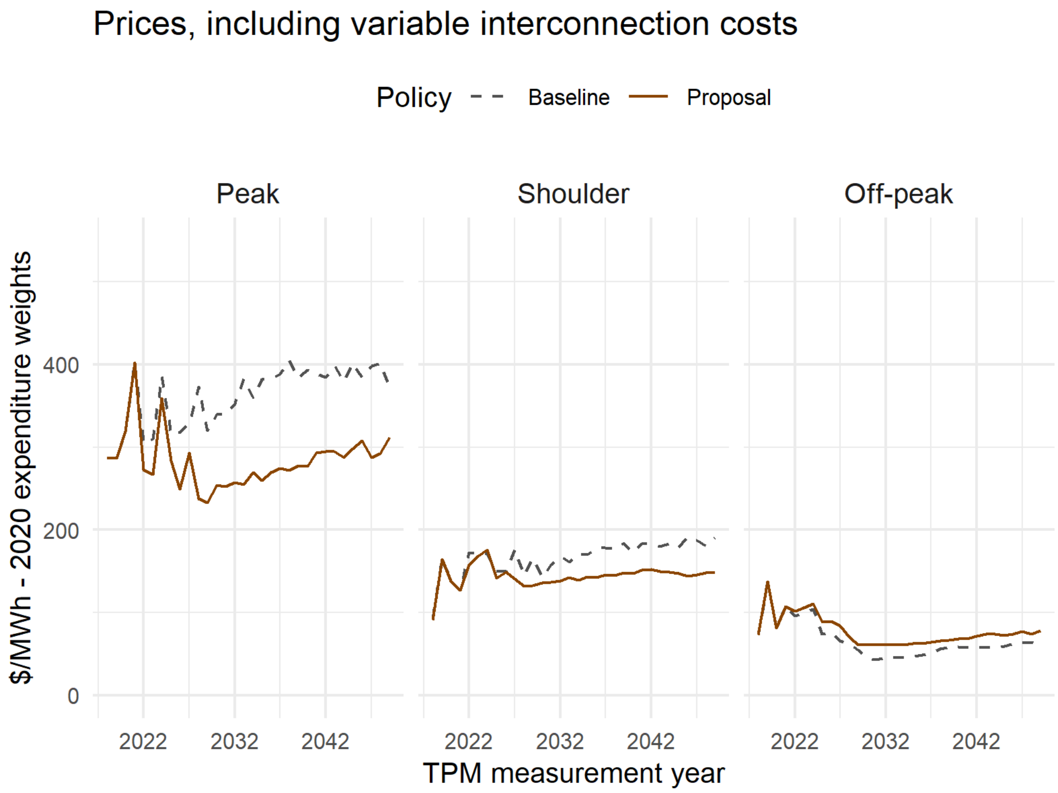
D.84 The declining cost of electricity reflects both a reduction in overall interconnection charges to consumers and a shift to interconnection charges that includes a substantial portion of fixed charges – so that those who wish to consume more electricity face smaller increases in electricity costs.

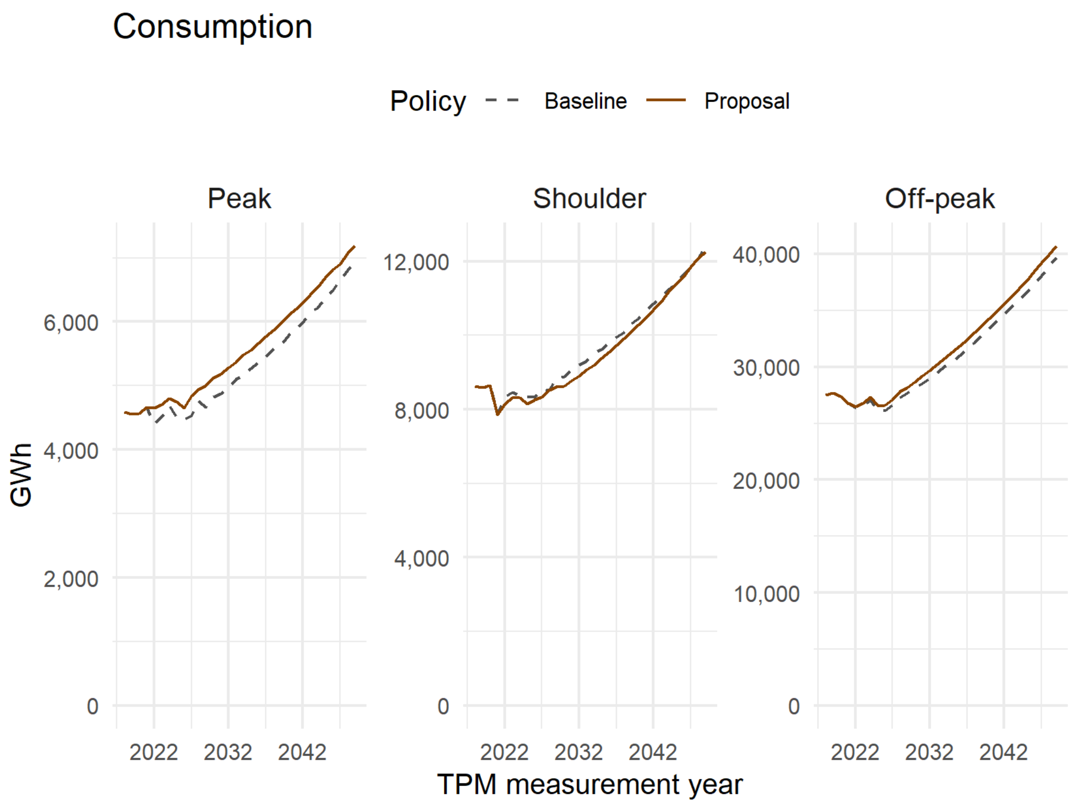
D.85 The percentage increase in consumption is largest for peak periods where prices fall the most. Peak demand is on average 4.3% higher under the proposal (central scenario).

D.86 Off-peak demand also increases, by 2.2% on average in the central scenario relative to the baseline. This reflects the overall reduction in cost of consuming additional electricity and complementarity between demand at peak and demand during off-peak periods. That is, when prices fall on average across all times of use this encourages new or expanded uses of electricity regardless of time of use.

D.87 Demand during shoulder periods falls by 0.4% on average as relative price effects dominate – shifting demand out of shoulder periods and into peak demand periods.

Figure 22 Prices and consumption by time of use





Increased consumer surplus

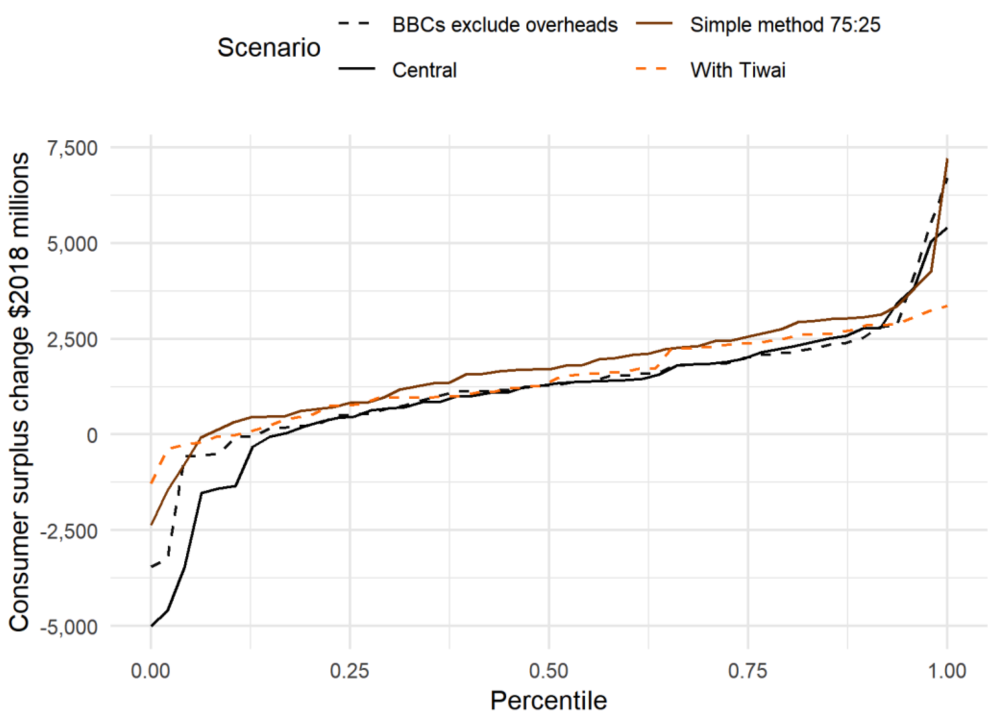
D.88 The gross consumer welfare impacts of these changes to prices and demand have been valued at a probability weighted average of $2,303 million present value in 2018 dollars. The net change in consumer surplus, after taking out the effect of reduced interconnection charges (a transfer), is $1,098 million present value.

D.89 Reduced interconnection charges (of $1,205 million present value) are a direct gain to consumers. However, it increases generators' interconnection charges, and this comes with potential efficiency costs in terms of discouraging new investment in generation or distorting investment decisions.

D.90 The effects of increased charges on generators, in terms of consumer welfare changes, are shown in Figure 23. This shows the range of results for changes in consumer surplus across the main scenarios modelled.

D.91 The chart shows that the scenario with the lowest share of charges paid by generators (25% of charges under the simple method, after a review) produces the highest consumer welfare changes. This suggests that, on balance, there are efficiency gains from erring on the side of recovering costs from consumers rather than generators – at least with the range of the scenarios being considered here.

Figure 23 Consumer surplus changes, ranges of results



D.92 The scale of estimated consumer surplus changes relies partially on an assumption of efficient pass-through of transmission charges to retail customers. In practice, changes to distribution and retail prices may not occur overnight. However, it is reasonable to assume that transmission costs will be passed on in ways that reflect the drivers of transmission charges in the new TPM.[295]

D.93 Most distributors currently allocate costs of transmission charges in accordance with customer groups' contributions to the key driver of transmission charges (peak demand). Distributors are reforming their prices to reflect the 2019 distribution pricing principles, and the Authority expects distributors would pass through transmission charges in a way that broadly reflects their structure.

Distributional effects by backbone node

D.94 Table 16 indicates that consumers in almost all regions would be better off as a result of the proposed TPM. One exception is Whakamaru, where transmission charges would initially increase significantly from a very small base. This is due to the extent of local geothermal generation around Taupō, reducing net measures of peak demand and thus current transmission charges. Also, large industrial load at Tarukenga has a similarly large increase in transmission charges because it no longer avoids transmission charges altogether by managing peak consumption and sourcing electricity from local embedded generation.

295 Price pass-through need not be immediate and to all customers. It might be that pass-through occurs first for marginal customers. And pass-through can occur in numerous ways that do not rely on changes to traditional retail prices. For example, it could occur through retailers contracting with customers (potentially via a flexibility trader) to control some of their load remotely (water heating, space heating, etc). This is consistent with IPAG's work on efficient demand response: https://www.ea.govt.nz/assets/dms-assets/28/Transpower-DR-programme-review-draft-memo.pdf

Table 16 Distributional effects by backbone node – central scenario

Net benefits, % of baseline expenditure wholesale market energy costs plus interconnection charges (PV). Note these distributional effects are NOT net of transfers.

Backbone node	Large industrial	Non-residential	Residential	Total
Marsden	--	1.4%	2.7%	1.9%
Otahuhu	0.2%	3.4%	5.1%	3.7%
Huntly	0.9%	2.7%	4.2%	3.0%
Tarukenga	-4.9%	2.8%	4.4%	3.2%
Whakamaru	--	-3.9%	-4.7%	-4.2%
Stratford	0.2%	2.4%	4.1%	3.0%
Redclyffe	1.2%	3.5%	5.4%	3.7%
Bunnythorpe	1.7%	2.5%	4.0%	2.9%
Haywards	--	3.9%	5.7%	4.7%
Kikiwa	--	3.4%	4.9%	4.0%
Islington	2.2%	3.4%	5.2%	4.1%
Benmore	--	5.1%	6.8%	5.7%
Roxburgh	--	2.6%	4.0%	3.2%
Tiwai	1.3%	3.4%	4.9%	2.5%

Recovering overheads in BBCs may reduce the efficiency of the proposed TPM

D.95 Results suggest that recovering overhead opex in benefit-based charges may have efficiency costs. On one measure of central tendency, the net benefits of the central scenario are lower than for the scenario where overhead opex is recovered through residual charges, in which net benefits would be $321m greater.

D.96 This result does vary across the choice of measure of central tendency as shown in Table 17. Median net benefits are greater with overhead opex recovered in benefit-based charges rather than in the residual.

Table 17 Variations in CBA results by measure of central tendency

Estimated net benefits ($m)	Central	Tiwai open	Simple method to 75:25 at review	Overhead opex in RC
Weighted mean	1,253	1,580	2,377	1,574
Mean	1,249	1,610	1,924	1,487
Median	1,485	1,534	1,886	1,461

D.97 This difference between median results and average results reflects several large negative results in the central scenario when overheads are recovered in benefit-based charges, as can be seen in Figure 23. This figure also shows that for the majority of sensitivities shown there is very little difference in the change in net consumer surplus whether overhead opex is recovered through benefit-based or residual charges.

D.98 That said, the findings of the CBA do point to improved efficiency gains from lower charges on generators. Recovering overheads in benefit-based charges means, amongst other things, increasing generators' shares of interconnection charges and potentially distorting generation investment.

Higher demand drives increased investment and higher producer surplus

D.99 The Authority pursues improvements in the electricity market for the long-term benefit of consumers. They are likely to be served by regulatory or market settings that are conducive to entry by innovative suppliers and conducive to efficient investment. As such, the Authority also considers the effect of a policy change on producer surplus to ensure gains to consumers do not undermine profitability and incentives to invest.

D.100 Under the proposed TPM, more rapid rates of demand growth drive increased investment in electricity generation and higher electricity expenditure to pay for it (a 6% increase in the central scenario). See Figure 24.

D.101 This higher activity level translates into higher producer surpluses, in line with larger amounts of capital invested (see Figure 25). That is, generators' operating surpluses must increase to compensate them for increased capital investment to meet increased demand, and increased transmission charges that result from the proposed TPM. The extent of growth in producer surplus is consistent with rates of return used in the Authority's modelling and applied to the increased capital investment under the proposed TPM. The central scenario results in a total surplus of $6.7b.

Figure 24 Increased investment

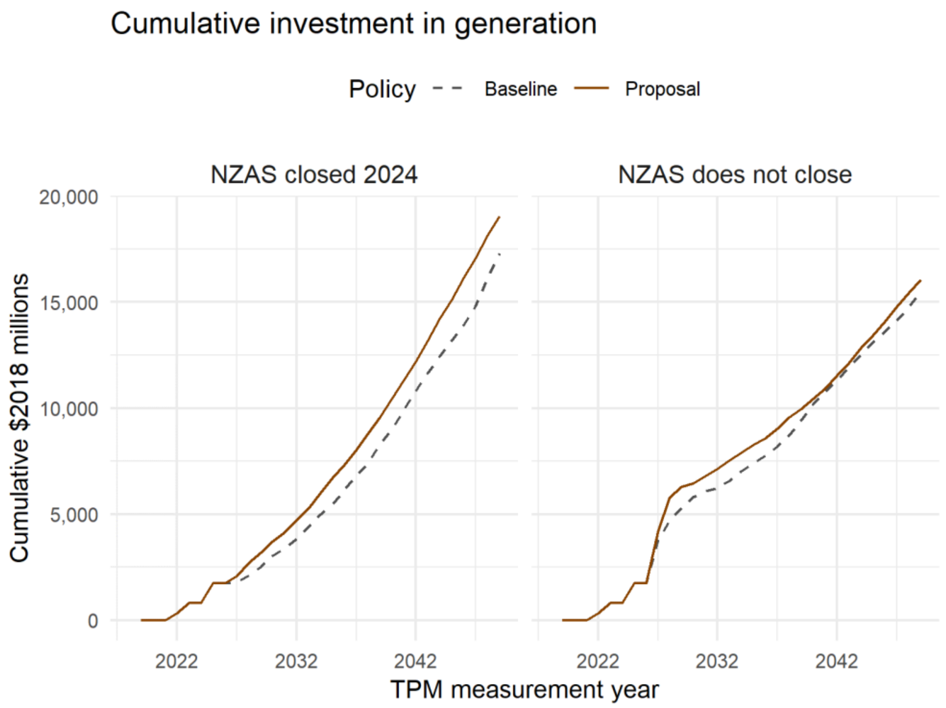
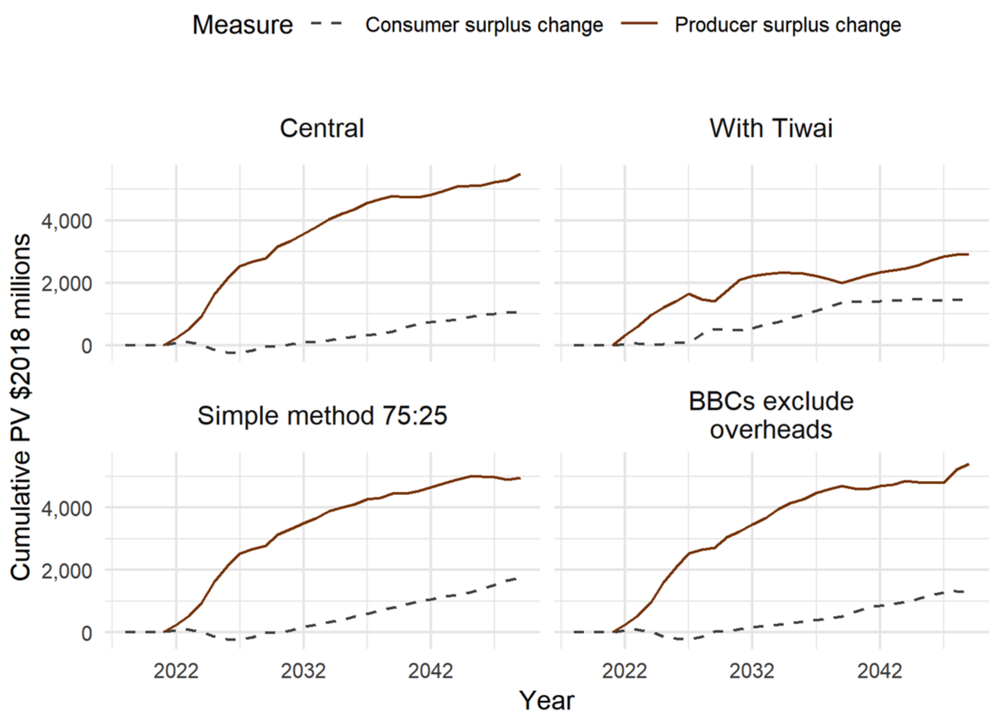


Figure 25 Changes in consumer and producer surpluses



Increased transmission investment to accommodate increased peak demand

D.102 Increased peak demand will likely bring forward Transpower's grid investments and this effect is likely to be strongest if NZAS closes.

D.103 We estimate the cost of transmission investment brought forward from higher peak demand to range from $159 million with NZAS to $281 million without NZAS.

D.104 The higher amount of investment brought forward when NZAS closes in 2024 reflects substantially lower peak prices when NZAS closes and so a significant increase in peak demand outside of the lower South Island. Thus, the cost of investment brought forward relates to investment outside of the lower South Island to allow electricity to be transported to meet this increased demand.

D.105 The benefits that are brought forward by accelerated grid investment are substantial. However, the measure of benefits used in the CBA (changes in the costs of losses and congestion) is linked to market prices, and market prices decline because of the increased penetration of increasingly cheaper wind generation. This means the quantified benefits from bringing forward transmission investment (in terms of reducing the cost of losses and congestion) are less than the cost of bringing transmission investment forward.

D.106 Benefits from transmission investment brought forward are valued at $243 million without NZAS and $154 million with NZAS. This implies a net cost of accelerated investment ranging from $5 million (present value) with NZAS to $38 million without NZAS.

D.107 This quantified net cost is likely to be offset by additional unquantified benefits from improvements in reliability. Reliability benefits are likely to be substantial given that peak demand is materially higher under the proposal.

Investment efficiencies

D.108 The proposed BBCs are expected to improve the efficiency of transmission investment, through deferrals and more effectively targeted investment. These gains in efficiency are valued at $179 million.[296]

D.109 The largest benefits come from more efficient investment in generation and load ($106 million, present value, Table 18). With high expected demand growth, there are material gains from ensuring that investors consider the implications of investing in areas where they could exacerbate transmission capacity constraints.

Table 18 Investment efficiencies

	Central	Lower bound	Upper bound
More efficient investment in generation and load	106	30	611
Reduced uncertainty for investors	11	0	29
Scrutiny of major capex	36	8	65
Scrutiny of base capex	25	4	57
Total	**179**	**42**	**761**

D.110 Investment scrutiny is expected to have the second largest impact on investment efficiency, valued at $61 million with a range of $12 million to $122 million. These ranges reflect uncertainty of the scale of efficiency gains, conditional on expected future capital investment. There is scope for larger gains if capital expenditure is higher than expected. The underlying assessment (parameters) of potential productivity improvements remains as it was in the Guidelines CBA.

D.111 The smallest potential benefit comes from reductions in uncertainty. As discussed above, there is much less certainty about this benefit given that the proposed TPM contains provision for a review of the simple method early in the life of the new TPM. Hence the central estimate used here is the one that was the lower bound in the Guidelines CBA, the new lower bound is zero and the upper bound is the mean used in the Guidelines CBA.

D.112 Table 19 provides a breakdown of estimated benefits from more efficient investment in load and generation, plus the scale of potential costs from inefficient deferral of demand investment (mean value of $3.0 million, picked up under ‘other costs’).

Table 19 More efficient load and generation investment decisions

Value	5th percentile	50th percentile	Mean	95th percentile
Net benefit	29.7	105.1	200.0	601.0
Gross benefit	29.9	106.5	203.0	610.7
Generation benefit	1.0	12.3	15.2	39.1
Demand gross benefit	13.5	90.9	187.8	598.2
Demand cost	0.1	1.0	3.0	10.8
Demand net benefit	13.3	89.5	184.8	586.8

Other costs

D.113 Our estimates of costs, outside of those that are explicitly and implicitly factored into the results above, are dominated by costs of TPM development, implementation and

296 Net of costs from legal challenges relating to scrutiny of major investment decisions but excluding any other offsetting costs associated with benefit based charges.

operation. Our estimates of these costs rely heavily on Transpower's assessments of costs from implementing a new TPM.

D.114 We estimate costs to be $42 million (present value), with a range of $20 million to $68.4 million. Of these costs:

(a) Development costs are valued at $8.8 million, including stakeholder participation and legal challenge costs.

(b) Implementation costs are valued at $19.6 million, including cost of ICT and other system changes for Transpower and designated transmission customers.

(c) Ongoing operational and administrative costs are $9.3 million.

(d) $4.1 million relates to the cost of load not locating in regions with recent grid investment and the efficiency cost of the transitional price cap.

Consultation questions

Do you have any comment on the cost benefit analysis?

Appendix E First mover disadvantage, worked examples of approaches

E.1 Chapter 4 explains it may be efficient for Transpower to build excess 'anticipatory' capacity at grid connections for future, uncertain, customers. A Type 2 first mover disadvantage (FMD) issue arises if an initial connecting customer must carry the full cost of anticipatory connection capacity in excess of its own requirements, until subsequent movers connect.

E.2 Having to carry the full cost of anticipatory capacity would create uncertainty and cost for the first mover that may discourage it from agreeing to anticipatory capacity, even if building this now would be efficient over the longer term (because building one bigger asset now is usually cheaper than building two smaller assets that add up to the same capacity - one now, one later).

E.3 This FMD could lead to inefficiently undersized connection investments or deter connection by first movers. These effects would lead to higher transmission costs overall and could lead to businesses slowing down their electrification, or to generation investment being delayed.

E.4 Three approaches for addressing the Type 2 FMD - allocating costs relating to anticipatory investments - are presented in chapter 4. These are:

(a) A benefit-based approach (with an alternative, complementary, variation that adds a limit above which a different allocation method would be used).

(b) Pool and share (full socialisation), with cost recovery from all connected customers in proportion to their connection capacity (or alternatively by including relevant costs in the residual).

(c) Temporary socialisation.

E.5 A further alternative could be to restrict the chosen FMD approach to only brownfields (upgrade) investments – this restriction could be included with any of options a) to c) above.

E.6 As explained in Chapter 4, the Authority prefers a benefit-based approach because it avoids spreading costs to parties who clearly don't benefit, and targets costs enough to motivate identified (regional) benefiting customers to engage with Transpower and the Commerce Commission (if applicable) on the merits of additional capacity. The Authority views temporary socialisation as the next best option.

E.7 This appendix provides further details and worked examples of the core options a) b) and c) above. In these examples we refer to anticipatory connection capacity as X and the first mover's requested connection capacity (including any headroom for that same party) as C.

E.8 These worked examples were calculated using Transpower's BBI regional allocation tables as they were in July 2021. These tables were later updated, so the examples in this appendix serve to illustrate and compare the different allocation methods for anticipatory investments. These examples should not be read as precise calculations of the cost allocation outcomes that will eventuate under each method.

Illustrating the benefit-based approach to allocating the costs relating to anticipatory connection charges

E.9 Under the proposed benefit-based approach to allocating connection charges relating to anticipatory investments:

(a) costs relating to the capacity the first mover needs would be paid by that party, ie, as currently occurs

(b) costs relating to the anticipatory capacity could be allocated to other customers that are expected to benefit rather than to the first mover, until subsequent movers connect:

(i) a new class of ‘anticipatory capacity BBIs’ could be created

(i) the covered cost of these anticipatory capacity BBIs would be allocated using the regional allocation tables Transpower will use for setting BBCs for low-value BBIs[297]

(ii) the relevant allocators would be selected depending on whether the anticipatory capacity is expected to be for the connection of load or generation:

- for load, costs would be allocated to local and upstream generation
- for generation, costs would be allocated to local and downstream load.[298]

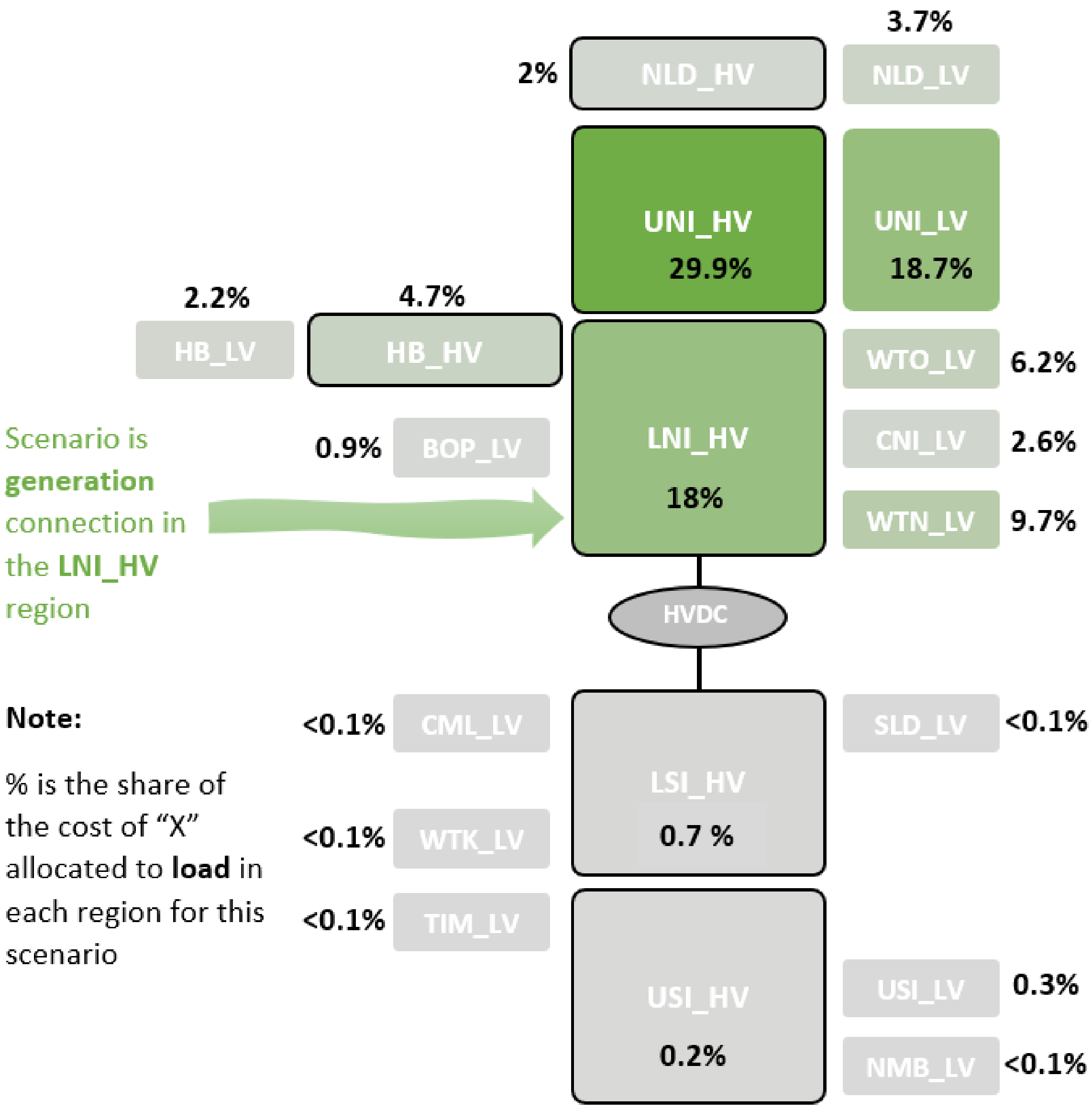
E.10 As anticipatory capacity is taken up by second and subsequent movers, it reverts to standard connection asset cost recovery. Figure 26 illustrates how costs relating to X would be allocated for an anticipatory capacity BBI in the lower North Island high voltage region made in anticipation of upcoming new generation assets connecting.

E.11 In this situation, beneficiaries are mostly local and downstream load, across the North Island. The costs would be widely spread, mostly to downstream load across the upper North Island and lower North Island, and to local load in the same regions.

[297] The BBC simple method is discussed at chapter 5.

[298] In the event the additional capacity was built in anticipation of both load and generation connecting in the same location, costs could be allocated as per any other low-cost BBI investment (that is, to within-region customers, upstream generation and downstream load).

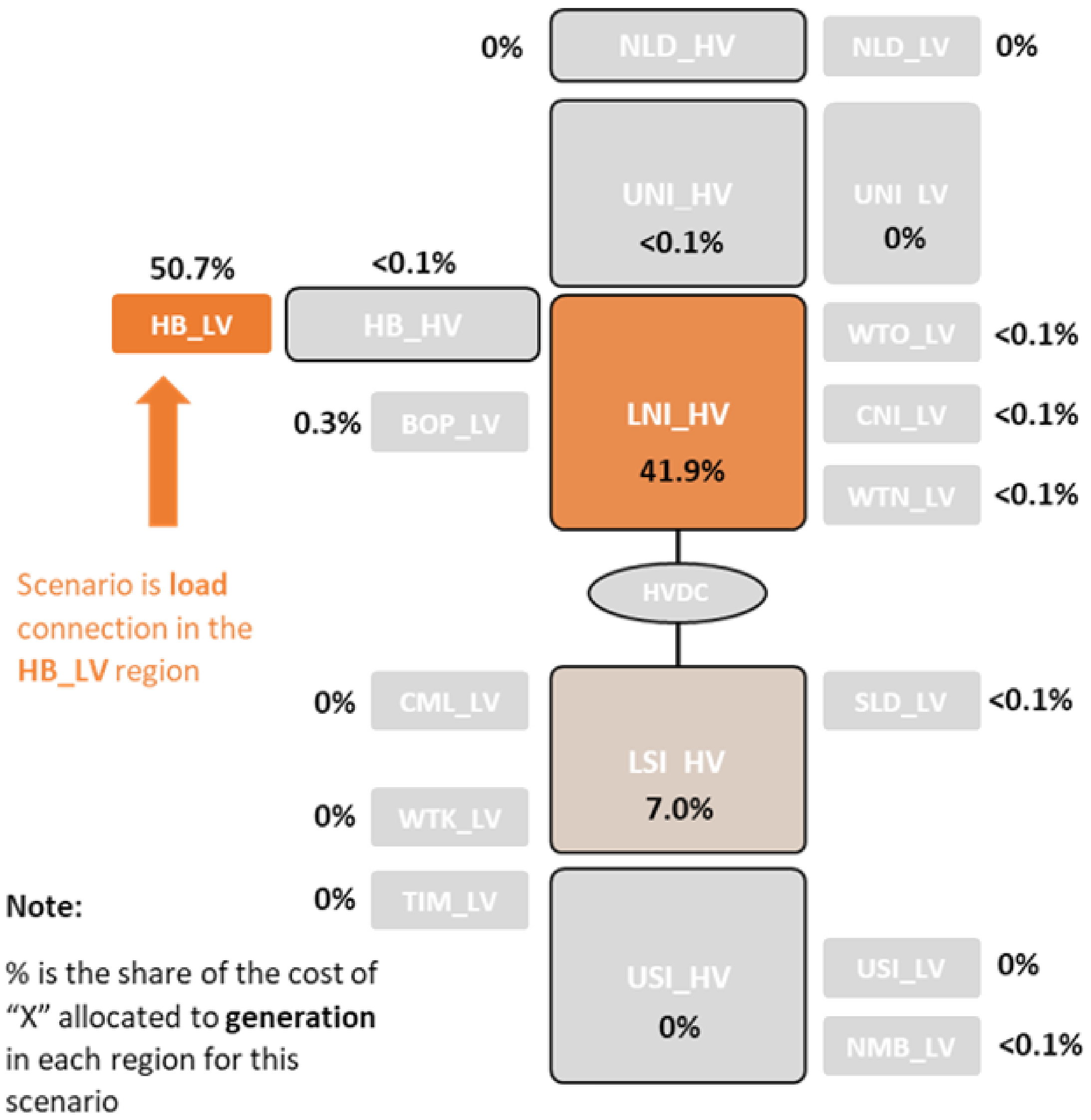
Figure 26 The BB approach, lower North Island high voltage region.



E.12 Figure 27 illustrates how costs relating to X would be allocated for an anticipatory capacity BBI in the Hawkes Bay low voltage region made in anticipation of a new load connection, with costs allocated to local and upstream generation.

E.13 This situation illustrates an investment for which the benefit-based approach would identify beneficiaries as widely spread. Beneficiaries are generators that would supply the new load. Benefiting generation is mostly spread across the lower North Island high voltage and Hawkes Bay low voltage regions, with some allocation also to the South Island.[299]

Figure 27 The BB approach for anticipated capacity for load in the Hawkes Bay low voltage region.

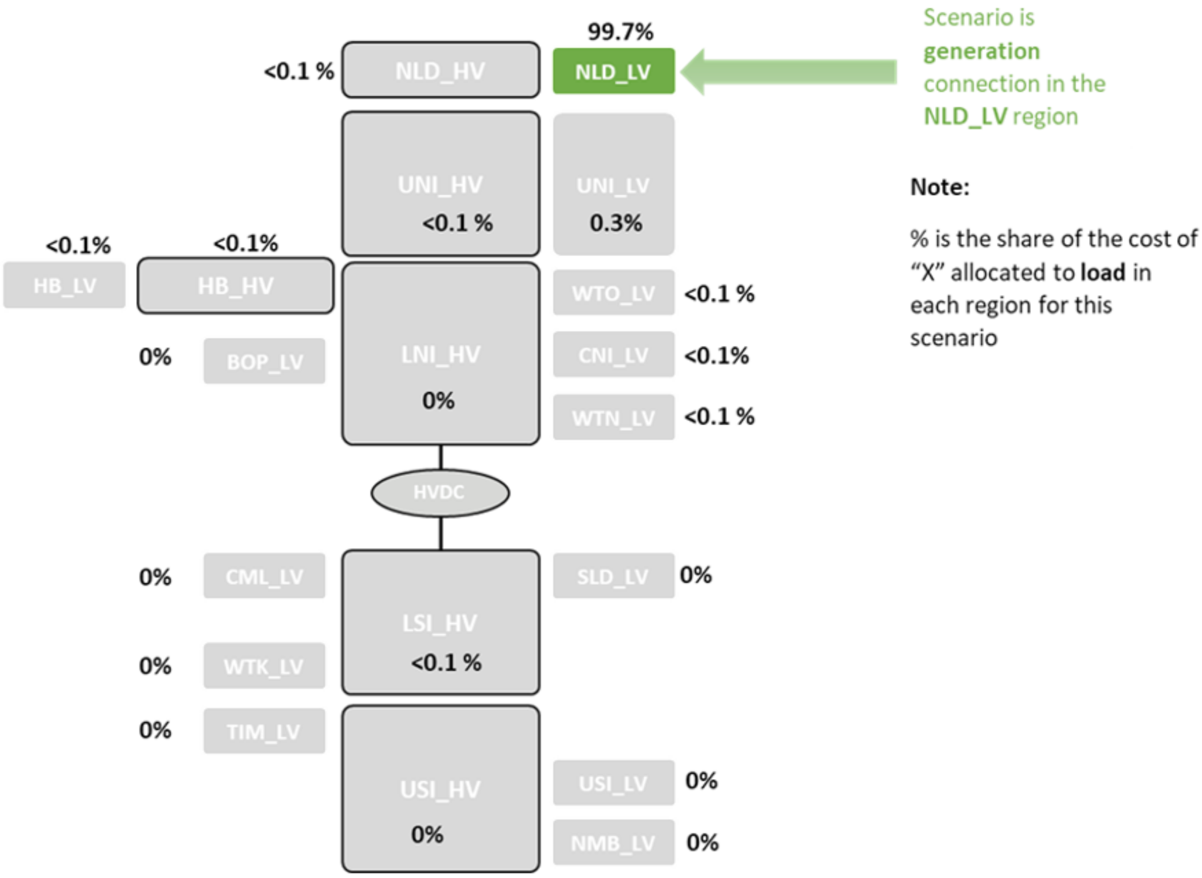


299 Regions are defined as per Transpower's simple method. The simple method assigns transmission customers to particular regions (such as the Hawkes Bay low voltage region).

E.14 Figure 28 illustrates how costs relating to X would be allocated for an anticipatory capacity BBI in the Northland low voltage region made in anticipation of upcoming new generation assets, with costs allocated to local (and some downstream) load.

E.15 This situation illustrates an investment for which the benefit-based approach would identify beneficiaries largely in a single region: in this example, over 99 per cent of the costs fall on the Northland low voltage region. For a *small* investment to enable new generation, this would be appropriate. That is because the grid investment would not only benefit the new generation; that new generation – and so, the grid investment – would also bring benefits for load customers in Northland (for example, improved reliability of supply and lower wholesale electricity prices).

Figure 28 The BB approach, Northland low voltage region.



E.16 However, for a *large* investment that enables substantial new generation, the situation could be different. Large volumes of new generation could change Northland from an importing region to an exporting region. In these circumstances the benefits of new generation could flow not only to Northland customers, but also to a wider group of benefiting customers. Further, a situation where the costs of X are unusually large and fall disproportionately on a small group of (non-connecting) customers may not be appropriate. So Chapter 4 describes a possible alternative mechanism under which there could be an upper limit, above which the benefit-based approach would not apply. Under this alternative option, above-limit costs would *not* fall only on consumers in the Northland low-voltage region.[300]

E.17 Figure 29 illustrates how the benefit-based option allocates the cost of C and X across the first mover (1M), the second connecting party (2M) and wider identified beneficiaries, at years 4, 9 and 16.

E.18 The left and right side panels show the allocations if the second mover arrives after five years, and if the anticipated second mover does not arrive. The illustration uses the following settings:

(a) C provides 100 MW for $20m and X doubles capacity for an additional $10m.

(b) There are two movers, each with peak usage of 100 MW.

(c) C is financed through a 10-year NIC (new investment contract).[301]

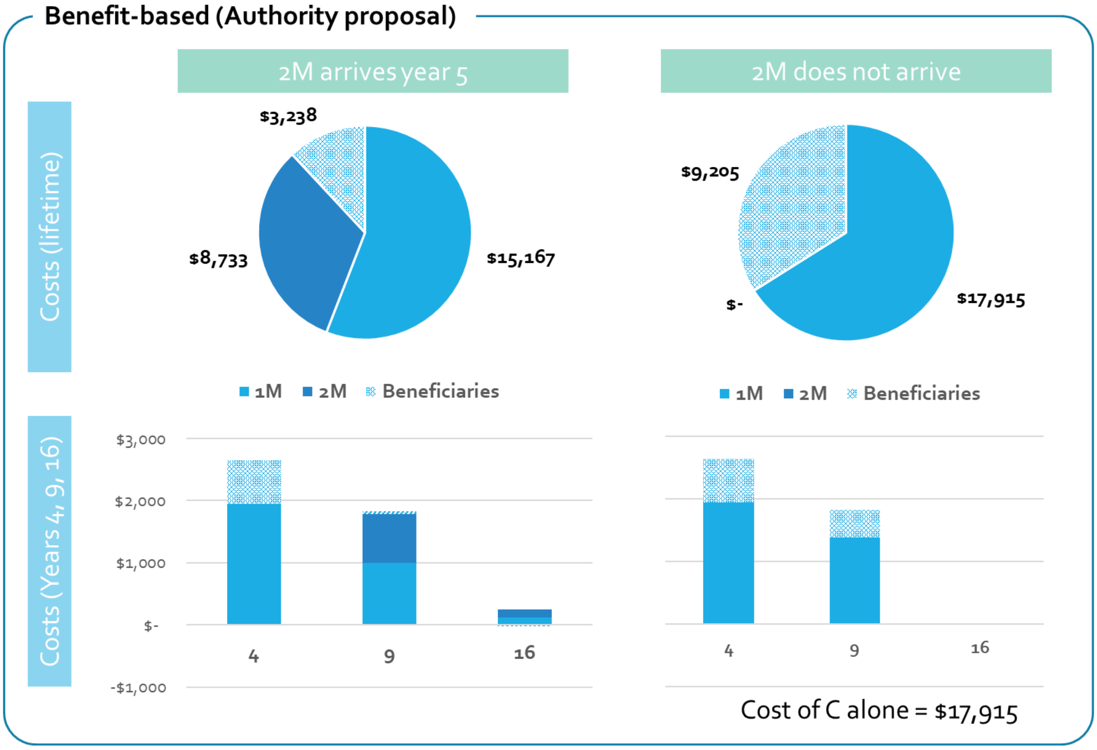
(d) In Scenario A, the second mover connects in year five.

(e) In Scenario B, the second mover never connects.

300 This is described in Chapter 4.

301 The analysis uses Transpower's RCP3 cost of capital settings and uses a discount rate of 7% (to reflect a customer-centred view of the cost of finance). With these settings, the first mover would pay $17,915m if no X were built. This is lower than the $20m nominal cost because the first mover enjoys access to Transpower's low-cost vendor financing.

Figure 29 FMD allocations for benefit-based option



E.19 Key observations for this approach are:

(a) it produces almost the same allocation of costs (across the first mover, second customer and wider beneficiaries) as the full socialisation option (see below), except:

(i) the risk borne by others is slightly higher because the first mover does not carry any of the cost of X

(ii) the parties bearing the holding cost of X are more likely to benefit from X if it is used.

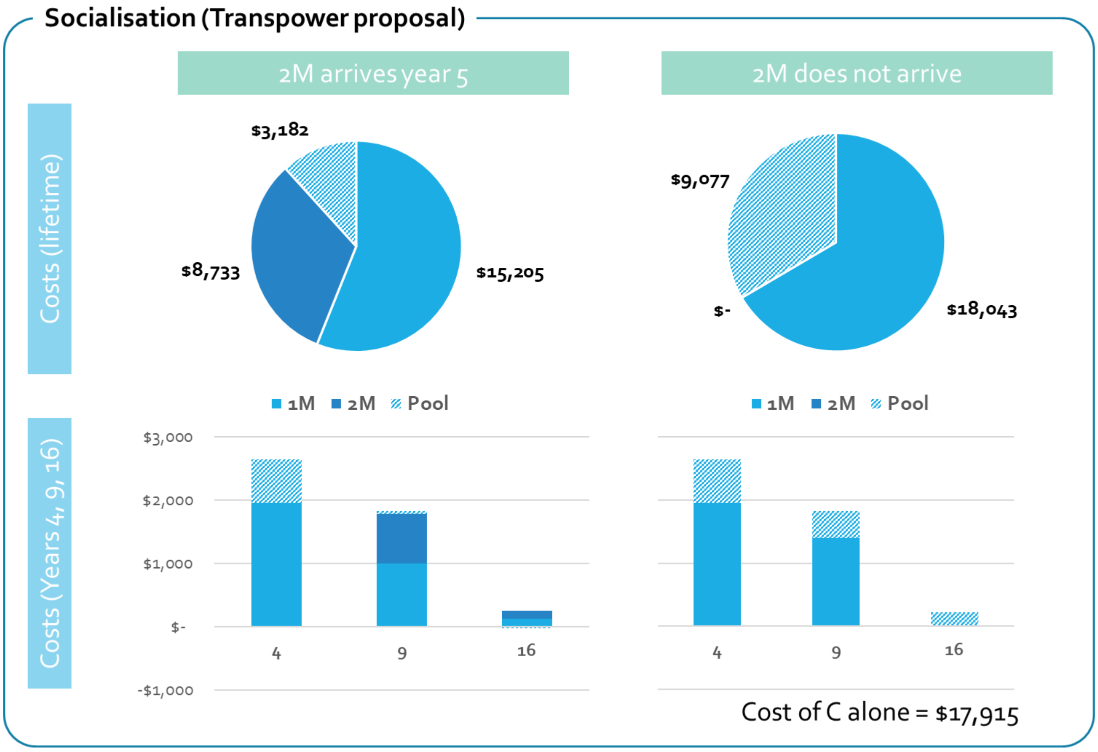
(b) overall, the first mover is similarly shielded from any downside risk and retains significant upside potential.[302]

Illustrating the pool and share (full socialisation) approach

E.20 The pool and share approach shown below recovers costs relating to anticipatory capacity from all connected customers in proportion to their connection capacity. The pooling and sharing would last until subsequent movers take up the anticipatory capacity.

302 The downside risk is that the first mover could pay more than the cost of C if X is built but unused, and the upside potential is that they pay less than the cost of C if they end up sharing the cost of C+X with other movers.

Figure 30 FMD allocations for the pool and share (full socialisation) option



E.21 Key observations for this method are:

(a) The net cost transferred to the connection pool declines each year as X ages.[303]

(b) If a second mover arrives, the first mover enjoys an immediate reduction in their charges, and costs are no longer transferred to the connection pool.

(c) If the second mover does not arrive, the first mover's charges are almost the same as if they had only contracted for C.

(d) Overall, the first mover is shielded from any downside risk and retains significant upside potential.

Illustrating the temporary socialisation approach

E.22 Temporary socialisation operates exactly as per Transpower's proposed pool and share approach except the first mover can only defer payments for X until they have finished paying for C, or the second mover has arrived to share the cost of C+X.

E.23 Under this option:

(a) The deferral period is capped at 10 years (the typical maximum duration of a NIC) and the cost of X is recorded in a tracking account.

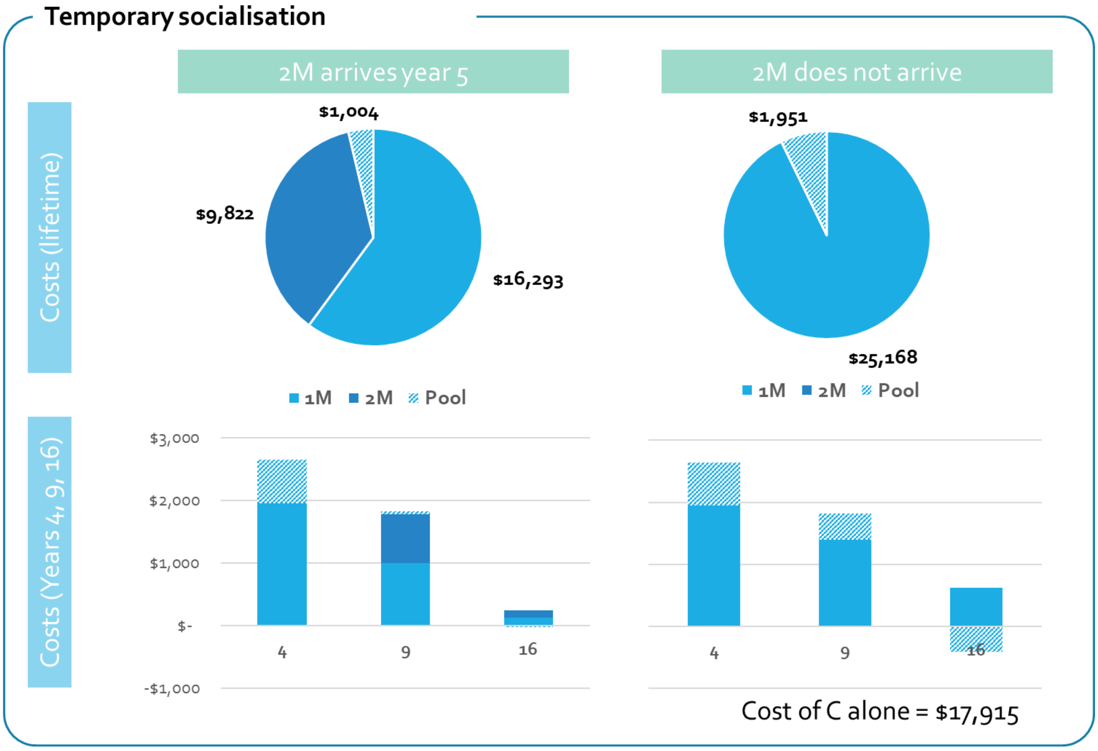
(b) The tracking account accrues interest, and is repaid over the same duration as the deferral period, (ie, up to 10 years).

(c) The first and second mover (if they have arrived) pay down the tracking account together.

303 See paragraph 4.9

E.24 Figure 31 illustrates how this option allocates the cost of C and X, using the same scenarios as the other illustrations.

Figure 31 FMD allocations for temporary socialisation option



E.25 Key observations for this approach are:

(a) If the second mover arrives:

(i) the first and second mover still enjoy lower costs by sharing C+X

(ii) some of the upside is used to repay to connection pool

(iii) the burden on the connection pool is much smaller than the other options[304]

(b) If the second mover does not arrive:

(i) most of the cost of X falls on the first mover and the burden on the connection pool is much smaller than the other options[305]

(ii) the first mover has extended (20 years) access to Transpower's low cost of financing for the cost of X

(c) Overall, the first mover has some exposure to downside risk and retains some upside potential.

304 It is not zero, because interest on the tracking account uses Transpower's financing rate, which we have assumed is lower than customer discount rates. In other words, customers see the repayments in years 6-15 as worth slightly less than the holding costs in year 1 to 5.

305 Again, the value is not zero. The figure is larger in this case because customers wait longer before receiving repayments (in years 11-20).

Appendix F BBC allocation: supporting information

F.1 This appendix provides supporting information for chapter 5, which covers benefit-based charge allocation under the proposed TPM. This information includes:

(a) further context on why both a default and an alternative allocation method are required for standard method investments with market benefits

(b) an example of a situation where an adjustment to prices could be appropriate under the price-quantity standard method

(c) charts illustrating the regional allocation of charges under the simple method.

Default and alternative methods for market benefits

F.2 This section sets out information provided by Transpower in response to an Authority request for information, to inform the Authority's assessment of the standard method. The Authority asked Transpower to explain why it considered the alternative (clause 53) method would not be appropriate for the CUWLP case study, focusing on practical difficulties.[306]

F.3 Transpower has advised that the clause 52 method removes some of the impact of uncertain and subjective input assumptions on the resulting allocations, by implicitly assuming an even price change either side of the constraint. Transpower considers there to be significant practical challenges with estimating market price changes over a 20-year analysis period.

F.4 Transpower's views are informed by its assessment of the appropriate generation assumptions to use for the CUWLP case study, as described in Transpower's Reasons paper, and paragraphs F.10 to F.15 (which illustrates when Transpower would likely adjust prices as provided for under clause 50(5).[307]

F.5 Transpower has advised there are number of factors (discussed below) that affect market price which Transpower does not model under clause 53 for practical reasons.[308] These limitations have supported Transpower's conclusion that clause 52 is the preferable method in those situations where Transpower considers it will result in allocations that are broadly proportional to benefits for a given benefit-based investment.

F.6 These limitations include the following:

F.7 A key assumption for the clause 53 method modelling is a perfectly competitive market (in the short run) with no market power.[309] Due to this assumption, market prices produced using clause 53 may not be an accurate reflection of real market prices (for some BBIs). For example, for the CUWLP investment, the disbenefit to lower South Island load of alleviating the export constraint

306 Sections 9.2 and 9.9 of Chapter 7 of Transpower's *Reasons* paper provide more information on Transpower's reasons for using clause 52 (noting that in the 30 June proposal this method was referred to as clause 50A method) where it leads to allocations that are broadly proportional to benefits.

307 See paragraphs 166-172 in Chapter 7 (BBC Allocations) and paragraphs 103-105 in Appendix D (BBC Price quantity method case study – CUWLP) in Transpower's *Reasons* paper.

308 See *Reasons* paper Appendix D paragraph 168.

309 This assumption is made because modelling market power would add discretionary assumptions to an already complex model, which would impact the certainty of the methodology and the cost to develop and comply with the proposed TPM. See clause 1(b) of the Guidelines.

depends on the extent to which LSI prices would be affected by market power (raising prices) at times when the export constraint binds.[310]

F.8 Modelled generation offers under clause 53 are likely to be significantly less granular and contain less variation from week to week than observed in the real world.[311] These simplifying assumptions are necessary for the modelling to be tractable. Generation offers are influenced by many factors, (eg, the market for fuel, contract structure, risk positions, etc). This data is impractical for Transpower to obtain as it differs for each generator and is subject to commercial sensitivities – and would be difficult to model.

F.9 Due to practical difficulties in obtaining information, generation outages were not modelled as occurring at different times throughout the year (as occurs in reality).[312] Instead, a constant de-rating to generation is applied to reflect outages. Further, transmission outages were not modelled for the purposes of the case study, due to the difficulty of modelling timing that may depend on the hydrological situation.

Adjustments to prices used in price-quantity standard method

F.10 This section describes a situation where an adjustment to prices under clause 50(5) could be required to ensure that allocations under the price-quantity standard method reflect benefits. The example illustrates why this discretion is included in the proposed TPM.[313] It was provided by Transpower in response to an Authority query, to inform our assessment of the standard method. We asked Transpower to explain how and when adjustments under clause 50(5) might be made under the clause 53 method.

F.11 Transpower notes that it envisages two situations in which it expects to make clause 50(5) adjustments to market price outputs of the wholesale market model under clause 53:

(h) to moderate the sensitivity of market price outputs to uncertain input assumptions

(i) to capture price changes that are not reflected in the market price outputs due to the modelling framework.

(a) moderate the sensitivity of market prices to uncertain input assumptions

F.12 The graph below shows the unadjusted time-weighted average market price in the North Island (in $/MWh) for the CUWLP case study ('Tiwai leaves' scenario).[314]

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310 If market power was a factor, prices upstream of the constraint would be higher than they would otherwise be, at times when the constraint binds.

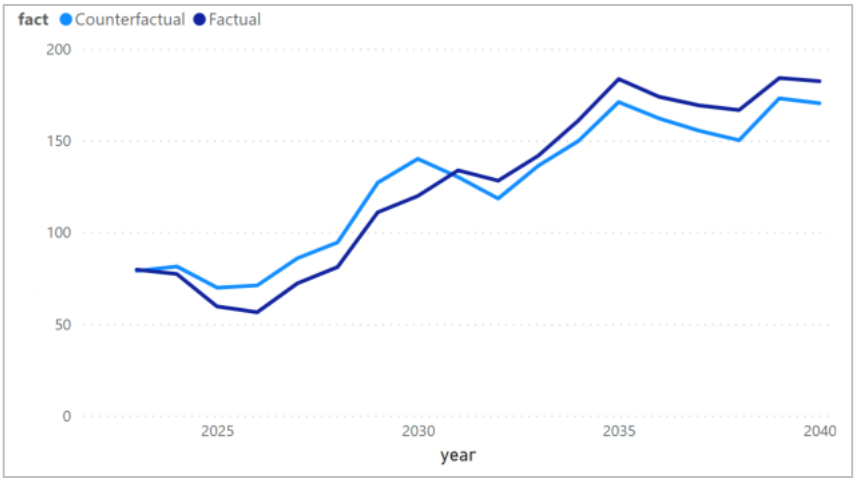
311 If Transpower were to apply clause 53 for CUWLP with the input assumptions it used in Appendix D of the *Reasons* paper, it would effectively have one offer tranche per week for each generator, when in reality there are up to 10 offer tranches for each of 48 trading periods during each day.

312 Transpower's *Reasons* paper, Appendix D.

313 Transpower explained its reasons for clause 50(5) in Transpower's *Reasons* paper, Chapter 7, para 128

314 Transpower does not propose to use the clause 53 method to allocate the costs of the CUWLP investment. Rather, it expects to use the clause 52 method for the CUWLP investment (and others like it). However, this modelling is provided as an illustrative example of the sensitivity of price outputs of the market model.

Figure 32 Time-weighted average price in the North Island – CUWLP case study, 'Tiwai leaves' scenario



Source: Transpower.

F.13 As expected, prices until 2030 are lower in the factual scenario in which the CUWLP investment is commissioned (dark blue line), compared to prices in the counterfactual scenario in which CUWLP is not commissioned (light blue line). This is due to the lower-cost generation released by the CUWLP investment removing the constraint.[315]

F.14 After 2030, however, the graph shows the unexpected result that prices would be lower in the counterfactual than in the factual for the rest of the analysis period. Transpower has advised that its view is that this would result in allocations that are not broadly proportional to expected positive net-private benefits – and that in a situation like this it would be appropriate to adjust prices using clause 50(5).

(b) capture price changes that are not reflected in the market price outputs due to the modelling framework

F.15 Transpower explains in its Reasons paper that in some situations the modelling framework may not produce market prices that are broadly proportional to benefits.[316] For example, without price adjustments, generators that are typically marginal may receive an allocation close to zero (because the modelling framework sets the price equal to the operational cost of the marginal generator). In reality, Transpower would expect prices to be above the operational cost of the marginal generator.

315 Transpower's *Reasons* paper, Appendix D, para 103.

316 Transpower's *Reasons* paper, Chapter 7, paras 46.2, 128, and 165.

Visualisation of simple method allocations

F.16 In this section we illustrate which customers (in which regions) will pay the costs of grid investment commissioned in a given region – when allocated under the simple method for allocation of the costs of low-value grid investments, (ie, below $20m).[317]

F.17 The allocators used in the simple method are a key input to simple method benefit-based charges. These allocators are based on a detailed assessment of historical energy flows over a 5-year measurement period.[318]

Charges paid by regional load beneficiaries

F.18 Approximately 50% of simple method charges will be allocated to load customers. The chart below shows for each $1 invested in an investment region (in the left-hand column) the portion of the load share (approximately 50 cents) that will be paid as charges by load customers in each beneficiary region (on the right).

(a) Darker blue colouring indicates charges paid within an investment region.

(b) Lighter blue indicates investments made in a high voltage (nominal voltage of 220kV or more) region and paid for by customers in low voltage (nominal voltage of less than 220kV) regions supplied from this high voltage region. Over this measurement period, electricity generally flowed from high voltage regions (where most generation is connected) to low voltage regions. Hence load customers in low voltage regions benefit from investments in the high voltage regions from which they are supplied.

(c) Pink colouring indicates any other charges not falling within (a) or (b) above.

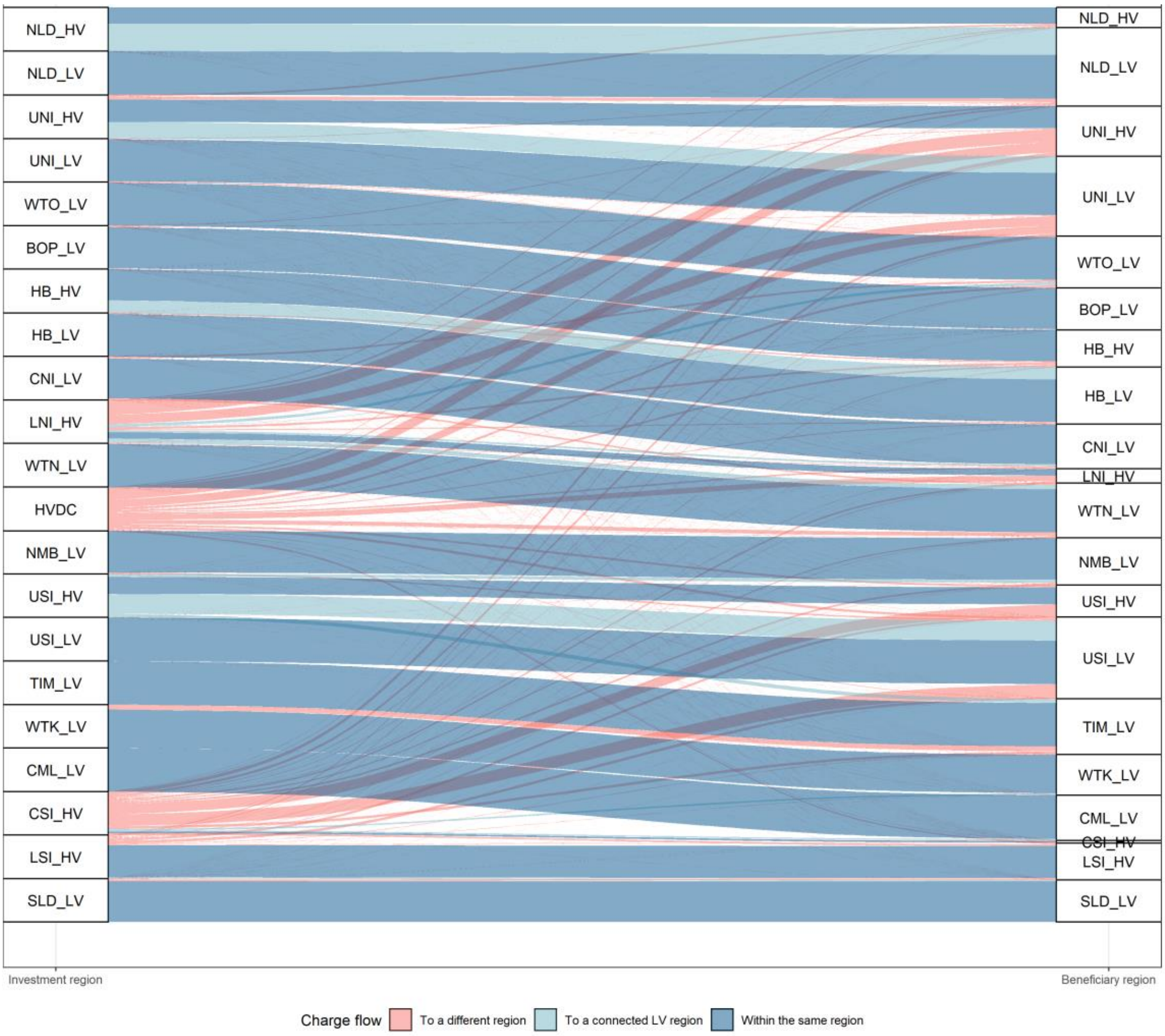
(d) If the height of the box for the beneficiary region (on the right) is larger than for the investment region of the same name (on the left) (eg, USI_LV), this indicates that load customers in these regions pay a larger proportion of investment costs due to also picking up a proportion of investment costs relating to investments in other regions. Note the relative size of each box is based on each $1 spent in each investment region and does not reflect the relative value of each beneficiary region's charge based on the total $ spend in each investment region.

(e) Conversely, if the height of the box for the beneficiary region (on the right) is smaller than for the investment region of the same name (on the left), (eg, LNI_HV), this indicates that a proportion of the investment costs in this region are paid for by load customers in other regions (as well as load customers in the same region).

317 The analysis uses information from Transpower's refreshed indicative pricing modelling from 15 September 2021.

318 For further information on the simple method refer to Transpower's *Reasons* paper, Chapter 7. The simple method allocations applied in the indicative pricing are provided in the spreadsheet 'Supporting Information for App B Simple BBI customer and regional allocations' prepared by Transpower and published alongside the Authority's proposal.

Figure 33 Charges paid by regional load beneficiaries



F.19 Some observations:

(a) The bulk of charges paid by load customers generally either are paid by customers within the same region as the investment (darker blue) or else are paid by customers in lower voltage regions supplied from the region (lighter blue). Given the nature of these investments (ie, relatively low value refurbishment and replacement investments to maintain the grid), it is intuitive that generally the main share of benefits of these investments (attributable to load customers) is attributed to customers in the same general geographical area.

(b) A significant portion of load charges relating to investment in generation-heavy regions, ie, LNI_HV and CSI_HV, is paid by customers in other regions (pink). This makes sense as generation in these generation-heavy regions clearly supplies load customers located in a broader geographical area.

(c) Similarly, HVDC charges also tend to be paid by customers in a wider geographical area, which is intuitive for such a core component of the grid.

Charges paid by regional generation beneficiaries

F.20 Approximately 50% of simple method charges will be allocated to generation customers. The chart below shows for each $1 invested in an investment region (in the left-hand column) the portion of the load share (50 cents) that will be paid as charges by generation customers in each beneficiary region (on the right).

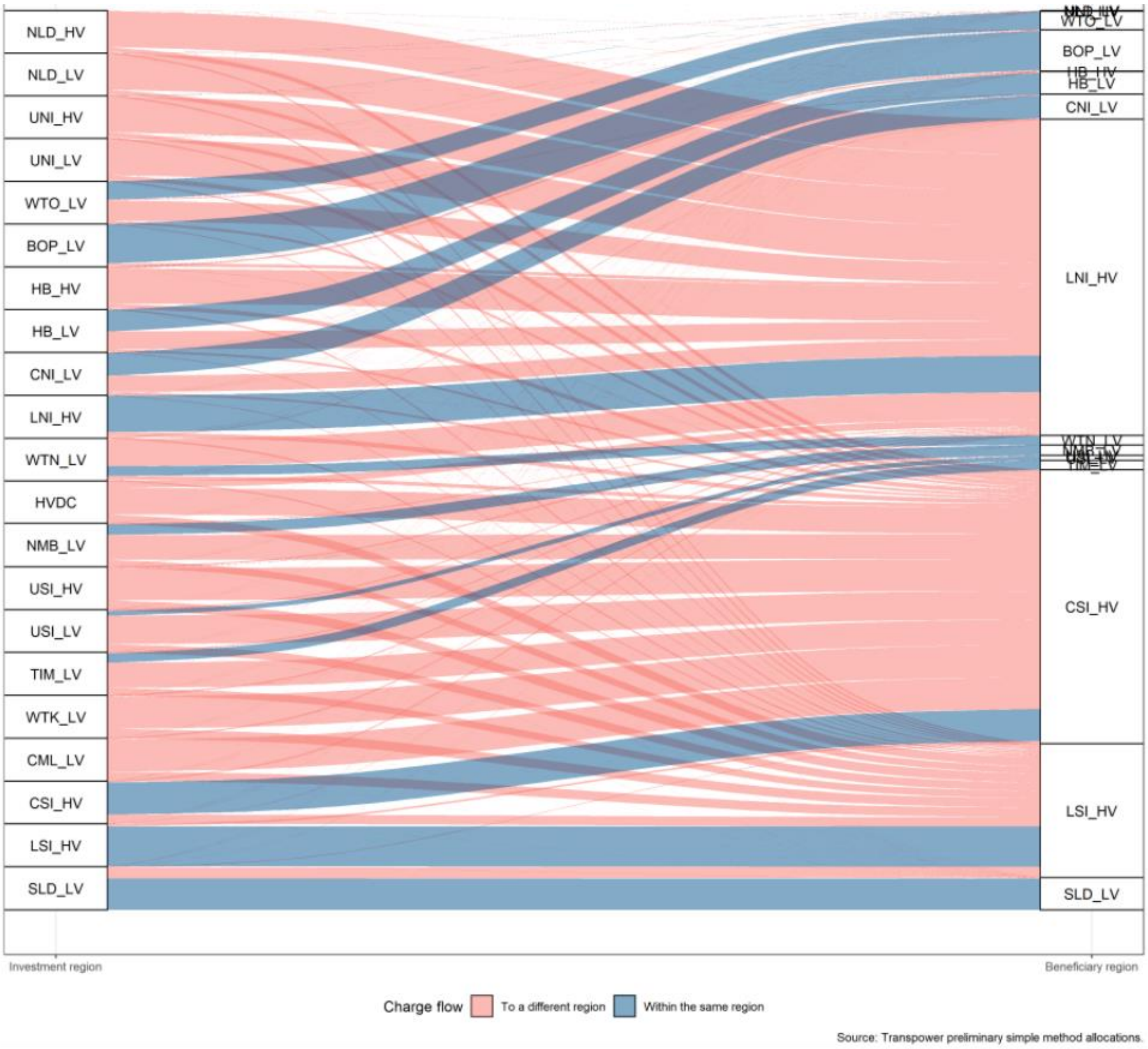
(a) Flows in blue indicate charges paid within an investment region.

(b) Flows in pink indicate charges paid by customers in other regions.

(c) If the height of the box for the beneficiary region (on the right) is larger than for the investment region of the same name (on the left), (eg, LSI_HV) this indicates that generation customers in these regions pay a larger proportion of investment costs due to picking up a proportion of investment costs relating to investments in other regions. Note the relative size of each box is based on each $1 spent in each investment region and does not reflect the relative value of each beneficiary region's charge based on the total $ spend in each investment region.

(d) Conversely, if the height of the box for the beneficiary region (on the right) is smaller than for the investment region of the same name (on the left), (eg, WTO_LV) this indicates that a proportion of the investment costs in these regions are paid by generation customers in other regions.

Figure 34 Charges paid by regional generation beneficiaries



F.21 Some observations:

(a) The majority of charges paid by generation customers are paid by customers in regions other than the one in which the investment was made (pink). This is because the majority of generation is located in three regions: LNI_HV, CSI_HV and LSI_HV. These regions export significant amounts of power to other regions.

(b) However, for regions where the generation and load are more closely matched, eg, BOP_LV, HB_LV, CNI_LV, SLD_LV, there are less imports into and exports out of the region. Hence the generation charges tend to be paid by customers within the same region as where the investment was made (blue).

F.22 The table below sets out regions’ names with the acronyms used in the charts.

Table 20 Simple method region names

Simple method region	Chart label
North Island	
Northland HV	NLD_HV
Northland LV	NLD_LV
Upper North Island HV	UNI_HV
Upper North Island LV	UNI_LV
Waikato LV	WTO_LV
Bay of Plenty LV	BOP_LV
Hawkes Bay HV	HB_HV
Hawkes Bay LV	HB_LV
Central North Island HV	CNI_LV
Lower North Island HV	LNI_HV
Wellington LV	WTN_LV
North and South Island	
HVDC	HVDC
South Island	
Nelson Marlborough LV	NMB_LV
Upper South Island HV	USI_HV
Upper South Island LV	USI_LV
Timaru LV	TIM_LV
Waitaki LV	WTK_LV
Cromwell LV	CML_LV
Central South Island HV	CSI_HV
Lower South Island HV	LSI_HV
Southland LV	SLD_LV

Appendix G Comparing indicative prices

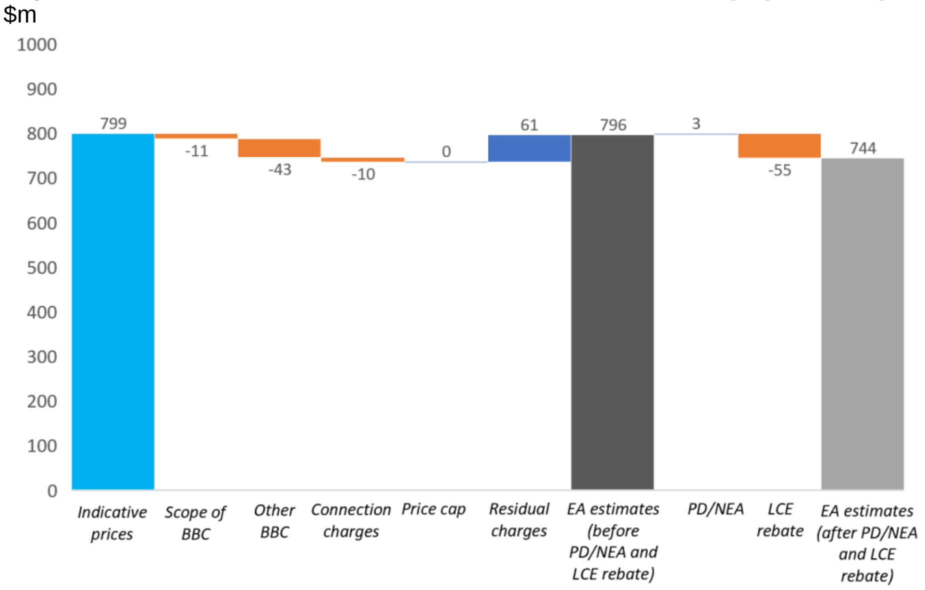
G.1 The indicative pricing for the proposed TPM differs from the Authority's estimates included in the 2020 Decision paper. Figure 35 shows this is primarily because:

(a) the Authority's 2020 estimates assumed a larger pool of residual charges payable by load customers only. Under the proposed TPM a higher share of revenue would be recovered through benefit-based charges

(b) the proposed design of the simple method in particular also means higher benefit-based charges for generators

(c) the estimates here do not adjust the level of customers' indicative prices to reflect the LCE rebate, as in the Authority's 2020 estimates. Note this would affect the level of but not materially the change in indicative prices.

Figure 35 Waterfall of differences between Decision paper and proposal



Difference	Discussion
Scope of BBC	The benefit-based charge component is $11m higher than the Authority's 2020 estimates, and residual charges are correspondingly lower. In addition to Schedule 1 investments, the BBCs in the indicative pricing include the cost of simple method investments for pricing year 2021/22 ($11m). The Authority's 2020 BBC estimates only included Schedule 1 investments.
Other BBC	BBCs reflect updated current business information and specific aspects of the proposed TPM (eg, overhead opex allocation). As a result, indicative BBCs are $43m higher, and residual charges lower, than the Authority's 2020 estimates.
Connection charges	Actual 2021/22 connection charges are $10m higher (and so residual charges lower) than in the Authority's 2020 estimate based on Transpower's disclosed information.[319]
Price cap	The net impact of applying the price cap is zero. In the proposed TPM the price cap redistributes $2.3m less compared with the Authority's 2020 estimates.

319 Note also that connection charges were not included in tables in 2020 Decision paper, as the Guidelines did not change materially.

Difference	Discussion
Residual charges	Due to the above factors, residual charges in the indicative pricing are $61m lower than the Authority’s 2020 estimates.
Prudent discounts / notional embedding agreements	Current prudent discount agreements (Waipori, Aniwhenua/Matahina) and a notional embedding contract (BlackPoint) are assumed not to carry into the proposed TPM given the different basis for charges. Authority 2020 estimates assumed value of $3m.
LCE rebate	Indicative prices are not adjusted for LCE rebates. This reflects that indicative prices recover the maximum allowable revenue determined by the Commerce Commission. The Authority’s 2020 estimates did adjust for the LCE rebate, to recognise that customers receive an LCE rebate in proportion to their transmission charges.

Glossary of abbreviations and terms

ACOT	Avoided cost of transmission
Act	Electricity Industry Act 2010
AHC	Average Historic Cost
AMD	Anytime maximum demand
Authority	Electricity Authority
Capex IM	Capital expenditure input methodology
CBA	Cost-benefit analysis
CIC	Customer investment contract
Code	Electricity Industry Participation Code 2010
DER	Distributed energy resources
DGPP	Distributed generation pricing principles
DHC	Depreciated Historical Cost
DME framework	TPM decision-making and economic framework
EDB	Electricity distribution business or businesses
ENA	Electricity Networks Association
FTR	Financial transmission rights
GWh	Gigawatt hour
HVDC	High voltage direct current
ICP	Installation control point
IM	Input methodology
IPP	Individual price path
kWh	Kilowatt hour
kvar	Kilovolt ampere reactive
LCE	Loss and constraint excess
LMP	Locational marginal price or pricing
LNI	Lower North Island
LRMC	Long-run marginal cost
LSI	Lower South Island
MAR	Maximum allowable revenue
MW	Megawatt

MWh	Megawatt hour
NAaN	North Auckland and Northland grid upgrade project
NIGU	North Island Grid Upgrade Project
NZAS	New Zealand Aluminium Smelters
PDP	Prudent discount policy
RAB	Regulatory asset base
RCP	Regulatory control period
RCPD	Regional coincident peak demand
RTP	Real time prices or pricing
SIMI	South Island mean injections
SPD	Scheduling, pricing and dispatch model
SRMC	Short-run marginal cost
TPAG	Transmission Pricing Advisory Group
TPM	Transmission Pricing Methodology
Transpower	Transpower New Zealand Limited
UNI	Upper North Island
USI	Upper South Island
VoLL	Value of lost load
VPO	Virtual price offer
vSPD	Vectorised Scheduling, pricing and dispatch model