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01 October 2019

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By email: submissions@ea.govt.nz

Dear James

Submission: Transmission pricing review 2019 issues paper

Transpower appreciates the opportunity to submit on the Electricity Authority's (**Authority's**) transmission pricing review 2019 issues paper.

As the Authority will be aware, the transmission pricing methodology (**TPM**) debate is now well into its second decade. The Authority's own transmission pricing review began more than seven years ago. There is widespread agreement that a timely and workable solution to the TPM debate is needed to give all market participants certainty and confidence in the TPM framework. This is particularly the case for those parties poised to make investments that will help the country achieve its climate change ambitions through electrification and renewable generation.

We have valued the opportunity to hear from the Authority's team and other stakeholders at the workshops held during the consultation period. We support the Authority's decision to seek cross-submissions. The Authority has also indicated it may include a conference as part of the final stages of its review. We strongly support the addition of this step, particularly given it has been more than six years since the conference held in relation to the first issues paper.

Executive summary

We acknowledge that there are significant elements of the TPM that require review and we are supportive of the need for the Authority to move quickly on these. We note that the positions in the Authority's current proposal are consistent at a high level with the Authority's earlier transmission pricing review proposals. While our stance on these points is largely unchanged,[1] we consider that it is important to restate our view that the Authority's current TPM proposal runs a risk of not being in consumers' best interests and may not meet the Authority's statutory objective of delivering significant long-term benefits to consumers. Moreover, we are concerned that the proposal may not support New Zealand's transition to a low-emissions economy.

We are supportive of a measured approach to amending the TPM and Transpower is appreciative of the extensive work the Authority has conducted in identifying a number of significant issues that

[1] Our positions on the Authority's earlier transmission pricing review proposals are summarised in **Appendix 2**.

require review. In our view, extensive reform of the sort proposed by the Authority may not be the most effective or efficient manner to address TPM concerns. We consider that the concerns with the TPM may be more effectively and efficiently addressed through measured and incremental reform of the existing methodology. This would have the benefit of bringing the reforms to the market more quickly with a substantially lower risk of unintended consequences. Our submission proffers some practical options for such reform.

In the event that the Authority's proposal was to be implemented, then we consider that there are some workability issues in the drafting of the proposed new TPM guidelines (**Guidelines**) that would benefit from further review.

Introduction

The Authority is proposing to introduce new Guidelines designed to deliver a paradigm shift in transmission pricing, based broadly on a concept of beneficiaries-pay through fixed charges. As noted above, where the positions in the Authority's current proposal are consistent with its earlier transmission pricing review proposals, our stance on these points is largely unchanged. However, as the issues around climate change have advanced at pace since the TPM process began, we have recharacterised and amplified our position on the criticality of acknowledging the importance of the government's climate change goals in setting the TPM for the future. We submit that our position on the TPM being responsive to climate change issues is consistent with and supportive of the Authority's statutory objective.

We are financially neutral to the pricing outcome of the TPM review, since our overall revenue requirement is determined by the Commerce Commission through a separate regulatory process. Accordingly, we consider that we are well placed to provide a balanced, impartial, and informed commentary on the Authority's proposal. This is reinforced by our position at the centre of TPM development, implementation and ongoing operation.

In our view it is important for the TPM and Guidelines to:

- support timely, efficient transmission investment via the Commerce Commission's processes;
- limit the risk of unintended consequences (including of inadvertently undermining New Zealand's efforts to respond to climate change);
- be workable, practicable and understandable to our customers and stakeholders; and
- limit the risk of legal challenges to transmission pricing decisions by being objective and fair.

When considered in context and against the counterfactual, it is not clear to us that the Authority's TPM proposal is consistent with these requirements. We elaborate on these points in the remainder of this submission.

We provide our views on how the problems with the current TPM identified by the Authority could be addressed more quickly through incremental reform of the current TPM and Guidelines. We also submit that changes to the Authority's proposal would improve its workability and address some of its potential, predictable, and unintended consequences.

Our submission comprises this letter and the following supporting information:

Appendix 1:	Options for incremental TPM reform
Appendix 2:	Transpower's positions on the Authority's transmission pricing review
Appendix 3:	Case Studies – application of benefit-based charging
Appendix 4:	Analysis of the proposed price cap

Attachment A:	Axiom Economics - Economic review of transmission pricing review consultation paper
Attachment B:	Clause-by-clause commentary on proposed TPM Guidelines
Attachment C:	Answers to the Authority's questions in the 2019 Issues Paper.

Transmission pricing needs to support climate change response

The Authority states on its website that:

> *We consider [our] proposal would deliver significant benefits to consumers in the long-term, and support the transition to a low-emissions economy at the least cost to consumers.*[2]

The Authority considers its cost-benefit analysis (**CBA**) supports a conclusion that its proposed approach to transmission pricing would promote the efficient operation of the electricity industry for the long-term benefit of consumers. To inform our submission on this premise we commissioned an expert review of the CBA from Axiom Economics (**Axiom**).[3]

Axiom concluded that the CBA cannot safely be taken at face value. Axiom considers that correcting two of the more serious errors in the Authority's CBA would turn the estimated net benefit into a substantial net cost. If the CBA was to be taken at face value, the modelling concludes that the proposal may not deliver a material net benefit for 12 years. However, the modelling also expects there to be a significant "political uncertainty event" within 11 years, which could take the form of another substantial change to the TPM.[4] In other words, the Authority's CBA suggests the proposed TPM reform might deliver no net benefit for eleven years before it is itself supplanted by another reform.

We consider such a material change in approach to transmission pricing should be supported by a CBA that achieves a high level of acceptance from the experts who review it. We are therefore interested to hear the opinion of experts commissioned by other submitters, and from the Authority as to its confidence in how its proposal would benefit consumers over these timeframes. We repeat our recommendation that these views could be effectively and efficiently tested through an industry-wide conference.

There is a broad and growing consensus within New Zealand and throughout the world that urgent and substantial action is needed to combat climate change. To that end, in October 2018 we outlined our view to the Electricity Price Review panel (**EPR**),[5] noting the government's priorities of a pathway to our climate change goals required also addressing energy affordability and hardship. We stated that the country's 2050 goals require significant change in the sector and the economy, and establishing and maintaining a public consensus is needed to ensure the energy sector is working for all New Zealanders. In the year that has elapsed since we raised these views to the EPR, the need for profound movement on climate change, and renewable energy as an enabler, has only become more urgent.

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2 https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/

3 Axiom Economics is an independent economic consulting firm that specialises in the provision of expert and strategic advice on competition, economic regulation, third party access, commercial disputes and policy issues. We commissioned Axiom Economics to review the 2019 issues paper and cost-benefit analysis. Axiom's report is in **Attachment A**.

4 The Authority's 'top-down' modelling of "uncertainty benefits" reveals that it expects there to be a significant "political uncertainty event" within 11 years. Refer to CBA technical paper page 90

5 Transpower submission to the Electricity Price Review's First Report, 23 October 2018

Our *Te Mauri Hiko – Energy Futures* work explained why decarbonisation depends on expanding our renewable electricity base and our ability to electrify new parts of the economy, such as transport and process heat.[6] We have predicted that electricity demand in New Zealand will grow significantly from 2020 and may double by 2050, as consumers invest in electric vehicles and other emerging technologies. The effectiveness with which we manage this transition will play a decisive role in meeting New Zealand's climate change objectives and commitments; the TPM has a significant role to play in the transition to a decarbonised economy.

The key *Te Mauri Hiko* messages and modelling have strong convergence with the Productivity Commission's '*Low-emissions economy' report*'.[7] More recently, the Interim Climate Change Committee's '*Electricity inquiry - Final Report'* reinforced the importance of electrification to New Zealand's climate change response. It recommended taking action to reduce greenhouse gas emissions in the sector.[8] The report contained the stark warning that "continued delay is not an option". We concur with that assessment.

We are working to understand how we can ensure our business will keep pace with the new grid connections needed to enable electrification. These new connections could give rise to a need for new interconnections that relieve constraints and unlock grid capacity. Our project, "Enabling New Connections" is considering what Transpower and the industry needs to do to ensure timely, efficient grid investment can support New Zealand to meet our significant decarbonisation challenge. We must be confident we can provide clear and understandable pricing information to support those investment decisions.

Importantly, we do not consider the Authority's transmission pricing proposal, in its current form, would assist in unlocking renewable energy resources.[9] It appears, from our analysis relative to the current TPM, that it is more likely to have the contrary objective of putting the much-needed transition to a low-emissions future in question. Key aspects of the proposed methodology are, in our view, more likely to disincentivise electrification and deter or delay greenhouse gas emissions reductions across the economy. In this respect, the proposal may be inconsistent with New Zealand's broader energy policy framework.

Our key points

- **The Authority's proposal may not support New Zealand's climate change response:** Our analysis indicates that the Authority's proposal may consciously encourage additional consumption during peak periods. This is likely to put upward pressure on wholesale prices and cause more investment in gas-fired peaking generation, the transmission network and distribution networks. The net result would be higher electricity prices and elevated greenhouse gas emissions. This would exacerbate energy affordability problems and compromise the achievement of climate change objectives.[10]

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6 Transpower Te Mauri Hiko – Energy Futures, June 2018. See also our latest quarterly update.

7 NZ Productivity Commission Low Emissions Economy - Final report, August 2018. Te Mauri Hiko reported a doubling of electricity demand, the Productivity Commission more than 1.5 times.

8 Interim Climate Change Committee, Electricity Inquiry – Final report, April 2019.

9 While any review of the TPM provides an opportunity to address the 'first mover disadvantage' under the connection charge, we consider the solutions could be accommodated with change under the policy framework of the current Guidelines (we need the opportunity to consult on and propose changes to the TPM itself).

10 The Authority has stated that addressing climate change is not part of the its statutory objective. However, in our view, this is an unnecessarily narrow interpretation of the objective. We consider that the long-term effectiveness of the Guidelines and the TPM are a key component to achievement of the Government's clearly signalled policy in this area and it is critical that the TPM and future-focussed policy are aligned.

- **The Authority's proposal would put timely, efficient grid investment at risk:** The Authority concludes that introducing the proposed 'benefits-based' (**BB**) charge would have a significant and beneficial impact upon the Commerce Commission's grid investment approval processes, resulting in more efficient expenditure. We find it difficult to agree with the Authority's analysis and submit that it is, instead, more likely to create sources of dispute and may incentivise parties to withhold information rather than share it. Where disputes over price outcomes hinder timely, efficient investment in transmission and generation, higher electricity prices (a disbenefit to consumers) and elevated greenhouse gas emissions are likely consequences.

- **The Authority's proposal would not ensure those who benefit pay for transmission investment in the longer term:** Customers' BB charges would be based on the benefits that Transpower estimates they will receive over the life of an investment at the time that it is made (or at the commencement of the new TPM in the case of the historical investments). Actual benefits will diverge from estimated benefits over time – perhaps dramatically. Moreover, the initial allocations would also apply to any upgrades made many years later.[11] It is hard to see how such a regime could be durable – a problem the Authority itself acknowledged in its first issues paper.[12] To illustrate some of the challenges with the proposed BB charges we have provided in **Appendix 3** some simplified case studies of how the charge might apply to (hypothetical) grid investment.

- **A peak price signal is needed for an efficient TPM:** The Authority's proposal appears to be unsympathetic towards retaining a peak pricing signal in the TPM. We submit that a peak price signal for transmission saves consumers money by deferring new transmission investment. Real-time nodal energy prices cannot do this job – as the Authority has acknowledged in the past.[13] Opportunities to incentivise peak-demand management through the design of transmission charges should not be passed up in favour of more expensive alternatives, such as paying for demand response as a transmission alternative or through the wholesale energy market. We are firmly of the view that permanent peak pricing in the TPM is vital, particularly to support the electricity industry's climate change response.

- **Independent analysis suggests the Authority's CBA may not support its proposal:** The Authority's CBA suggests benefits more than 10 times the level previously forecast for (materially) the same proposal. We find this difficult to reconcile. Axiom has independently confirmed that our reservations have foundation. In Axiom's assessment, the latest CBA suffers from methodological problems – many of them similar to those that resulted in the previous two CBAs being abandoned. In Axiom's view, the CBA has limited probative value.

- **The Authority's proposal has no international precedent:** The Authority's proposal does not, in our analysis, accord with international precedent and appears to have been heavily influenced by the opinion of one international expert in electricity market design. By contrast, the contrary perspectives offered by several other equally well-qualified international experts preferring a more orthodox approach do not appear to have found favour in the Authority's evaluation.

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[11] The Authority has also stated that decommissioned plant should still attract transmission charges as if it still existed (see the Authority's answer to Contact Energy Limited's question about exit and entry of generation assets). This is a difficult position to understand or justify to our customers.

[12] Electricity Authority, Transmission Pricing Methodology: issues and proposal, Consultation Paper, 10 October 2012, p.105.

[13] See for example: Electricity Authority, Transmission Pricing Review, TPM options, Working paper, 16 June 2015, p.53; and Electricity Authority, Transmission Pricing Review, LRMC charges, Working paper, 29 July 2014, p.29-30.

- **Problems with the TPM could be addressed through incremental reform:** The Authority has identified some problems with the current TPM with which we agree.[14] However, in our view, the problems could be dealt with more quickly, more effectively and more efficiently than extensive reforms, with less risk and at a lower cost by incrementally reforming the existing TPM and Guidelines. This approach would also carry a lower risk of unintended consequences and bring the reforms to the market in a more timely manner.

- **The Authority's proposed price cap would not prevent price shocks or smooth the transition:** We support the inclusion of transition provisions in the Guidelines. However, our review suggests the design of the proposed price cap would neither prevent price shocks for our customers nor limit consumers' electricity price increases to (initially) 3.5% as intended. The cap would also have the unusual consequence of increasing the price rises that most load customers would otherwise face in its absence.[15]

- **The Authority's proposed TPM development process may not give us enough time to engage with our stakeholders:** In our view, allowing Transpower enough time to do a good job of developing any new TPM, including strong engagement with our stakeholders, would save time and work in the end. In our view 18 months to submit a new TPM is ambitious, any less introduces a very high level of risk to our ability to deliver a durable TPM proposal to the Authority. We would be more comfortable with 24 months.

- **Transpower needs certainty of cost-recovery ahead of time:** Finding an appropriate way for Transpower to recover its costs of TPM development, implementation and ongoing operation remains a pressing issue. Certainty ahead of time would allow us to better prepare to develop any new TPM within a reasonable timeline. We look forward to continuing to work with the Authority and Commerce Commission to resolve this matter.

- **There are workability issues in the proposed Guidelines:** The 2019 Issues Paper draft Guidelines are a significantly better and more workable than the 2016 version. Should the Authority proceed with its proposal there remain workability challenges. We provide our commentary on these in **Attachment B**. It would be prudent to undertake a 'technical drafting' consultation once the Authority has made any final decision to replace or amend the TPM Guidelines.

We expand on these key points below.

The Authority's proposal may not support New Zealand's climate change response

The Authority has stated that addressing climate change is not part of its statutory objective.[16] We consider this is an unnecessarily narrow interpretation of Section 15 of the Electricity Industry Act 2010 and does not take into account the importance climate change and the reduction of greenhouse gas emissions have in assessing the long-term benefit of consumers. We think that it would be incongruous for the Authority to implement a methodology that would undermine New

[14] The table in **Appendix 1** provides some examples of incremental reforms that could address some of the problems the Authority has identified with the current TPM.

[15] Price caps normally work by delaying price reductions that customers would otherwise be facing in its absence. We provide some analysis of the price cap mechanism proposed by the Authority in **Appendix 4**.

[16] Electricity Authority, Interpretation of the Authority's statutory objective, February 2011, clause A.67(b). "efficient operation of the electricity industry is interpreted within the context of other Government legislation and regulation affecting the electricity industry, and in particular does not allow consideration of pan-industry externalities such as carbon emissions"

Zealand's broader energy policy objectives. In our view, the Authority's TPM proposal has a non-trivial risk of doing so, and may be detrimental to the long-term benefit of consumers by:

- the proposal consciously – and deliberately – encouraging additional consumption during peak periods, while removing the only explicit forward-looking price signal from the TPM; and
- putting upward pressure on wholesale prices and causing more investment in gas-fired peaking generation, the transmission network and distribution networks – since these are natural consequences of higher peak demand.

The net result is likely to be higher overall electricity prices and elevated greenhouse gas emissions – a double-blow for the New Zealand economy. Specifically, the proposal would exacerbate the well-documented energy affordability problems that are afflicting too many consumers and compromise the achievement of broader climate change objectives.

This potential impact of the Authority's proposal on New Zealand's greenhouse gas emissions should be discussed among stakeholders and other policy makers. Many parties are working hard to achieve a low-emissions economy. In our view, it is imperative that these effects are considered properly before any TPM-related policy changes are made.

The Authority's proposal would put timely, efficient grid investment at risk

We are unable to agree with the Authority that introducing BB charges would have a significant and beneficial impact upon the Commerce Commission's grid investment approval processes, resulting in more efficient expenditure. It is, instead, more likely to result in the proceedings getting bogged down in private interests and disputes at the expense of security, reliability and wider economic and social wellbeing considerations (including responding to climate change). We note Axiom's view that:

> *if the proposal has any effect on the grid investment approval process, it is likely to be negative, since it would create more sources of dispute and generate incentives for parties to strategically withhold information.*

Consequently, we do not find support for the large benefit ($77m) the CBA attributes to the Authority's proposal encouraging greater scrutiny of grid investments. For the reasons set out above (and in more detail in Axiom's report), there is no reason to think there would be any such benefits in principle. Moreover, as Axiom explains, the specific methodology the Authority has used to derive the benefit estimate would appear to be flawed.

The Authority's proposal would not ensure those who benefit pay for transmission investment in the longer term

If the Authority's proposal was implemented, Transpower would be required to allocate BB charges to customers based on our estimates of the benefits they will receive over the life of an investment at the time that it is made.[17] Our customers' collective utilisation of the grid is constantly changing, and over time that change can be fundamental to what benefits (or disbenefits) are realised by individual customers. Inevitably, any forecast of benefits that will arise over several decades will be wrong. In our considered view, the probability of the benefits estimates proving to be right, or materially right, over the 30 to 50 year life of an interconnected grid investment is low.

For example, it is relatively easy to deduce that upper North Island consumers would be 'immediate' beneficiaries from our proposed Waikato and Upper North Island Voltage Management project. However, once we start to get more granular and look further into the future, things get more complex. For instance, it is very challenging to forecast how the relative benefits of the investment

[17] Or at the commencement of the new TPM in the case of the historical investments.

would accrue between consumers in Top Energy's network relative to consumers in Vector's network, say, ten or twenty years from now.

This is not a reason to never change the TPM. Rather, it is a reason to ensure the TPM can adapt in response to change. BB charges can be designed to adapt. For example, adopting a method consistent with that applied in the United States (**US**) would go some way to achieving this. There, charges are fixed ahead of time to large beneficiary zones and then on-charged to individual parties (in the US context these are generally transmission owners) who themselves on-charge using traditional tariff structures, including peak charges.[18] A similar approach in New Zealand would, in our view, significantly improve the chances of a successful move to BB charging.

To illustrate some of the problems and challenges with the Authority's proposed BB charges, we have included in **Appendix 3** some case studies for how the charge might apply to an upgrade of our transmission line between Wairakei and Hawke's Bay (hypothetically).

In our view, the alternative approach reflecting US precedent we have recommended above is likely to prove more workable and reasonably durable. In contrast, a highly granular approach that sought to lock-in charges and seldom – if ever – revisit them would have very little chance of being sustainable in the long-term. The Authority conceded as much in its first issues paper.[19]

A peak price signal is needed for an efficient TPM

We agree with the Authority there might be benefits to be obtained from reforming the current (RCPD) peak pricing signal in some way, (such as 'weakening' the strength of the signal and/or making it more targeted). However, our analysis strongly reinforces our belief that the long-term risks associated with removing entirely all peak price signalling from the TPM far outweigh any potential near-term benefits. We believe that dynamic efficiency benefits from peak-pricing outweigh any allocative efficiency benefits from their removal. Put another way, the potential long-term economic costs from having a peak signal that is 'too weak' outweigh the near-term costs associated with a signal that is 'too strong'.[20]

We also do not accept the Authority's claim that nodal prices alone can result in efficient short-term grid usage decisions *and* the right long-term investment outcomes, thereby obviating the need for a peak price signal in the TPM. This contention is not only at odds with widely accepted economic theory (as Axiom details in its report), it is also inconsistent with what the Authority has said in the past (when it supported unambiguously the economically orthodox position)[21] and what it continues to say in the context of distribution pricing (where it is encouraging peak pricing).[22]

Even if there are some parts of the grid with excess capacity at present, it does not follow that all peak pricing signals should be removed permanently. We would be open to modifying the existing signal. But removing it in all locations would, in time, spur peak demand growth and bring forward

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18 Joint report: Electricity Authority, Commerce Commission and Transpower, Beneficiaries-pay in USA: Discussions on implementation of beneficiaries-pay cost allocation for transmission investment, 20 June 2018 – page iii.

19 Electricity Authority, Transmission Pricing Methodology: issues and proposal, Consultation Paper, 10 October 2012, p.105.

20 The role of peak pricing for transmission (Transpower, November 2018).

21 See for example: Electricity Authority, Transmission Pricing Review, TPM options, Working paper, 16 June 2015, p.53; and Electricity Authority, Transmission Pricing Review, LRMC charges, Working paper, 29 July 2014, p.29-30.

22 See for example: Electricity Authority, More efficient distribution network pricing – principles and practice Decision paper, 4 June 2019, p.iii.

generation, distribution and transmission investment costs. Without a peak signal, we would not be able to efficiently defer those costs, or the increased greenhouse gas emissions that they would bring. We therefore remain of the view that permanent peak pricing in the TPM is vital, particularly to support the electricity industry's climate change response.

Independent analysis suggests the Authority's CBA may not support its proposal

Axiom's view is that the CBA is compromised, including for the following reasons:

- Neither the grid use model (which generates 96% of the estimated net benefits) nor the top-down modelling reflect the Authority's proposal.
- The net benefit estimate mistakenly includes $2.3b in bare wealth transfers that are neither benefits to New Zealand's economy nor improvements to the overall efficiency of the electricity industry. The analysis also ignores a $1.9b cost of additional investment that is estimated to be needed to produce the modelled benefits. Addressing these errors alone reduces the Authority's net benefit estimate to *negative* $1.5b.
- The modelling rests on assumptions that do not reflect the ways in which the electricity market works, or market participants act.
- Aspects of the modelling hinge crucially on assumptions and inputs that are arbitrary or lack objective foundation.

Axiom concludes that the CBA has no probative value and lends no support to the Authority's proposal.

Problems with the TPM could be addressed through incremental reform

The table in **Appendix 1** provides some examples of incremental reform options that could address the problems the Authority has identified with the current TPM.

In our view, this type of reform has significant advantages over the "root and branch" type reform of the Authority's proposal. It is faster and less expensive to implement, bringing the reforms to the market more quickly, and there is a lower risk of unintended consequences.

The Authority has previously noted (most recently in response to the EPR's hedge market reform proposals) that major regulatory changes carry a risk of unintended consequences and should be approached cautiously. For example, in the context of the Authority's proposal, there is a risk that the BB charge could inefficiently distort the wholesale electricity market and generation investment decisions. One concern we have is that the BB charge would send a signal to delay potential new generation until spot prices are not only high enough to cover the cost of the generation but also the new, and potentially uncertain, transmission charges. This would create windfalls (higher price benefits) for generators operating in areas that are subject to lower BB charges.

The Authority's proposed price cap would not prevent price shock or smooth the transition

The proposed price cap is not effective because it does not apply to all transmission charges. This means the price cap would not prevent price shocks. We provide, for clarity, some analysis of the proposed price cap mechanism in **Appendix 4**.

The Authority predicts that some of our distributor customers would face transmission charges increases of 100% or more and predicts large percentage increases for most of our direct-connect industrial customers. [23]

[23] Electricity Authority TPM review 2019 Issues Paper Table 12.

The Commerce Commission tends to cap regulated price increases at between 5% and 10% to fulfil its statutory obligation to minimise undue financial hardship for suppliers and price shocks for consumers. Most of our customers who are predicted to face increases in their transmission charges would incur increases far in excess of 10%.

The choice to base the price cap on a percentage (3.5% initially) of the total consumer bill would not have the effect of capping increases in consumers' bills at that percentage, not only because the price cap does not apply to all transmission charges but also because the TPM does not control how distributors pass transmission costs onto their customers. The total consumer bill approach also introduces complexity and estimation error into the calculation.

Another choice, to use transmission charges for the 19/20 pricing year as the comparator for the price cap regardless of when any new TPM takes effect in prices, means the year-to-year price impact on our customers would be different to the indicative effect modelled by the Authority.[24]

We submit that a better approach would be to apply the cap to all transmission charges and base the cap on a percentage of final year of transmission charges under the current TPM. Alternatively, the new transmission charges could be phased in in combination with the existing ones, similar to the transition from HAMI to SIMI for the current HVDC charge.

Process concerns – Timeframe and cost-recovery

Should the Authority proceed with its proposed new approach to transmission pricing, proper engagement with our stakeholders during TPM development would be critical to producing the most durable TPM possible within the constraints of the Guidelines. Constructive and highly engaged stakeholder participation would be key to achieving a successful development and implementation of any new TPM.

In our view 18 months to submit a new TPM consistent with the Authority's 2019 proposal, would be an ambitious and very challenging timeframe. Any less time introduces a very high level of risk to our ability to deliver a durable TPM proposal to the Authority. For reasons we have stated previously, we would be more comfortable with 24 months.

There remains uncertainty about how we would recover our costs of TPM development, implementation and ongoing operation, should the Authority decide to issue new Guidelines. Certainty about this early in the process would support our ability to develop the new TPM in a suitable timeframe.

Comments on draft Guidelines

We have challenged ourselves to consider afresh how we could make the Authority's proposal work. A significant focus of our review of the Authority's proposal has been on the draft Guidelines and what changes to these would be needed if the Authority were to adopt its current proposal.
We have identified a number of drafting and workability issues in the draft Guidelines that need to be resolved. These are highlighted in our clause-by-clause comments on the Guidelines in **Attachment B**. We would welcome the opportunity to work through these issues with the Authority and other stakeholders. Some of the issues remain from previous drafts of the Guidelines.

[24] The Authority's modelling assumes the new TPM to take effect in prices from April 2021, which would require a new TPM to be approved in time for Transpower's 2020 pricing round, commencing July 2020. Chapter 6 of the Authority's 2019 Issues Papers contemplates a new TPM taking effect from April 2024. We consider this outcome is more plausible.

In our view it would be prudent for the Authority to undertake a technical drafting consultation once it has made final decisions on whether to replace or amend the Guidelines.

Transpower New Zealand

Transpower is committed to playing its part to address climate change and help New Zealand transition to a low emissions economy. We are part of the Climate Leaders Coalition in New Zealand – standing publicly with many other businesses to declare and report on our mission to reduce emissions in New Zealand. We are actively seeking to reduce our own greenhouse gas emissions across all areas of our own inventory of emissions, and we are working hard to ensure we enable the transition to a low-emissions electricity future.

We consider that timely, efficient transmission investment will be vital to support New Zealand's commitment to the international community through the Paris Agreement. In our view, the Authority's proposal is at risk of exacerbating the well-documented energy affordability problems that are afflicting too many consumers and compromise the achievement of New Zealand's climate change objectives and commitments.

The problems the Authority has identified with the current TPM can, in our submission, be dealt with more quickly, more efficiently, and more cost-effectively through incremental reform of the existing TPM and Guidelines. This approach would also carry a lower risk of unintended consequences. We would welcome the opportunity to consider these options in conversation with the Authority, our customers and other stakeholders.

Yours sincerely

Alison Andrew
Chief Executive

Appendix 1: Options for incremental TPM reform

The table below lists some high-level examples of incremental reform options that are available to address the problems the Authority has identified with the current TPM.[25]

Problem	Incremental reform solutions include:
Interconnection charge	
The interconnection charge method spreads the costs of regional transmission investment too widely, across all New Zealand	• Tilted postage stamp • Regional postage stamp (using location as a proxy for benefit) • Regional postage stamp with net importing regions (and/or generators) picking up a proportion of the cost of net exporting regions
The current RCPD method sends a peak price signal that is too avoidable, shifting costs onto other parties	• Mean offtake as an allocator (in whole or part) • Two-part tariffs (fixed/volume/mean + peak usage)
The current RCPD method peak price signal is too high, promoting inefficient investment to avoid it	• Two-part tariffs (fixed/volume/mean + peak usage), perhaps with ability to dial-up the peak usage part as constraints are foreseen in short-to-medium term grid planning) • N (number of peaks) > 100
RCPD method can result in unpredictable year-to-year price volatility	• Multi-year averaging for capacity measurement
HVDC charge	
South Island generators pay for the inter-island HVDC link but North Island generators do not face an equivalent charge	• Bi-directional HVDC charge on generation in the sending island, calculated half-hourly
Generators in the upper South Island pay for the inter-island HVDC link despite that region being a net import region	• Exemption for upper South Island generators, or more general recognition of intra-South Island zonal import/export characteristics
HVDC charges on injection into the grid by South Island generators incentivise embedding of large-scale generation	• Generation plant with a capacity above a threshold is deemed grid connected

25 We canvassed many of these options in our Invitation to Comment on a possible 'Operational Review 2' of the current TPM, June 2017. The feedback from stakeholders was positive.

Transmission charges on generation	
Generators should contribute to the costs of transmission to the extent their location contributes to transmission investment needs	• Bi-directional HVDC charge on generation in the sending island, calculated half-hourly • Generators pay part of the interconnection charge • Use bilateral investment contracts to partially or fully fund transmission investment to release generation capacity

In our view, the problems relating to undergrounding costs and stakeholder engagement in investment decisions are adequately addressed through our regulation by the Commerce Commission under Part 4 of the Commerce Act.

We understand the Authority's concern that Transpower may, in future, be pressured by local communities or required by council policies to underground our assets in a way that pushes the associated (significantly higher) costs onto consumers in other communities. We agree this risk needs to be managed, but consider managing it through the TPM introduces significant implementation issues. In our view, management of this risk is more appropriately within the jurisdiction of the Commerce Commission where it is already well managed via its decisions on our individual price-quality path and our capex investment proposals. We believe these mechanisms are better able to respond over time to new and emerging trends, including societal expectations and technology changes, than the TPM. A possible solution may be for local communities to bear the incremental costs of any locally-required undergrounding directly through bilateral investment contract cost recovery outside our regulated asset base.

Appendix 2: Transpower's positions on the Authority's transmission pricing review

The Authority's transmission pricing review began in February 2011, with consultation amending the regulatory framework for the Transmission Pricing Methodology - specifically, to remove the pricing principles and the application and interpretation provisions from the Electricity Industry Participation Code.

To date Transpower has contributed 16 submissions and 2 cross-submissions, including this October 2019 submission. From the beginning our key messages have been strongly consistent.

Our submissions listed below, are all publicly available. The balance of the Appendix provides a snap shot of some key messages in the form of quotes from these submissions. The summary highlights that the views and positions we have expressed since of the Authority's transmission pricing review remain relevant to consideration of the 2019 Issues Paper.

February 2011	Code amendment proposal: Regulatory framework for Transmission Pricing Methodology (TPM)	submission
February 2012	Decision-making and economic framework for transmission pricing methodology review	submission
March 2013	Transmission Pricing Methodology: Issues and proposal	submission cross-submission
October 2013	TPM working paper – Transmission Pricing Methodology CBA	submission attachment: CEG report
November 2013	TPM working paper – Sunk Costs	submission attachment: CEG report
January 2014	TPM working paper – ACOT payments for distributed generation	submission
March 2014	TPM working paper: Use of LCE to offset transmission charges	submission
March 2014	TPM working paper: Beneficiaries-pay	submission attachment: CEG report
June 2014	TPM working paper: Connection charges	submission
September 2014	TPM working paper: LRMC charges	submission
October 2014	TPM working paper: Problem definition relating to interconnection and HVDC assets	submission
August 2015	TPM Options paper	submission appendix: CEG report appendix: Scientia report
July 2016	TPM: Second issues paper	submission appendix: guidelines mark-up appendix: Axiom report appendix PWC report appendix: Scientia AOB report appendix: Scientia gross demand report

February 2017	TPM: Second issues paper supplementary consultation	submission appendix: guidelines mark-up appendix: Axiom report appendix: ENA distribution pricing consultation submission
March 2017	TPM supplementary consultation: asset valuation	cross-submission
April 2017	TPM: Oakley Greenwood CBA	submission
October 2019	TPM 2019 Issues paper	Submission available here from 2 October 2019

Overall views on the proposal for radical change: "Having participated fully in this process to date and from a largely 'value neutral' perspective we have been unable to convince ourselves of the case for radical change. On the contrary, as the process progresses, it has become increasingly apparent that current TPM operates well and that a stable, simple and durable TPM is highly valued. We remain extremely concerned about the risk of unintended consequences or 'collateral damage' from radical reform." (October 2013)

Questions about EA work prioritisation: "a major structural change to the TPM would consume considerable scarce resources within the EA and across the industry at a time when the EA has far more urgent priorities that have the potential to provide greater long-term benefit to consumers." (February 2012)

"Transmission pricing is challenging and has a history of causing dispute. As a sector, we have allowed this challenge to divert resources and attention away from issues that have greater potential to improve outcomes for consumers." (March 2013)

Transpower is engaging constructively to try and help make the Authority proposals work: "Notwithstanding, our focus remains on helping the Authority reach a satisfactory conclusion to its review of the TPM Guidelines; this is reflected in the content of this submission. Similarly, if the Authority decides to issue new Guidelines, then we will do our best to develop those into a robust, workable and durable TPM." (February 2017)

We are open to changing the TPM: "To be clear, we are not averse to change where it makes sense, and consider that the investigation process has advanced understanding of some specific problems, e.g. … the strength of the UNI RCPD price signal, where there is clearly room for improvement (and potentially elsewhere). However, we simply do not think large-scale change makes sense and, rather than pursue radical departure from current arrangements, the investigation should focus on understanding and remedying the specific problems that have been identified." (October 2013)

"In practice there is no perfect TPM: we agree problems exist with the TPM and that these should be assessed (and addressed, as appropriate, where there are clearly superior alternatives to the current settings). We also agree there is no perfect TPM and consider that perfect should not become the enemy of good." (October 2014)

"Our preferred outcome for this review is a decision that yields a workable TPM. This means that it finds general acceptance among the main stakeholder groups and encourages our customers to sensibly manage their loads (to help us defer investment) and to sensibly engage in the grid investment process. Ideally this will not be excessively complex or costly to implement and operate." (October 2015)

"We agree there is scope to improve the current transmission pricing methodology (TPM) including to improve cost-reflectivity and the targeting of price signals and that this is likely to require some changes to the Guidelines." (July 2016)

An incremental approach should be taken: "It is …. clear from many submitters that the status quo for interconnection charging (aside from perhaps the HVDC charge) is preferred over the proposed use of the SPD method. Any further consultation should be on options to refine the existing arrangements, rather than on revisions to the original proposal." (28 March 2013)

"In our view, the problems with the status quo, if any, are minor and point to less radical and much simpler approach to transmission pricing than the Authority is proposing. In our view that approach should recognise the stability and efficiency benefits of the current TPM and focus on incremental improvements." (November 2014)

"We note that the current pricing arrangement of a regionally differentiated postage stamp interconnection charge and geographically-targeted HVDC charge already provides a relatively simple LRMC-like charge. As a less radical option, these charges could be modified over time to adjust price signals." (September 2014)

Connection charging framework is sound: "The majority of submissions from our connection customers agreed there is no material problem with the connection charging framework, and connection charging was not a focus for most submitters with no strong endorsement for change." (28 March 2013)

"The existing connection charge framework is fit for purpose and compatible with the investment and incentive regulation under Part 4 of the Commerce Act." (June 2014)

Interconnection charges may send too strong pricing signals: "With respect to the interconnection charge the Authority has not adequately defined the problem it sees with the current TPM. Apart from the 'signal strength' issues that, if established as material problems, are readily addressable the problem definition to date has essentially been a statement of faith and belief: that its preferred solution could be 'more' efficient than the status quo. This simply does not constitute a robust problem definition." (October 2013)

"… RCPD can over-signal the benefit of load-shedding …" (October 2014)

Qualified support for charging beneficiaries: "We support in principle the intent of improving investment efficiency by identifying and charging beneficiaries. However, the proposal raises concerns due both to its complexity, and the high risk of unintended consequences." (March 2013)

"… our broad support for beneficiaries-pay reflects that there are a number of options which would satisfy beneficiaries-pay, including the status quo; connection assets are charged to the sole beneficiaries (on a causer pays basis), South Island generators are major beneficiaries of the HVDC but, like the Authority's GIT based charge options, not the sole beneficiaries, and smearing interconnection costs across load on a postage stamp basis reflects the large fixed and common costs of the transmission grid, and should result in a situation where no consumer group or region pays more for interconnection than their private benefit." (March 2014)

Difficulty in identifying beneficiaries: "the charges will not accurately reflect the benefits of transmission investments (either in terms of approximating private benefits for individual parties, or providing a clear indication of overall benefits of investments)." (March 2013)

Removal of peak-usage charges would be undesirable: "Removal of a peak price signal could trigger an 'over-correction' where demand spikes lead to significant transmission investment being brought forward." (July 2016)

"A peak price signal is essential for an efficient TPM. We disagree with the Authority's reasoning and position on a peak Long Run Marginal Cost (LRMC) charge. The Authority's current path risks grid over-build and security problems which could swamp any benefits from TPM change." (February 2017)

Authority proposals could result in wholesale market distortions: "the charges may alter generator behaviours in ways that reduce the efficiency of the wholesale market. The economic costs of this may significantly outweigh any potential benefits." (March 2013)

"[Benefit-based] charges would not provide the intended locational signal to generators and could result in inefficient investment decisions, as well as adversely impacting operation of the wholesale energy market." (July 2016)

Proposals will undermine efficient investment: "The [Authority's] concern is that grid investment processes lack adequate stakeholder engagement and that there is a systematic risk of the Commerce Commission approving inefficient grid investments. We do not believe that evidence supports these concerns, or that the proposed pricing changes would improve investment efficiency. To the contrary, there is a risk that the proposal will motivate obstructive or vexatious engagement to the detriment of investment efficiency." (March 2013)

Proposals will increase disputes: "using a complex modelling approach to setting transmission pricing will only increase disputes." (March 2013)

Investor certainty undermined by current review: "ongoing reviews of the TPM reduce investor certainty, which is especially relevant to the timely commitment of new investment in generation." (February 2012)

"Investors would prefer a robust, enduring approach to transmission pricing that promotes a more certain commercial environment. Approaches which provide less certainty add to commercial risk, which increases some costs (e.g. borrowing costs), discourages some investment and reduces the values of some businesses." (February 2012)

"The length of the review is creating considerable uncertainty. While the Authority should not rush the remainder of the process, particularly if substantive changes to the TPM are further considered, there are a number of lessons that can be taken from the review that would help ensure it is robustly completed in a timely manner." (October 2014)

Need for transitional arrangements: "Large step changes to transmission prices can produce unintended consequences. The assessment of any amendments to the TPM that would result in large changes to individual customers' charges must account for the need for such amendments to be introduced by way of transitional arrangements." (February 2012)

Appendix 3: Case Studies - application of benefit-based charging

We have considered application of a simplified benefit-based charging regime in practice by considering a hypothetical need to upgrade the line between Wairakei and Hawke's Bay. We have undertaken this Case Study exercise as part of our efforts to explore ways in which the Authority's proposed benefit-based charge method (BBCM) could be made to work in a pragmatic, practicable and legally robust/certain manner.

The Wairakei-Hawke's Bay line case studies were chosen on the basis that they are relatively simple. To simplify further we have used approximate demands and costs, and have excluded consideration of the existing and any future transmission connection to the south. The case studies then don't need to consider the complexities of 'loop flow' and meshed characteristics of the wider interconnected grid which, combined with the large number of parties using the grid, may impact on the complexity and practicability of applying a BBCM. To simplify further we have considered only beneficiaries who are known load and generation transmission customers. This avoids practicability issues where the beneficiaries are unknown or the benefits are not attributable to existing individual transmission customers.

We have tested application of a BBCM to achieve full consistency with clause 24 of the 2019 Issues paper draft TPM Guidelines. Specifically, we have ensured consistency with "the treatment of the relevant electricity market benefit or cost elements under the test used by the Commerce Commission in its approval of the post-2019 benefit-based investment". We have done this by considering benefits exclusively from the Part 4 market benefit test.

We are mindful that it would be undesirable to have to separate benefit tests (investment test under Part 4 Commerce Act, and BBCM test under the TPM), which provide potentially different and inconsistent information about proposed investments.

The application uses market benefit as a proxy for private benefit which may be reasonable if the two are considered to be sufficiently or strongly correlated (consistent with clause 22(b) in the draft Guidelines). Clause 22(b) requires that the "proxies … result in an allocation of the benefit-based charge to each designated transmission customer who receives a major positive net private benefit from the benefit-based investment that broadly approximates the allocation that Transpower considers would have resulted had expected net private benefits been used to calculate the allocation". The extent to which our Case Study application meets this requirement is open to interpretation, and we detail some of the (known) reasons why there may be departures or differences.

We would welcome views from the Authority and other stakeholders about whether the approach we have taken for the Case Studies is considered to be a reasonable and workable approach that is consistent with the proposed TPM Guidelines and policy intent.

Case Study A: Load grows and triggers need for more transfer capacity into Hawke's Bay

Under Case Study A we have tested the scenario where load grows and triggers the need for more transfer capacity into Hawke's Bay.

The benefits we have identified are from reduced cost to meet load and resilience. We have assessed that Wairakei generators would receive 15% of benefits (using increased income as a proxy for benefit, and based on assumption the market is perfectly competitive and offers/prices are set at SRMC), and Hawke's Bay load receives 83% of the benefits (assessed as the reduced cost to meet load, using the cost of a diesel generator as the counter-factual).

The assumptions we have used for Investment Test purposes may impact the determination of benefits. For example, the results could be quite different if the perfect competition assumption[26] was loosened or if the counterfactual assumed new permanent generation plant in the Hawke's Bay region (see the Case Studies below) rather than diesel generation. These assumptions could overstate consumer private benefits and understate generator private benefits. Likewise, we have used revenue as a proxy for producer surplus. This could overstate producer surplus if price matched cost (which would be the case in a perfectly competitive market) and the new generator earned normal profits only. As a corollary to this, if the perfect competition assumption is loosened then the benefit generators get from the expanded line may include an element of economic rent and, therefore, higher producer surplus and benefit. What the overall impact of the use of proxies is on the BBCM allocations may be ambiguous.

The increase in load would increase the benefits of the existing line. We have not modelled this. Consideration would need to be given to whether the proposed TPM Guidelines re-opener triggers had been met, if the existing line was treated as a benefit-based Investment (as per the Additional Component provisions). We note that the benefits from the existing line won't necessarily be the same as the 85:15 benefit split for the upgrade.

If benefit-based charges were applied to the existing line and upgrade it might make sense to undertake a single benefit-based assessment for the existing line and upgrade. This also gives rise to the question whether, if the existing line is not a BB investment, whether the upgrade or new investment should trigger the existing investment becoming a BB investment. Consideration would need to be given to the complexities of applying the BBCM to existing, historic investments, and the implications that it could divorce the BBCM from the Part 4 Investment Test.

Case Study B: 150 MW new generation is built in southern Hawke's Bay

Under Case Study B we have assumed 150MW of new generation is built in Hawke's Bay, with two sub-scenarios: under B1 the cost of new generation in Hawke's Bay is 7c/kWh (cheaper than from Wairakei) and under B2 the cost of new generation is 10c/kWh (more expensive than from Wairakei).

Under scenario B1 the new generation is cheaper than existing Wairakei generation and is dispatched. Under scenario B2 it is more expensive but cheaper than the cost of unserved energy so is used to make up any deficit in supply from Wairakei/line constraints. Under both scenarios no transmission investment is economic so there is no need to undertake a benefit-based allocation assessment.

It should be noted the B1 assumption that the cost of new generation in Hawke's Bay is cheaper than Wairakei means the benefit Hawke's Bay consumers receive from the existing Wairakei-Hawke's Bay line may reduce, and may be lower than under the B2 scenario. The perfect competition assumption means that the Investment Test approach assumes

[26] The private benefits for generators would be greater in an oligopolistic market than a perfectly competitive market.

consumers will receive the full benefit of the lower SRMC. We have not modelled this, but consideration would need to be given to whether the proposed TPM Guideline re-opener triggers had been met if the existing line was a benefit-based investment.

Case Study C: 600 MW new generation is built in Hawke's Bay. To fully dispatch, need to expand Wairakei-Hawke's Bay

Under case study C there is 600MW of new generation built in Hawke's Bay. In order to be fully dispatched the Wairakei-Hawke's Bay line needs to be expanded. The new generation is assumed to be cheaper than Wairakei generation (as per scenario B1). The assumption that the new Hawke's Bay generation is cheaper than Wairakei means it is assumed that it would be fully dispatched if there are no line constraints.

The major beneficiaries are determined to be the Hawke's Bay generator with 71% of the benefit (increased dispatchable generation) and Wairakei load with 27% (reduced cost to meet load as the Hawke's Bay generation cost is 7c/kWh compared to Wairakei generation which costs 8c/kWh). Hawke's Bay load is a minor beneficiary with 2%.

The benefit to Wairakei load reflects that the Investment Test assumes perfect competition to the lower SRMC Hawke's Bay generation is assumed to benefit consumers. The outcome may be different (smaller benefit to Wairakei load, higher benefit to Hawke's Bay generation) if the perfect competition assumption was loosened. The modelling would need to include judgements about offer prices (and the extent they deviate from SRMC) and which generation sets the spot market clearing price.

Under a simple method the entire cost could be allocated exclusively to the Hawke's Bay generator and Wairakei load. Hawke's Bay load only get minor benefit from improved resilience (2% of the benefit). If a private benefit assessment was made it may be determined that Hawke's Bay load receives negative benefit as, in the absence of the line upgrade, there would be excess supply in Hawke's Bay which would suppress nodal prices in the region.

The new generation investment in the Hawke's Bay would reduce the benefit Hawke's Bay consumers receive from the existing Wairakei-Hawke's Bay line, particularly if the line becomes constrained (east to west). We have not modelled this, but consideration would need to be given to whether the proposed TPM Guidelines re-opener triggers had been met, if the existing line was a benefit-based investment. The 98:02 allocation would be unlikely to be suitable for application to the existing line as it had a different purpose and benefit (transporting electricity from Wairakei to Hawke's Bay) which would force departure from the BBCM and the Investment Test.

Case Study D: 600 MW new generation is built in southern Hawke's Bay. 300 MW new generation initially then second 300 MW generator built

Under Case Study D 300MW of new generation is built in southern Hawke's Bay (Generator 1). As with the Case Study B scenarios no new transmission is economic for the new generation. Under Case Study D a second 300MW generation plant is built (Generator 2) and to fully dispatch both the Wairakei-Hawke's Bay line needs to be expanded. The principle difference between Case Studies C and D is that there are two different new generators in Hawke's Bay in D. If a private benefit assessment was made it may be determined that Hawke's Bay load receives negative benefit as, in the absence of the line, there would be excess supply in Hawke's Bay which would suppress nodal prices in the region.

We make an important distinction between what caused the need for the new transmission line and who benefits from it. Generator 1 does not have any 'capacity rights' to the existing line. The change in market conditions, with development of a second generation plant in Hawke's Bay means both Generator 1 and Generator 2 would get the same (equal) benefit from the increase in line capacity i.e. both need the new line to be fully dispatched. Looked at another way, the new line would equally not be needed if Generator 2 entered the market and Generator 1 exited (plausible if Generator 2 is lower cost than Generator 1 and Generator 1 has high variable costs relative to sunk and fixed costs).

Generator 1 receives 35% of the benefit, Generator 2 receives just over 35% of the benefit, Wairakei load receives 27% of the benefit (reduced energy cost) and Hawke's Bay load receives 2% (reduced energy cost and resilience). If a private benefit assessment was made it may be determined that Hawke's Bay load receives negative benefit as, in the absence of the line, there would be excess supply in Hawke's Bay which would suppress nodal prices in the region.

The new generation investment in the Hawke's Bay would reduce the benefit Hawke's Bay consumers receive from the existing Wairakei-Hawke's Bay line, particularly if the line becomes constrained (east to west). We have not measured, but consideration would need to be given to whether the proposed TPM Guideline re-opener triggers had been met, if the line was a benefit-based investment.

Note that if the assumptions are changed such that Generator 1 is higher cost (variable cost) than Generator 2 then Generator 1 would receive a greater share of the benefits of the new line, because more of Generator 2's electricity would be dispatched under a constrained line scenario. Likewise, on a private benefit assessment, Generator 2 would receive a larger producer surplus than Generator 1 even if they generated the same amount of electricity. This highlights that BBCM allocations would be very dependent on the assumptions Transpower makes about the individual costs (including SRMC) of each generator's plant.

Appendix 4: Analysis of the Authority's proposed price cap

The TPM review process to date has shown the potential for very large transfers, some of which have the potential to affect the viability of enterprise or the economic wellbeing of residential consumers. We consider there to be a need to include or retain transition provisions in the TPM Guidelines. We are open to the inclusion of a price cap. However, we have a number of practical and substantive concerns with the design of the price cap and its expression in the draft Guidelines. These are largely the same as the concerns we expressed in response to the Supplementary Consultation (February 2017).

The specification of any price cap/transition mechanism should recognise the optimal design, including length of transition etc, can depend on the scale of the price shocks/changes. This would depend on a number of factors including when the new TPM is introduced, finalisation of Schedule 1, decisions on what the methodology is for setting Residual Charges and other factors that wouldn't be known until after the Authority has made final decisions on whether to change or replace the TPM Guidelines.

An effective price cap would also smooth the transition from current to new prices over a period of time i.e. delay when customers incur the full price increase/receive the full price decrease.

The Electricity Authority's 'price cap' would allow major price shocks for many consumers

We are concerned about the size of the price shocks that would result from the Electricity Authority's proposals. The Commerce Commission has capped network price increases at 9% (applicable to Aurora Energy for the 2025-25 DPP reset) under Part 4 of the Commerce Act in order to avoid price shocks for consumers. The Authority's proposed price cap would result in a number of undesirable outcomes:

- The price cap would result in many transmission customer's prices going up initially by more than they would absent the price cap (including 15 of the electricity distributors).
- The price cap would exacerbate price shocks for transmission customers that would incur higher transmission charges e.g. Westpower would face an initial price increase of 110% under the cap rather than 101% without the cap, Network Waitaki would face an increase of 55% rather than 51%, The Lines Company 50% rather than 46%, and Top Energy 32% rather than 29%.[27]
- The price cap would result in some transmission customers (Counties Power and Contact Energy) whose prices would otherwise go down initially facing a price increase.
- The price cap would result in the customers that would get the biggest benefits (price reductions) from the new TPM getting proportionately more benefit straightaway than customers that would get smaller benefits e.g. Meridian would receive an

[27] Note that for modelling convenience, the Authority has adopted 2022 for the assumed implementation date for the new TPM. The assumed implementation date may impact on some of the assumed results e.g. if the implementation date is after 2022 then electricity retail prices may be higher than the Authority has assumed, meaning that transmission charges would not be able to increase as much before the cap takes effect.

(uncapped) 42.62% reduction in transmission charges and receives 96.77% of this in year one, NZAS would receive a 22.11% reduction uncapped and receives 91.55% in year one, and Unison Networks would receive a 4.80% reduction and would receive 52.42% of the benefit in year one.

- The price cap would result in some situations where customer A is facing a higher initial price increase than customer B yet customer B would face a higher price increase without the cap or after the price cap has been unwound e.g. NZ Rail and Buller Electricity face similar price shocks without the cap, of 157% and 149% respectively, but the price cap lowers the initial impact for NZ Rail by 120% and for Buller by only 51%.
- The price cap would result in situations where customer A and customer B would face the same increase without the price cap but a different initial increase under the cap e.g., absent the price cap, Buller Electricity would face a transmission price shock of 149% and Westpower would face a price shock of 110%. The price cap provides Buller with substantially bigger initial protection, reducing the price shock by 51% compared to less than 10% for Westpower. The impact is to flip the increases with Buller initially facing a lower initial increase of 98%, compared to Westpower with an initial increase of 101%, despite the fact that Buller's prices would ultimately go up by more than Westpower.

Level of price shocks under the Authority's proposed price cap

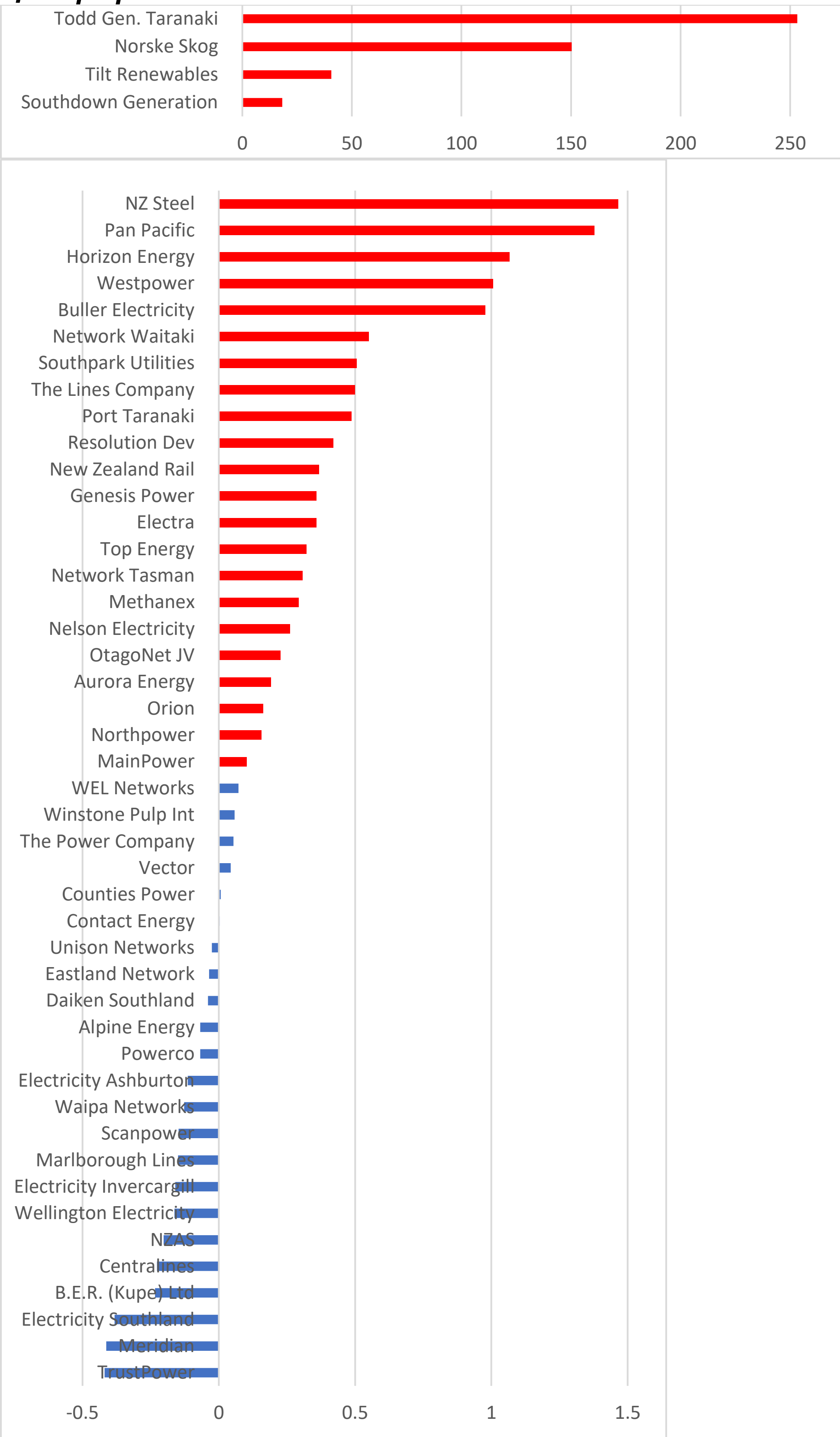
According to the Authority's calculations[28], half of all EDBs would be subject to price shocks ranging up to 98% increase in transmission charges for Buller in the first year of the new TPM, 101% increase for Westpower and 107% for Horizon.

The Authority's changes in transmission charges could undermine the Commerce Commission's attempt to avoid price shocks. For example, the effective impact of the change in transmission charges for Aurora would push its price increases up from the Commerce Commission's cap of 9% to the equivalent of a 15% increase.

The impact is even more significant for most major users, other than NZAS. The initial increase for Pan Pacific, NZ Steel, Southdown, Tilt, Norske Skog and Todd range 138% to 25,231%.

[28] Electricity Authority TPM review 2019 Issues Paper Table 12.

Figure 1: Electricity Authority's estimate of transmission price changes in the first year of the proposed new TPM[29] [30]



29 Based on data from the Authority's 2019 Proposals Impact Modelling spreadsheet.
30 Calculations are based on introduction of new TPM for 2022.

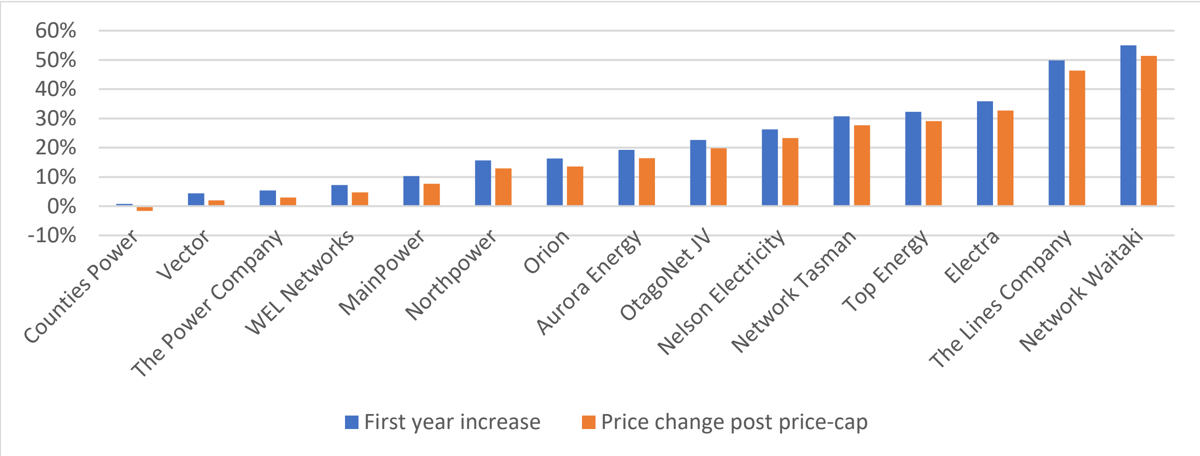
The Authority’s proposed ‘price cap’ would result in unintended consequences

A price cap or transition would normally simply slow the rate of price increase (or decrease) to avoid price shocks. The Authority’s proposal does not do this.

For the majority (15) of EDBs the price cap results in the initial price increase being higher than they would face without the cap, with transmission prices then reducing in subsequent years. In the case of Counties Power (and Contact Energy) the Authority’s proposals are supposed to result in a reduction in transmission costs, but they initially instead would go up.

For the majority of these EDBs the impact of the price cap is actually to exacerbate the level of the price shock e.g. The Lines Company transmission prices would go up by 50% in the first year, instead of 46% without the price cap. Network Waitaki similarly would face an initial increase of 55% instead of 51%.

Figure 2: Initial transmission price increases for electricity distributors under the proposed price cap[31]



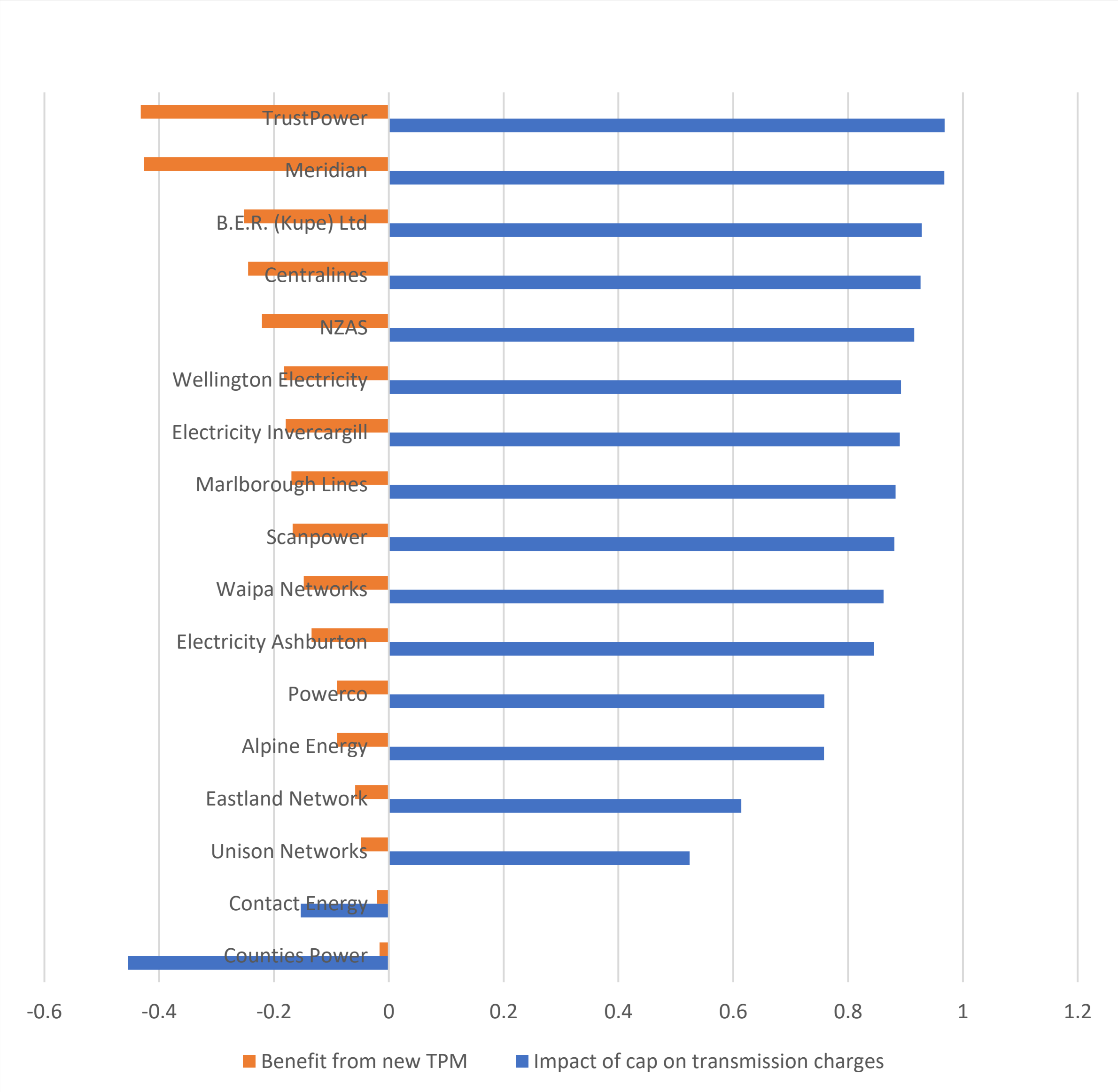
The transmission customers that would receive price reductions get all but 1.36-2.35% of the price reduction straightaway, without any real transition. For example, Meridian gets a 41.25% reduction straightaway, and initially misses out on 1.38% of the reduction they would ultimately receive. In contrast, Contact who would ultimately receive a reduction of 2.04% faces an initial price increase of 0.31%. The rapid phase in for transmission customers that are getting price reductions is funded by increasing the charges of the majority of transmission customers facing increases by increasing their charges by more than would occur absent the price cap.

The cap also results in the customers that would receive the largest benefits from the TPM having their price reductions least effected by the price cap e.g. Meridian would receive a (uncapped) 42.62% reduction in transmission charges and receives 96.77% of this in year one, NZAS would receive a 22.11% reduction and receives 91.55% in year one, Electricity Ashburton would receive a 13.43% reduction and would receive 84.54% in year one, Unison Networks would receive a 4.80% reduction and would receive 52.42% of the benefit in year

[31] Based on data from the Authority’s 2019 Proposals Impact Modelling spreadsheet.

one, Contact would receive a 2.04% reduction and their price actually goes up initially by 15.34%.

Figure 3: Direct correlation between size of price reductions and how much of the reduction customers receive straightaway under the price cap[32]



32 Based on data from the Authority's 2019 Proposals Impact Modelling spreadsheet.

Economic review of transmission pricing review consultation paper

A report for Transpower

September 2019

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Abbreviations

Term	Definition
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AoB	Area of Benefit
Authority	Electricity Authority
Axiom	Axiom Economics
BB	Benefits-based
CCGT	Combined Cycle Gas Turbine
CBA	Cost-benefit Analysis
Commission	Commerce Commission
DER	Distributed Energy Resources
DHC	Depreciated Historical Cost
DMEF	Decision-Making and Economic Framework
EDB	Electricity Distribution Business
HAMI	Historical Anytime Maximum Injection
HVDC	High Voltage Direct Current
IHC	Indexed Historical Cost
ICP	Installation Control Point
IPP	Individual Price-Quality Path
LNI	Lower North Island
LRMC	Long Run Marginal Cost
LSI	Lower South Island
MBIE	Ministry of Business, Innovation and Employment
MISO	Midcontinent Independent System Operator
NPV	Net Present Value
RCPD	Regional Coincident Peak Demand
SIMI	South Island Mean Injection
SPD	Scheduling Pricing and Dispatch
SRMC	Short Run Marginal Cost
TFP	Total Factor Productivity
TPM	Transmission Pricing Methodology
UNI	Upper North Island
USI	Upper South Island
WACC	Weighted Average Cost of Capital

Key messages

The proposal lacks a sound economic foundation

Replacing the regional coincident peak demand (RCPD) and high voltage direct current (HVDC) charges with a benefits-based (BB) charge and a residual charge would not provide the right forward-looking price signals:

- the explicit *ex-ante* signals provided by nodal prices and losses would not provide sufficient signals to grid users of the costs that Transpower would incur in the long run when it replaces or upgrades its assets;
- the implicit *ex-ante* 'shadow price' signals provided by BB charges would not provide a predictable, accurate signal of Transpower's long-run costs to which grid users could respond – even if they were inclined to do so; and
- the proposal would therefore give rise to *inefficient* price signals that would cause load and generation to make undesirable consumption and investment decisions, compromising allocative and dynamic efficiency.

The proposed methodology would not be fairer, more durable or improve the quality of new investment approval processes because (amongst other things):

- the proposal would create a tremendous amount of additional uncertainty and would lead to far more disputes in relation to countless matters;
- charging customers based on uncertain estimates of benefits would not necessarily be 'fairer' and applying BB charges to only a sub-set of existing investments would clearly be inequitable; and
- if the proposal has any effect on the grid investment approval process it is likely to be negative, since it would create more sources of dispute and generate incentives for parties to strategically withhold information.

Like its predecessors, the proposal does not have a sound theoretical foundation. It would not provide more efficient forward-looking price signals or result in a superior allocation of sunk costs.

The quantitative CBA is irredeemably flawed

The main piece of fresh analysis is a new cost-benefit analysis (CBA) to replace Oakley Greenwood's deficient modelling. Regrettably, the new CBA is just as flawed – if not more so – than its ignominious predecessor:

- neither the grid use model (which generates 96% of the estimated net benefit) nor the top-down modelling reflect the methodology that the Authority has proposed;
- the net benefit estimate mistakenly includes $2.3b in bare wealth transfers that are neither benefits to New Zealand's economy nor improvements to the overall efficiency of the electricity industry;
- the analysis ignores the cost of ~$1.9b of additional investment that is estimated to be needed to produce the supposed benefits, introducing an enormous bias into the modelling;

- the modelling rests on assumptions that do not reflect the ways in which the electricity market works or that the participants within it act; and
- aspects of the modelling hinge crucially on assumptions and inputs that are completely arbitrary or that lack any objective foundation.

Addressing the errors described in just the second and third bullets reduces the Authority's net benefit estimate to **-$1.5b**, i.e., to a net cost.[1] The CBA is therefore of no probative value and lends no support to the proposed methodology.

1 This figure is obtained by taking the $2.7b net benefit estimate and subtracting $2.3b then $1.9b. We are not suggesting that this represents a sound estimate of the likely net benefit – or cost in this case – from implementing the proposal. It is simply the revised result that one obtains when the two issues are addressed. Even with those corrections, the CBA remains unfit for its intended purpose on account of the many other shortcomings identified in this report.

Executive summary

This report has been prepared by Hayden Green[2] of Axiom Economics (Axiom) and Eli Grace-Webb[3] of farrierswier on behalf of Transpower. Its purpose is to evaluate the Electricity Authority's (Authority's) third transmission pricing review consultation paper ('Third Issues Paper').[4] Axiom's reports[5] in response to the second issues paper[6] and the supplementary paper that followed it[7] highlighted several problems with the proposals contained within them. Most notably, that:

The proposal is largely unchanged from the Second Issues Paper.

- the combination of nodal prices and the so-called 'shadow prices' associated with the proposed 'area of benefit' (AoB) charge (the precursor to the benefits-based (BB) charge) would not provide customers with an efficient *ex-ante* price signal of Transpower's future investment costs, and an *explicit ex-ante* price signal of some kind would better promote dynamic efficiency, such as a long run marginal cost (LRMC) charge;
- there was no reason to be confident that allocating the costs of investments after they had been sunk via the AoB charge would promote static efficiency or be more equitable overall, yet there was good reason to expect the proposal would result in more disputes and much higher administrative costs; and
- the cost-benefit analysis (CBA) that had been undertaken by Oakley Greenwood[8] was not fit for its intended purpose, did not provide a robust indication of the likely impacts of the proposal and so could not reasonably be relied upon to support the proposed methodology.[9]

Two years later, the Authority has produced a new CBA, but the broad scheme of the proposal is largely unchanged. The AoB charge has been rebranded the 'BB

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3 Eli is a New Zealand-based Director of farrierswier. Eli is an experienced economist who specialises in infrastructure economics. Qualified in law, economics and finance, Eli has diverse experience across electricity, water and gas networks, port, road and other infrastructure, and primary sector industries.

4 Electricity Authority, *2019 issues paper, Transmission pricing review, Consultation paper*, 23 July 2019 (hereafter: 'Third Issues Paper').

5 Axiom Economics, *Economic Review of Second Transmission Pricing Methodology Issues Paper*, *A Report for Transpower*, July 2016 (hereafter: 'Axiom Report on Second Issues Paper'); and Axiom Economics, *Economic Review of Transmission Pricing Supplementary Consultation Paper, A Report for Transpower,* February 2017 (hereafter: 'Axiom Report on Supplementary Consultation Paper').

6 Electricity Authority, *Transmission Pricing Methodology: Issues and proposal, Second issues paper,* 17 May 2016 (hereafter: 'Second Issues Paper').

7 Electricity Authority, *Transmission Pricing Methodology: Issues and proposal, Second issues paper, Supplementary consultation,* 13 December 2016 (hereafter: 'Supplementary Consultation Paper').

8 Oakley Greenwood, *Cost Benefit Analysis of Transmission Pricing Options, prepared for: NZ Electricity Authority,* 11 May 2016 (hereafter: 'OGW CBA').

9 On 26 April 2017, the Authority conceded that the Oakley Greenwood's CBA was irrevocably flawed and put a halt to its review (see media release: here).

charge',[10] but the key features are very similar. Transpower has asked us to review the material set out in the new consultation package and consider whether it affects any of the conclusions set out in the two previous Axiom reports, summarised above. In short, it does not. In our opinion, it has not been shown that the proposed approach would provide more efficient forward-looking price signals or a superior allocation of sunk costs.

General observations

The TPM consultation has been underway now for more than seven years.[11] During that time, nineteen consultation documents have been released spanning more than 2,000 pages. Five variants of 'benefits-based' charging have been put forth as proposed replacements to the current TPM – each of them globally unprecedented – with three CBAs. Progress has not been smooth.[12] Stepping back, there are several significant overarching problems with the way in which the review has been conducted and conclusions have been reached.

Inconsistencies and enduring features

Some quick numbers…

7+ Years this process has been going	**19** Papers on which the Authority has consulted	**5** Approaches the Authority has proposed
3 Cost-benefit analyses of those various proposals	**2,000+** Pages of consultation documents	**1,000+** Submissions lodged

There are many inconsistencies across the nineteen consultation papers released during the TPM review.

There are now numerous inconsistencies across the nineteen consultation papers that have been released throughout the review. To be clear, there is nothing wrong with a regulator changing its mind. Indeed, it is a regulator's prerogative – oftentimes its obligation – to shift its position in the face of well-reasoned submissions or other evidence. However, what we have seen recurrently throughout the last seven years is neither a gradual evolution nor a commendable responsiveness to compelling critiques. There have instead been numerous instances of the Authority abruptly reversing itself on key matters with very little explanation – if any.

10 Incidentally, this rebranding has not happened everywhere. The term 'AoB' is still used in the working files underpinning the new CBA.

11 In our experience, this is not a remotely typical timeframe for a review of this nature. To put it in some perspective, it took just over eight years for the United States to put a man on the moon following President Kennedy's grand announcement in 1961.

12 There is perhaps no better example of this than the fact that, in September 2014 (see Appendix E), the Authority released a working paper in which it sought to articulate the problem that it had purportedly been trying to solve for the previous two and a half years. It was the tenth consultation document that had been released up to that point. Problem definition is customarily the first step in any regulatory review.

In our experience, when a regulator changes one of its positions, it is customary for it to clearly articulate why – especially when it represents a critical part of the decision ultimately made, which has frequently been the case over the course of this review. One of the most noticeable discrepancies is in relation to one of the key purported benefits of the current proposal – and of the BB charge in particular.

Specifically, as we will explore in more detail later in this report, it has been said that introducing a BB charge would promote 'durability' and improve certainty. Yet, it was the perceived *lack of durability* associated with 'locking-in' BB charges for prolonged periods that led to the so-called 'SPD approach' (that involved continually 'updating' beneficiaries) being preferred in the first issues paper, when it was released in October 2012:[13]

The Authority has said previously that the proposed approach would ***not*** *be durable.*

> *'The approach proposed by Professor Hogan of applying beneficiaries pay involves determining the charge that would apply to parties prior to an investment, with the charge fixed over time. Although this approach has some merits, the Authority considers that a key difficulty with such a charge is* ***it is calculated on the basis of anticipated benefits rather than actual benefits****. This creates a risk for efficient investment as parties will be reluctant to invest if they may continue to be subject to a charge even though they no longer benefit from the investment. This could adversely affect competition and does not take into account new entry.*
>
> *Although allocating FTRs to parties subject to the charge may mitigate the adverse impacts of such a fixed charge to some degree, this would not address situations such as a major beneficiary exiting the market. Although the charge could be recalculated if such an event occurred,* ***this would inevitably be subject to considerable dispute, threatening the durability of the approach****. By contrast, the SPD method does not suffer from these problems.'* [our emphasis; internal footnote removed]

It is curious that something that was perceived to be a core *weakness* of the 'lock-in' approach seven years' ago is now apparently viewed as one of the BB charge's principal *strengths*. No reasons are provided for this reversal in logic.[14] Some other examples of prominent unexplained contradictions are summarised in Table ES.1 below, and many more will be encountered as we make our way through the various specific issues throughout the remainder of this report.

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13 Electricity Authority, *Transmission Pricing Methodology: issues and proposal, Consultation Paper,* 10 October 2012, p.104.

14 As we elaborate in more detail at various points throughout this report, in our opinion, locking-in beneficiaries would be highly unlikely to improve the durability of the regime.

Table ES.1: Examples of inconsistences

Issue	Current position	Contradicted by…
Nodal prices: can they incentivise efficient long-term investment?	The Authority contends that there is no need for an additional *ex-ante* price signal such as an LRMC-based charge to incentivise efficient new investment. It says that nodal prices can result in efficient short-term grid usage decisions *and* the right long-term investment outcomes.	The Authority has said in several prior papers[15] that nodal prices by themselves are *not* sufficient to incentivise efficient long-term investments. The about-face also creates an irreconcilable conflict in its proposal, i.e., if no other forward-looking price signals are needed then, logically, the implicit price signals provided by the BB charge would also be unnecessary and inefficient.
Shadow prices: predictable or not?	The Authority says it is not necessary to provide an explicit price to customers *before* new investments are made to efficiently signal the incremental costs, since they would be able to predict their future BB charges and 'rationally self-ration' based on those 'shadow prices'.	The Authority has acknowledged previously the implausibility of customers making the types of predictions that would be needed for its 'shadow pricing theory' to hold.[16] It conceded that this could not feasibly be done, in practice.
Principal benefit: superior grid use or investment?	Around 95% of the Authority's net benefit estimate ($2.6b of $2.7b) is said to flow from improved grid use.[17]	Previously, the Authority has extoled above all the importance of the TPM delivering more efficient investment outcomes.
Costs: which ones need to be counted?	One of the benefits that the Authority claims would flow from its proposal is 'more efficient investment in batteries'. This would supposedly arise in the form of an *avoided cost*, i.e., $202m of investments in batteries etc., would apparently be prevented.	In the Authority's modelling, the achievement of this $202m cost saving is contingent on an additional $1.9b being spent on generation. Yet, this additional expense (which is nearly ten times bigger) is not included as a cost in the CBA.
Timing of review: is reform needed now or not?	The Authority considers that changing the TPM is necessary and becoming increasingly urgent, since it is supposedly leading to inefficient investment and consumption outcomes.[18]	If the Authority's CBA model is taken at face value (with all its flaws) the proposal would not deliver a significant net benefit for *twelve years*. The CBA assumes also that within that timeframe (within *eleven* years) a significant 'uncertainty event' (such as a major TPM review) would take place. It is consequently unclear why this reform is warranted *now*.

15 *See for example:* Electricity Authority, *Transmission Pricing Review, TPM options, Working paper,* 16 June 2015, p.53; and Electricity Authority, *Transmission Pricing Review, LRMC charges, Working paper,* 29 July 2014, p.29.

16 *See for example:* Electricity Authority, *Review of distributed generation pricing principles, Consultation Paper*, 17 May 2016, Appendix E.2-E.3.

17 As we explain subsequently, this $2.6b estimate is almost entirely comprised of bare wealth transfers (that are not benefits in any meaningful sense) and the methodology by which it has been derived is profoundly flawed.

18 Third Issues Paper, p.ii.

Every proposal has been globally unprecedented and would have increased prices for North Island load customers.

Amongst all this upheaval, there are two aspects of the proposals that have been unerringly consistent. The first is that every methodology proposed over the course of the review has been globally unprecedented – at least to our knowledge. The latest proposal is no exception. Although there are some examples of jurisdictions in which the costs of *new* transmission investments are allocated to broadly defined customer groups based on an estimate of benefits, there are no close approximations to what has been recommending here.

We are also unaware of any transmission pricing reforms that have been motivated by a desire to reallocate the sunk costs of past investments. These reallocations – principally to North Island load customers – have been the second enduring feature of each proposal. As past reports have explained,[19] no dynamic efficiency gains can be achieved through such reallocations and the potential for static efficiency losses is obvious. Moreover, there is no logical basis to reallocate a relatively arbitrary set of *some* past investments – in this case, seven – but not others. That is presumably why the Authority's net benefit estimate *increases by $18m* when those seven investments are excluded from the BB charge.

Analytical approach

The way in which the respective merits of alternative pricing options have been evaluated has also been conspicuous. It has been a common practice to contrast an unduly narrow version of an alternative proposal with an idealised and unrealistic variant of the preferred option. Shared traits are viewed through a different lens, depending upon which charge is under consideration at that particular moment. A prominent example is the way that the uncertainty and inaccuracy surrounding the derivation of BB and LRMC prices are respectively perceived:

An unbalanced approach has been taken when analysing different pricing approaches.

- the Authority acknowledges the substantial uncertainties and inaccuracies that would afflict the estimation of private benefits under its proposed BB charge, but maintains that this does not represent a fundamental weakness,[20] i.e., the charge is included in the CBA and, ultimately, recommended; yet
- when assessing LRMC pricing, the Authority emphasises repeatedly the uncertainties and potential inaccuracies associated with the methodology[21] (all of which are surmountable given the approach's widespread application and none of which are as significant as those associated with the BB charge) and opts ultimately to not even include such an option in the CBA.[22]

In a similar vein:

19 *See for example:* Green *et al*, *Transmission Pricing Methodology – Economic Critique*, February 2013, p.2.

20 Third Issues Paper, p.142.

21 Electricity Authority, *Nodal pricing and LRMC charging*, pp.2, 5 and 24.

22 This decision is perplexing because it contradicts the advice contained in the Authority's own LRMC paper, which recommended that the option be tested further – including through a CBA. *See:* Electricity Authority, *Nodal pricing and LRMC charging*, p.2. The Authority has also been encouraging distribution businesses to use LRMC principles to introduce more cost-reflective tariffs – and several businesses have been doing so.

- one of the principal rationales for rejecting LRMC-based charging options is the proposition that nodal prices alone can be relied upon to elicit efficient long-term investment decisions – this is said to obviate the need for any additional explicit LRMC-based price signals; but
- if that contention were true (which it is not[23]), it would apply equally to the BB charge, i.e., The Third Paper states clearly[24] that the BB charge would provide an implicit price signal to users and so, applying the same logic, it would also be unnecessary and inefficient.

The analyses and conclusions have hinged on certain assumptions about how the electricity market functions that do not hold.

Analyses and conclusions have also often hinged on certain assumptions about how the electricity market functions that do not hold. A clear example of this from the Third Issues Paper is the assumption adopted in respect of nodal price signals and the extent to which parties would respond to them. It is assumed that grid usage patterns would be the same whether retail customers are exposed directly to nodal prices or not, since the conduct of other parties – e.g., retailers – would compensate. That it plainly not the case. One of the primary roles of most retailers is to 'smooth out' nodal price fluctuations.

The influx of generation that has been forecast to occur in the mid-2030s under the proposal is similarly divorced from reality. The model that predicts this step-change in investment ignores the most important determinant of entry decisions: projected *future* cashflows. It is instead assumed that generators would assess the financial viability of potential investments by looking only at past and current returns. This is problematic, because:

- the model is suggesting that wholesale prices would drop sharply after this wave of new entry occurs – indeed, that is what is contributing most of the net benefit in the CBA (which is flawed, for reasons we discuss subsequently); but
- it appears not to have been recognised that, if spot prices would drop by so much and so fast following those new investments, then it is highly unlikely that all those generators would choose to enter in the first place.

These persistent issues have had a profoundly negative effect on the conclusions that have been reached throughout the review. It has led to the embracement of radical, globally unprecedented approaches lacking sound economic foundations at the expense of more incremental, tried-and-tested reforms. This latest proposal is no exception. These problems have also adversely affected the CBA which, like its predecessor, cannot provide any meaningful insight into the economic merits of the proposed methodology.

Forward-looking price signals

Nodal prices play a vital role in incentivising efficient short-term grid usage decisions. However, as the Authority itself has acknowledged previously (and

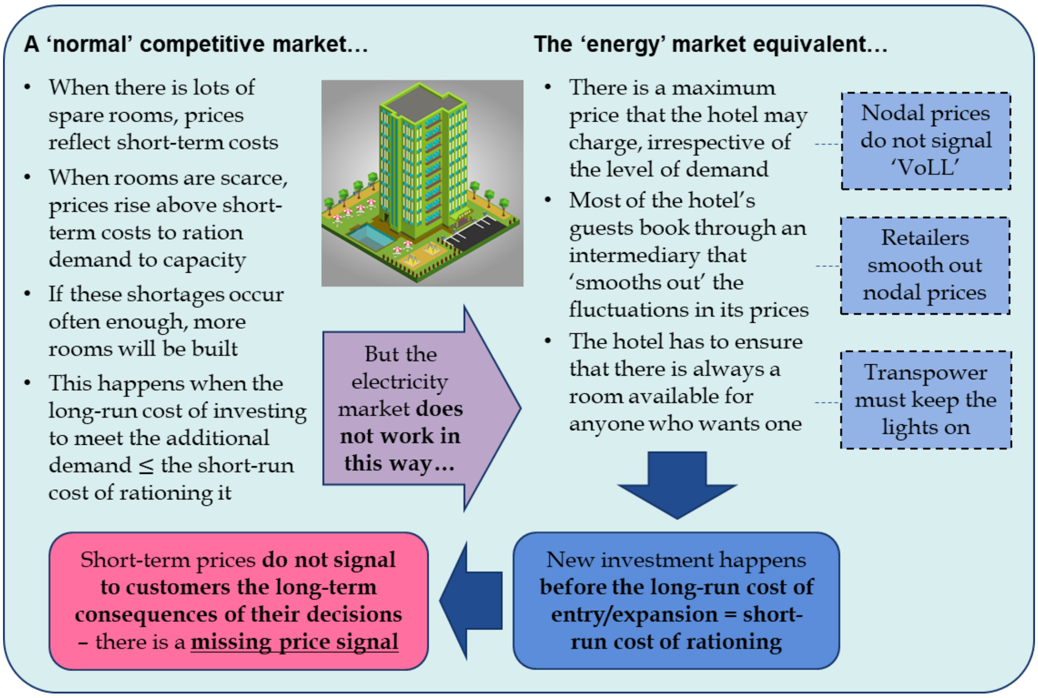
23 We explain why the proposition is incorrect in section 3.1.

24 Third Issues Paper, p.217.

unambiguously[25]), the basic economics of transmission mean that they do not signal adequately long-run investment costs. For customers to be made aware of the impacts of their actions on Transpower's *future* costs *before* they are incurred, something more than the signal provided by nodal prices is needed. The 'hotel analogy' in Figure ES.1 illustrates why the TPM has a potentially important role to play in 'plugging this gap'.

Nodal prices do not signal adequately long-run investment costs, leaving a 'missing price signal'

Figure ES.1: A hotel analogy – the missing price signal



The Authority considers and dismisses a number of options – including the LRMC-based pricing approach that is employed frequently by regulators throughout the world. As we noted above, it does so in large part because it claims – incorrectly (see Figure ES.1) – that nodal prices can be relied upon to elicit efficient investment outcomes. Having arrived at that (erroneous) conclusion (that also contradicts its own prior position), it then proposes to implement a BB charge that it says *would* elicit desirable behavioural change via an implicit (or 'shadow') price signal. The basic premise is that:[26]

- when deciding when and how to use the grid, customers would consider the impacts of their actions on Transpower's future investment requirements; and
- they would then deduce the future BB charges that they would face under various scenarios and, if appropriate, 'rationally self-ration'.

This proposal is puzzling because, as we have explained already, if nodal prices alone can be relied upon to elicit efficient long-term investment decisions, then why would there need to be any additional signal provided by the BB charge?

[25] *See for example:* Electricity Authority, *Transmission Pricing Review, TPM options, Working paper,* 16 June 2015, p.53; and Electricity Authority, *Transmission Pricing Review, LRMC charges, Working paper,* 29 July 2014, p.29.

[26] Third Issues Paper, p.217.

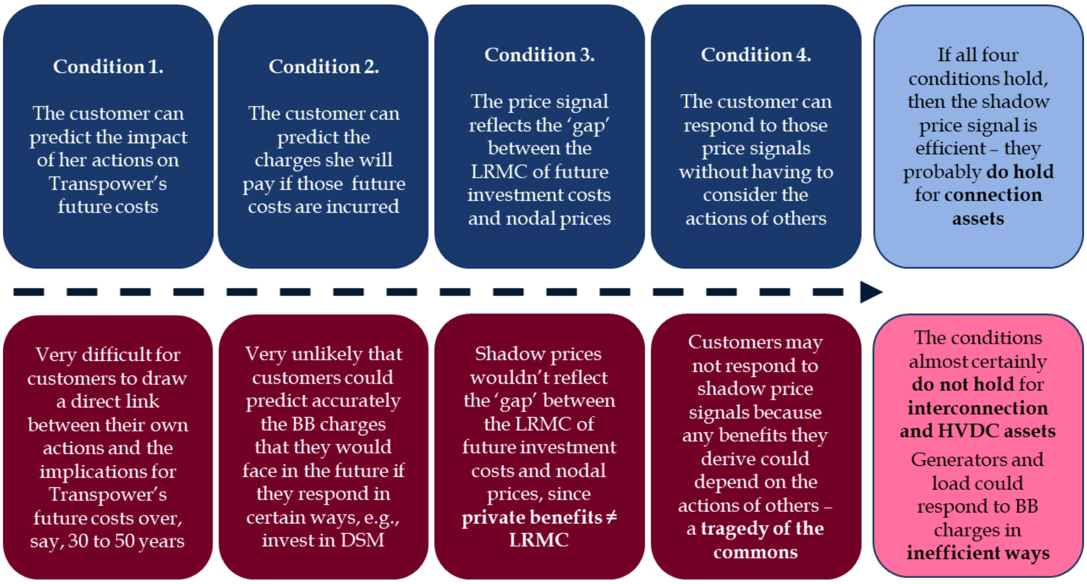
Nodal prices must either be sufficient to render redundant all additional price signalling methodologies – LRMC, RCPD, BB charges, etc., – or none. The answer is the latter.

Tautologically, nodal prices must either be sufficient to render redundant *all* additional price signalling methodologies – i.e., LRMC, RCPD, BB charges, etc., – or none of them. For the reasons set out above, the answer is the latter – nodal prices do *not* signal adequately long-run investment costs.

The question therefore remains: what is the best way to provide that additional signal? In our opinion, the proposed BB charge is *not* the best solution – or a solution *at all* for that matter. It is deeply flawed from an economic perspective. As previous Axiom reports[27] have explained and Figure ES.2 below illustrates, implicit prices are only efficient in very limited circumstances. None of the relevant conditions are met in this case. It follows that the BB charge would *not* send an efficient forward-looking price signal.

The BB charge would not provide an efficient 'shadow price' signal.

Figure ES.2: The conditions for an efficient shadow price do not hold



Quite simply, the BB charge would not work in the way the Authority envisages. It would not provide a predictable, accurate signal of Transpower's long-run costs to which grid users could respond – even if they were inclined to do so. Moreover, in the highly unlikely event that BB charges *did* function in the way that the Authority has contended, the net result would be an increase in the effective prices that customers paid for transmission services, which could lead to substantial distortions to consumption and investment decisions.[28]

This is because the *implicit* 'shadow price' component would be *in addition* to all the other *explicit* charges (connection charges, BB charges applied to existing assets,

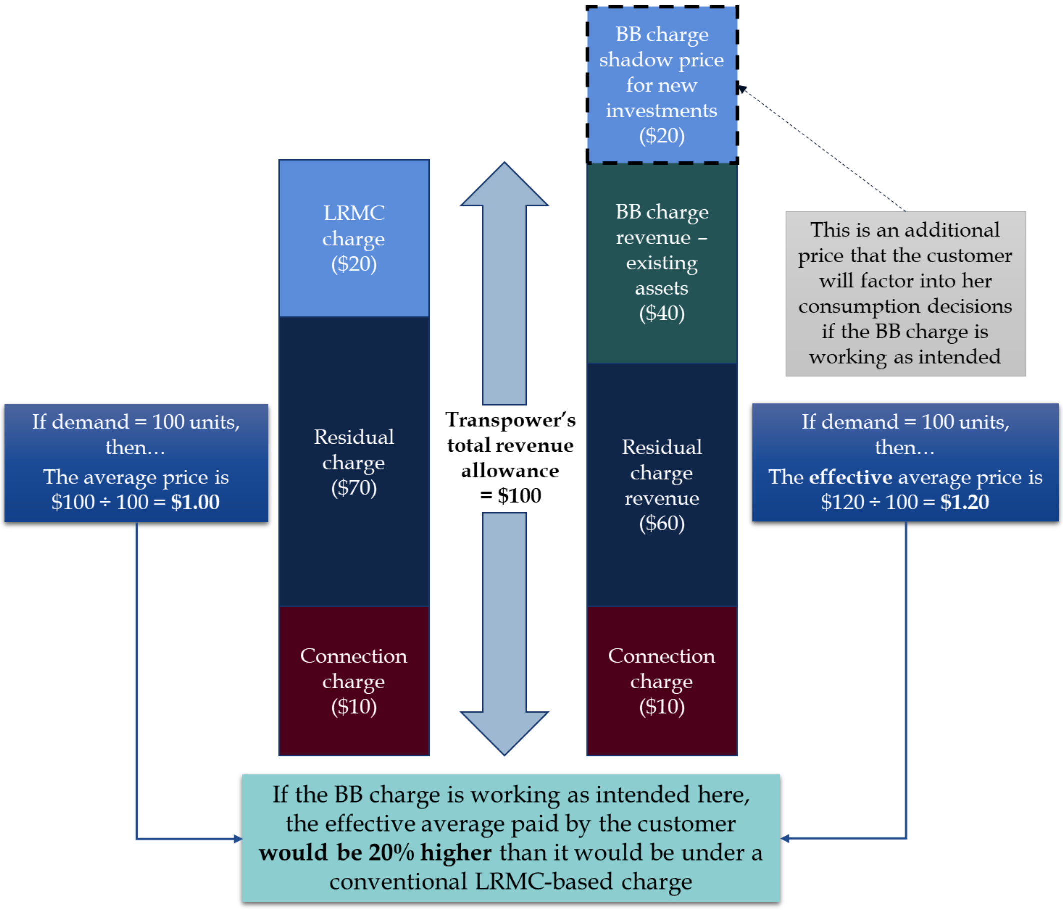
[27] *See:* Axiom Report on Second Issues Paper, pp.14-20; and Axiom Report on Supplementary Consultation Paper, pp.17-21.

[28] Even if that 'effective' price increase manifests simply in higher fixed charges, it is unrealistic to think that this would have no detrimental effects on efficiency. Specifically, it would require one to be confident that the long-term price elasticity of demand in response to changes in fixed transmission price components is *zero*, which seems highly unlikely, if not implausible. Moreover, as we explain subsequently, BB charges would not necessarily be 'fixed' in any case. Rather, there are numerous circumstances in which they could be revisited. It is therefore possible that Transpower would be constantly revising BB charges – introducing a high degree of variability into those prices over time.

residual charges, etc.) that, between them, would deliver-up Transpower's total revenue requirement. Figure ES.3 illustrates that the overall effect of this would be an increase in the *average effective price*, which would be likely to have distortionary effects. In other words, regardless of whether the BB charge worked as described, the net result would be the same: inefficiency.

Even if the shadow price functioned in the manner intended it would still be inefficient.

Figure ES.3: If BB charges work as intended 'effective' prices will increase



The rationale for including an optional five-year transitional peak-price is also difficult to fathom. If the BB charge would function in the manner described in the Third Issues Paper then, presumably, any additional peak price would be unnecessary and, worse, counterproductive. And if such a charge *would* be needed (because the BB charge *would not* work as claimed) then, logically, it should be a *permanent substitute* for the BB charge, not a temporary complementary element. In short, this element of the proposal does not make sense.

The five-year transitional peak charge does not form a coherent part of the proposal.

More generally, the proposal as a whole – and the analysis underpinning it – is unbalanced and oftentimes incoherent. We consequently continue to think that if grid users are going to face an efficient signal of the potential future costs of investments in the interconnected grid, then an *explicit ex-ante* price signal is needed. Nodal prices alone would *not* be sufficient. The additional signal might be delivered by a variant of the existing RCPD and HVDC charges, or a new LRMC charge. However, the proposed BB charge would be a poor substitute.

Consumption and investment decisions

The benefits that are forecast to flow from introducing the proposed methodology – and the BB charge in particular – would not eventuate, in practice. Instead, the inefficient BB prices might prompt load and generation to respond by making undesirable consumption and investment decisions. The proposal would also do nothing to improve grid investment processes. Table ES.2 summarises.

The BB charge could cause load and generation customers to make inefficient consumption and investment decisions.

Table ES.2: Potential inefficiencies arising from the shadow price signal

	Load	Generation
Usage	Because the key conditions for efficient shadow pricing do not hold, the BB charge would not enable Transpower to send efficient signals to customers to curtail demand when constraints start to re-emerge in the future.[29] This could result in Transpower having to invest to alleviate constraints sooner than it would otherwise have needed to if an explicit price signal had been sent to customers via the TPM.	Levying BB charges on generators would increase the costs of operating plant and, in turn their 'break-even' points. This would result in higher wholesale market prices to cover those higher costs or because of avoided / deferred generation investment. It is unlikely that those higher wholesale costs would be offset by long-term transmission cost savings because, as we note below, the BB charge would be unlikely to incentivise efficient new investment decisions.
Investment	Levying BB charges on load customers is unlikely to affect their locational decisions since, in the vast majority of circumstances, other factors would have a far greater bearing. For example, residential customers do not decide where to live based on transmission charges, and the locational decisions of large industrial customers will generally be swayed by practical factors such as the location of forests, ports, workforce, etc.	Because the key conditions for efficient shadow pricing do not hold, the BB charges would not provide generators with an efficient price signal – especially because expected private benefits are not synonymous with forward-looking transmission costs. The proposal would also send the counterintuitive signal that it is cheaper for generators to locate where assets were built before 2004. This would compromise dynamic efficiency.
Engagement in grid investment processes	If the BB charge is introduced, it is likely to create more sources of dispute and generate incentives for parties to strategically withhold information. Customers would not share future operational/investment plans if this information might then be used to assign them a higher share of benefits. The requirement to recover the costs of an investment based on estimated private benefits over the life of an investment would serve to exacerbate the scope for disputes. Customers would naturally focus on modelling assumptions that have affected them adversely. This additional unconstructive opposition could compromise dynamic efficiency if it results in 'good' investments being blocked.	

No examples of inefficient investments have been identified.

Three past investments have also been identified as being 'likely inefficient'. This is said to lend credence to the proposition that TPM reform is needed to improve the investment approval process. However, the results of the benefits modelling are

29 Note that, although inefficient load-shedding would cease in the near-term if the proposal is implemented, this would be on account of the removal of the RCPD charge, not the introduction of the BB charge – and there are many other ways to achieve that same outcome, e.g., through the introduction of a LRMC-based charge.

illogical. For example, we understand that the Authority explained at the Auckland TPM workshop that the North Auckland and Northland (NAaN) investment was estimated to have delivered *zero* benefits from 2014-2018. This implies that customers would have been no worse off if the link had been disconnected for this period. That is not plausible, as we elaborate in Box ES.1.

Box ES.1: The vSPD approach does not capture all benefits

One of the problems with the vSPD modelling approach is that it does not capture reliability and resilience benefits – especially from reliability investments. These benefits manifest when major incidents occur – they do not show up in nodal prices during 'normal' operations. The method is therefore not the right way to assess benefits. It is analogous to an airport concluding that it was 'inefficient' for it to have invested in firefighting equipment five years ago, because there had been no accidents in the ensuing period.

The allocations and prices contained in Schedule 1 are not robust.

One crucial consequence of this is that the allocations set out in Schedule 1 to the proposed TPM guideline, which Transpower would be required to apply when setting BB charges for existing investments, are not robust. All those allocations would have been afflicted by the same methodological problem, i.e., a failure to account adequately for crucial benefits arising from improved resilience and reliability. In our opinion, if BB charges are to be applied to those investments, all these allocations would need to be revisited using a more robust approach.

For the reasons set out above, the proposed approach would therefore not elicit desirable *changes* in behaviour from customers. Any benefits from the methodology would consequently need to reside in its ability to minimise distortions to demand *after* investments have been made (to improve allocative efficiency) and/or to reduce productive inefficiencies arising from ongoing disputes and so on (i.e., to improve 'durability').

Allocation of sunk costs

The Authority contends that its proposed approach would give rise to a more efficient, fairer and, consequently, more durable allocation of sunk costs. In our view, that is unlikely to be the case. It is true that any inefficient load shedding happening currently during peak periods would cease in the near-term if the proposal was implemented. However, any benefits that would flow from the resulting increase in grid use could not reasonably be attributed to the *addition* of the BB and residual charges. They would flow instead from the *removal* of the peak signal currently contained in the RCPD charge.

There is nothing the proposal would do to discourage inefficient load-shedding that more orthodox approaches could not do at least as well or better.

Indeed, there is nothing the proposal would do to discourage inefficient load-shedding that more orthodox alternatives – such as LRMC-based prices coupled with a residual charge – could not do at least as well or better. There is also little, if any, work to be done to improve the static efficiency properties of the SIMI-based HVDC charge, which would also be replaced under the proposal. On the other hand, the proposal could *compromise* allocative efficiency in a variety of ways. For example:

- when grid constraints started to re-emerge in the future the BB 'shadow prices' would not provide efficient signals to load and generation customers; and
- instead, those implicit price signals would distort the consumption decisions of those customers in the variety of ways summarised in Table ES.2.[30]

The proposal to apply DHC-based charges to the seven existing assets earmarked for BB prices is needless and would be inefficient.

The proposal to apply depreciated historical cost (DHC) based charges to the seven existing assets earmarked for BB prices would also risk compromising needlessly allocative efficiency. It would result in prices that are at their lowest right at the end of the assets' lives when they are nearly fully depreciated. This is the opposite of what efficient transmission pricing requires. There is no need to distinguish between new and existing assets in this way, because:

- there is no risk of customers 'over-paying' for the existing assets if the valuation approach switches from DHC to indexed historical cost (IHC), since there have never been bespoke prices applied to those assets, i.e., customers clearly cannot 'overpay' for something if there have been no specific prices in place;[31] and
- even if there was some reason to think that customers might 'over-pay' for particular assets (which there is not), all that would happen is that more of that revenue would be recovered via BB charges, and less through the residual, i.e., Transpower would recover the same amount of revenue overall.

The Authority is chiefly responsible for creating the uncertainty surrounding the TPM.

We consider also that the proposal would give rise to productive inefficiency. We agree with the Authority's assessment that considerable uncertainty surrounds the TPM at present, which has compromised durability and increased costs. However, in our opinion, it is the Authority itself that is chiefly responsible for this disruption. The unconventional way it has run its review and the series of radical, untested proposals that have been offered – all lacking sound economic foundations – have cast uncertainty over what was, as at October 2012,[32] quite a settled methodology.

The proposed approach would compound uncertainty, not reduce it.

The latest proposal would do little to address this uncertainty – if anything, it would make things worse. Transpower would not be able to estimate with any precision the private benefits that would transpire over the 30- to 50-year life of a transmission asset.[33] These intrinsic doubts would be a recipe for ongoing disputes as customers challenged the subjective assumptions underpinning proposed allocations. As we noted earlier, it was these very durability problems that prompted the Authority to decide against recommending the 'locked-in benefits' approach in its first issues paper.[34]

30 The optional 'transitional peak price' would not fix this underlying problem.

31 Insofar as the HVDC assets in particular are concerned, the Authority's concerns are plainly misplaced. Transpower's IPP contains a specific HVDC revenue allowance, which limits *explicitly* the amount that it is permitted to recover for those assets under the TPM.

32 This was when the Authority released the first of its Issues Papers.

33 Notably, the Authority has not attempted to forecast private benefits when determining the initial cost allocations for the seven historical investments listed in Schedule 1 of the draft TPM Guidelines. Instead, it has applied a backward-looking approach, based on 2014-18 data.

34 Electricity Authority, *Transmission Pricing Methodology: issues and proposal, Consultation Paper,* 10 October 2012, p.104.

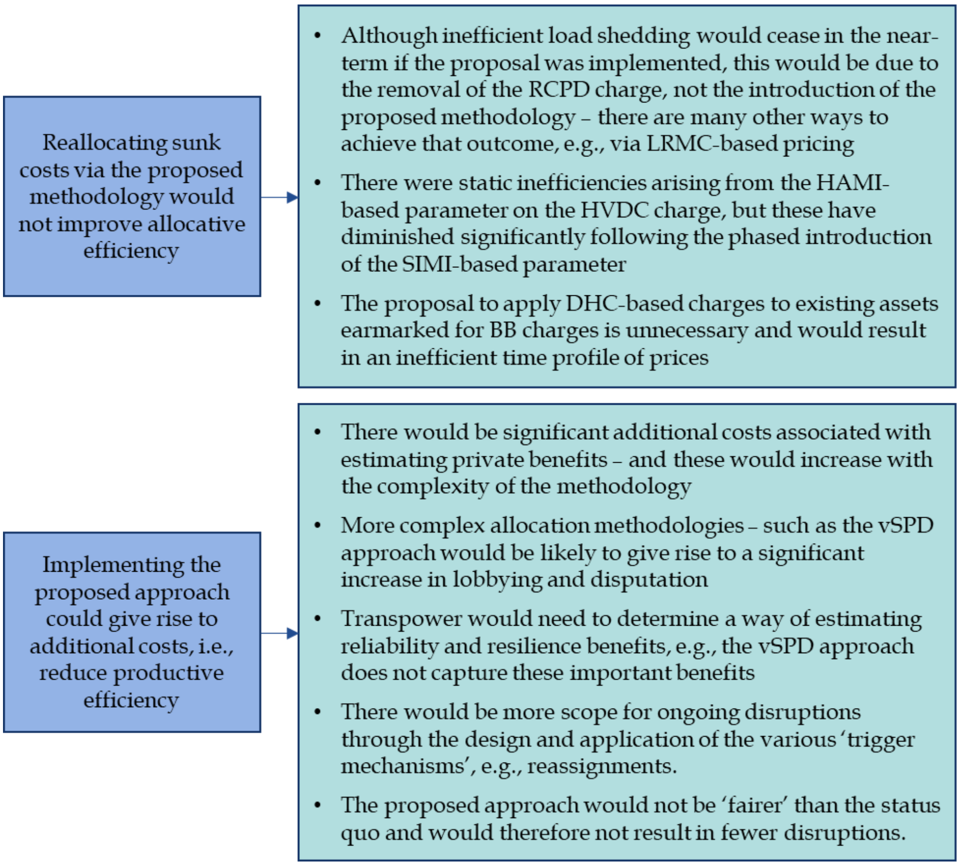
There are also more specific ways that the proposed methodology could cause further costs and disruptions. Most notably, Transpower would need to design methods for reallocating charges when large customers entered or expanded, grid usage patterns changed substantially, when there were material changes in components like the regulatory weighted average cost of capital (WACC) and when investments turned out to be white elephants. This would entail further costs and controversy. And, depending upon how these 'trigger mechanisms' were framed, customers could have incentives to change their behaviour in undesirable ways to prompt reallocations.

The proposed approach would not be clearly 'fairer' than the status quo.

Finally, we do not agree that the proposal would be unambiguously 'fairer' than the status quo – or more conventional alternatives – and therefore more durable. In our view, it is questionable whether it is 'fair' to charge customers prices based on highly imperfect estimates of the benefits they might receive over a series of uncertain scenarios over thirty or fifty years. Moreover, even if it was thought to be equitable to apply such a methodology to *new* assets, there is no logical reason to apply it to a relatively arbitrary sub-set of *existing* assets – in this case, seven.

For those reasons, we remain of the opinion that the proposal would not result in a more efficient allocation of sunk costs. Rather, changing the way in which sunk costs are allocated by implementing the proposed methodology would be likely to distort the consumption decisions of load and generation customers, compromising allocative efficiency. The approach would also give rise to significant additional costs arising from the uncertainties and disputes that would inevitably follow, i.e., productive inefficiency. Figure ES.4 summarises.

Figure ES.4: Potential effects on static efficiency



The proposal does not have a robust economic foundation. It is likely to harm dynamic and allocative efficiency.

Accordingly, like its predecessors, we do not consider that the latest proposal has robust economic underpinnings. There is no reason to think that it would provide more efficient forward-looking price signals or result in a superior allocation of sunk costs. Rather, the proposed approach is altogether more likely to compromise both static and dynamic efficiency. Furthermore, the CBA does not in any way diminish this conclusion. As we explain below, it is fundamentally flawed and consequently incapable of providing any meaningful insight into the merits of the proposed methodology.

Cost-benefit analysis

Before recommending a significant policy change, it is crucial to first gain confidence that the expected benefits are likely to outweigh the anticipated costs. Quantitative CBA is the tool that is customarily used for this purpose – especially for substantial policy changes the likes of which the Authority is proposing.[35] On its face, the Authority's CBA suggests that the proposal would deliver a substantial net benefit (**$2.7b** in NPV terms).[36] However, once one 'looks under the hood' of the modelling, that contention quickly unravels.

The CBA represents the principal 'new' piece of analysis in the consultation package. As we have seen already, the proposal itself is largely unchanged from the methodology the Authority was suggesting in December 2016. This new CBA is therefore the Authority's second attempt to supply an empirical justification for its proposal after the first – the OGW CBA – was revealed to be irredeemably flawed. Broadly speaking, the Authority has used its CBA to compare its proposal (and one alternative) to the current TPM.[37] Based on that analysis, it concludes that:[38]

Three estimation tools are used to estimate costs and benefits.

> *'…the proposal would deliver substantial benefits to New Zealand's economy and that the central estimate of **$2.7 billion** [resulting from the CBA], within the range of $0.2 billion and $6.4 billion, is a realistic estimate of net benefits.'* [our emphasis]

Three estimation tools (or 'assessment methodologies') are employed to estimate and compare costs and benefits. These are a grid use model,[39] top-down analysis[40]

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35 New Zealand Treasury, for instance, notes that 'All decisions require some kind of formal or informal CBA'. *See:* New Zealand Treasury, *Guide to Social Cost Benefit Analysis*, July 2015, p.6.

36 Unless otherwise stated, all financial values in this report are in NPV terms and 2018 dollars, consistent with those presented in the Third Issues Paper. Where we use the term 'in total' or 'in total over the period' we are referring to a simple summation of values, not an NPV. Any NPV values are estimated using the 6% social discount rate used by the Authority.

37 That is arguably not the correct approach. The Authority is reviewing the TPM *guidelines*. There are many different ways in which Transpower might change the current pricing methodology *within* the existing guidelines, e.g., by increasing the number of periods over which contributions to RCPD are measured. In other words, the CBA immediately gets off on the wrong foot.

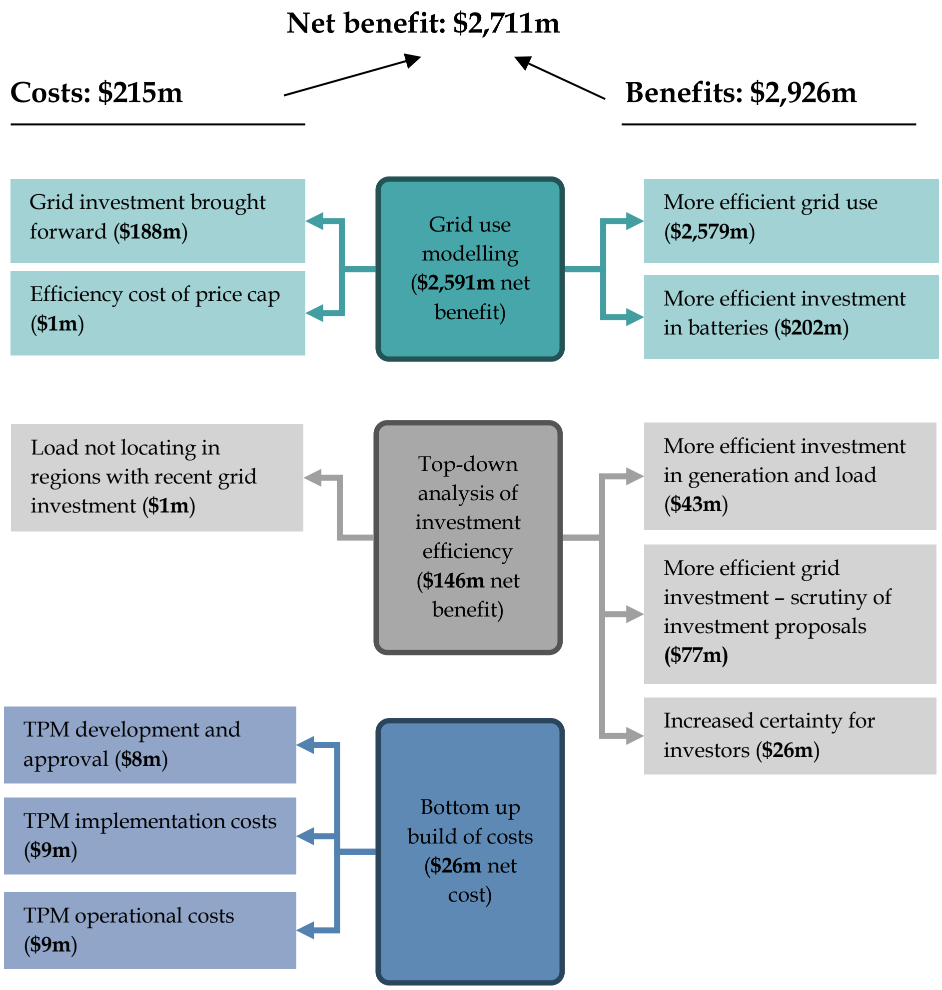
38 Third Issues Paper, p.55. Note that values are in NPV terms and 2018 dollars.

39 This is used to analyse how consumption, generation, prices and investment change in response to different TPMs and demand or investment scenarios.

40 This is used to assess how investment efficiency and certainty may change under different TPMs.

and a bottom-up build of costs.[41] Figure ES.5 summarises the benefits and costs that the Authority estimates would arise from its proposed methodology under its 'central case'.

Figure ES.5: Summary of CBA approach (central case)



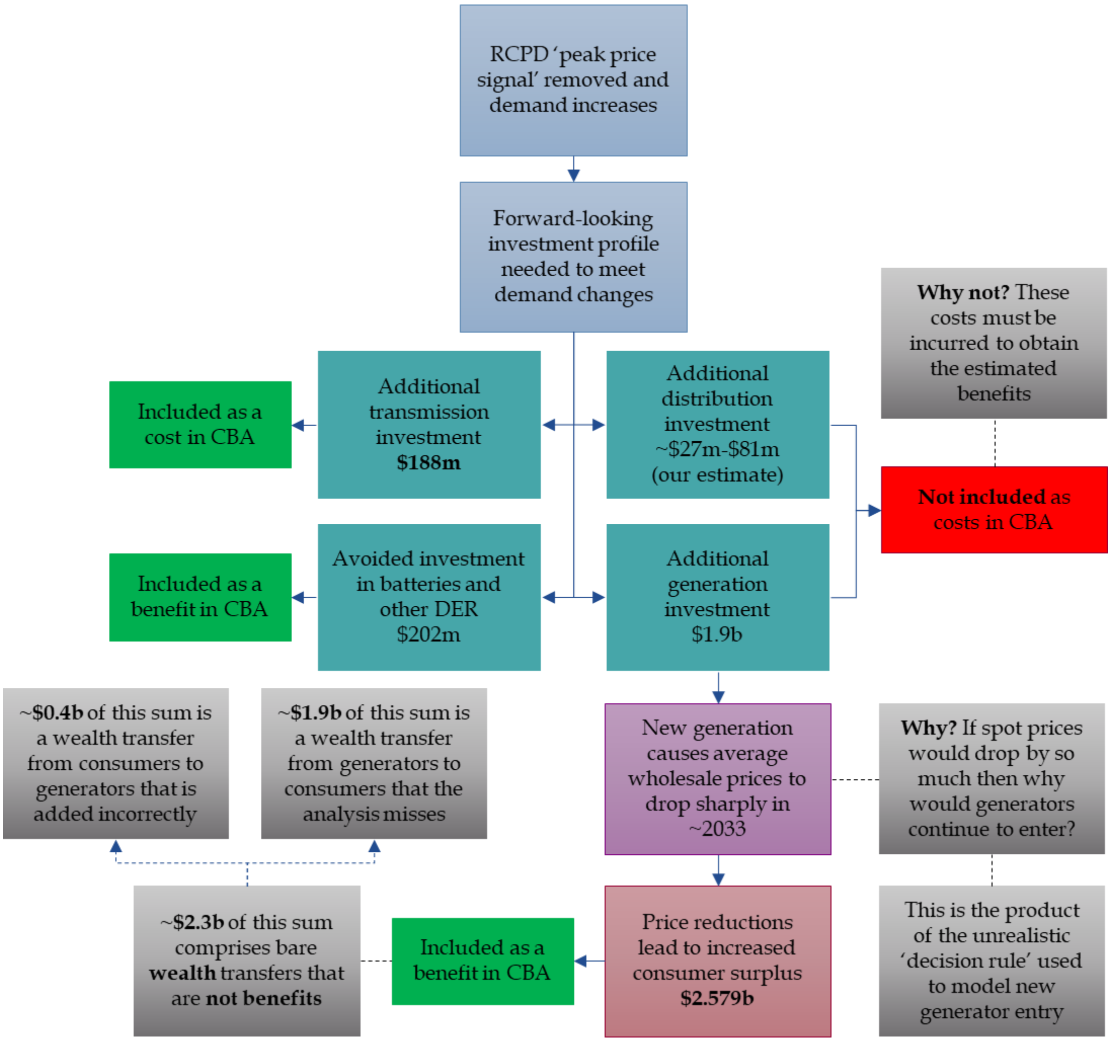
The vast majority – 96% - of the estimated net benefits are produced by the grid use modelling.

Grid use modelling

The vast majority (96%) of the estimated benefits from the Authority's proposal are produced from the grid use model. Nearly all of those benefits are said to arise from the 'more efficient grid use' that is forecast to result from the removal of the RCPD peak price signal. However, those purported benefits have no sound basis. As Figure ES.6 summarises, the modelling exhibits a series of cascading methodological errors – many of which are extremely serious – that culminate to produce a benefit estimate that is overstated by **more than $4b**.

41 This is used to estimate the costs for developing, implementing and operating a new TPM. It relied on Transpower's 2016 estimate of applying a complex TPM and the Authority's judgement.

Figure ES.6: The mechanics of the grid use model



The grid use modelling exhibits a cascading series of errors – many of which are extremely serious.

The grid use model starts by assuming that an increase in demand – particularly during peaks – would lead to a very large increase in generation investment ($1.9b, in NPV terms). That influx of new generation is assumed to drive down prices, generating a $2.6b increase in consumer surplus. Yet the model overlooks the fact that most of that increase in consumer surplus (~$2.3b of it)[42] is a wealth transfer from generators to end-consumers. Compounding matters, the model ignores nearly $2b in additional costs and fails to include 'shadow prices'.

The model assumes generators behave irrationally

The model assumes that generators ignore future prices when making investment decisions.

A key driver of the net benefit estimate produced by the grid use model is the additional grid-connected generation investment that it forecasts. However, that investment results from the application of a decision rule that makes very little sense from an economic perspective. It assumes that generators would assess the financial viability of potential investments by looking only at *past and current returns*

42 This includes both a wealth transfer from generators to final consumers ($1.9b) and a wealth transfer from consumers to generators ($0.4b) that is added back (although incorrectly).

– and for a *single year*.[43] It also assumes that new entrants would dispatch *all* of their capacity at the average dispatched per MW price. That does not comport with reality and is at odds with efficient investment decision making. It is unrealistic to assume that *all* capacity would be dispatched at all times in a competitive wholesale market with variable wind and hydro availability.

Like in any market, entry decisions would be based on one principal factor: *projected future cashflows*.[44] To that end, one of – if not the single – most important matter that a firm would consider before investing in new generation is *future* wholesale prices (net of transmission charges). If a generator anticipated that its entry – and/or entry/expansion by others – would lead to a sharp reduction in nodal prices, or if it expected that it would be dispatched infrequently, then it would be disinclined to invest. The grid use model overlooks these crucial facts, which gives rise to a counterintuitive outcome; namely, the model predicts that:[45]

Generators are forecast to be worse off to the tune of $5.8b in NPV terms under the proposal.

- generation investment would increase by $3.8b in total over the 2020 to 2049 period; while
- wholesale market revenue (net of interconnection charges) would *fall* by $13.2b.

Collectively, in NPV terms, generators would be worse off to the tune of $5.8b under the proposal according to the model – with reductions in revenue accounting for $3.9b of that sum. There is therefore a striking divergence between the amount that generators are assumed to invest under the grid use model and their steadily dwindling returns, as Figure ES.7 highlights. In our opinion, it is inconceivable that all of this additional investment would be financially viable. It is inevitable that at least some of it – and probably a large proportion – would be unprofitable.

Much of the new investment driving the forecast spot price drops would not happen.

The unrealistic generator entry decision rule has caused the Authority to conclude that the introduction of its proposal would cause generators to happily invest very large sums while ignoring the consequences for wholesale prices and *expected* returns. In reality, much of that investment *would not occur*. Accordingly, the wholesale price reductions that are driving 96% of the Authority's net benefit estimate would not happen either. And, without those price reductions, the $2.6b benefit from more efficient grid use would disappear.

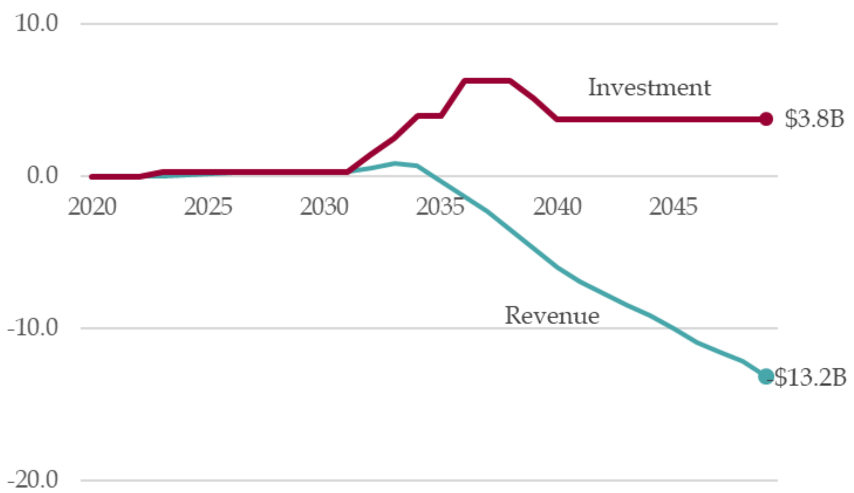
43 This is confirmed by inspecting the Python code used to implement the decision rule in the grid use model.

44 *See for example:* Copeland, Weston and Shastri, 2005, *Financial Theory and Corporate Policy*, Fourth Edition, p.18, where the authors explain that 'the objective of the firm is to maximize the wealth of its shareholders…[which is] more carefully defined as the discounted value of future cash flows'.

45 Both values are in total dollar terms. Note that the $1.9b in additional generation investment referred to earlier was in NPV (discounted) terms. In other words, generation investment increases by $3.8b in *total* over the 2020 to 2019 period relative to the status quo, and by $1.9b in *NPV terms*.

Figure ES.7: Comparison of cumulative generator revenue and investment cost differences (proposal less status quo) ($b, $2018)[46]

The model assumes that generators would invest large sums while ignoring the impacts on prices and returns.



Most of the estimated benefit is a wealth transfer

Having assumed – erroneously – that its proposal would lead to a wave of new generation and lower prices, the Authority then makes a second error. It assumes that the resulting efficiency gain from 'more efficient grid use' is equal to the benefits that *final* consumers derive from those lower prices. It is not. The Authority has inadvertently conflated changes in final consumer surplus with changes in allocative efficiency. These are *not synonymous*.

Figure ES.8 highlight this problem. The equation at the top is a simplified version of the consumer surplus calculation used by the Authority to determine its central CBA net benefit estimate (equation 10 in the Technical Paper). The chart beneath it is a stylised representation of what happens to consumer surplus when there is a movement *along* the demand curve (i.e., an increase in quantity demanded, following an outward shift of the supply curve).

In the figure, the supply curve shifts outwards, which leads to an increase in the quantities supplied and demanded and a reduction in the market-clearing price. There are two effects from the reduced price. First, some surplus is shifted from generators to final consumers, i.e., a transfer of 'generator surplus[47]' to 'final consumer surplus' (see the blue rectangle). Second, some new consumer surplus is

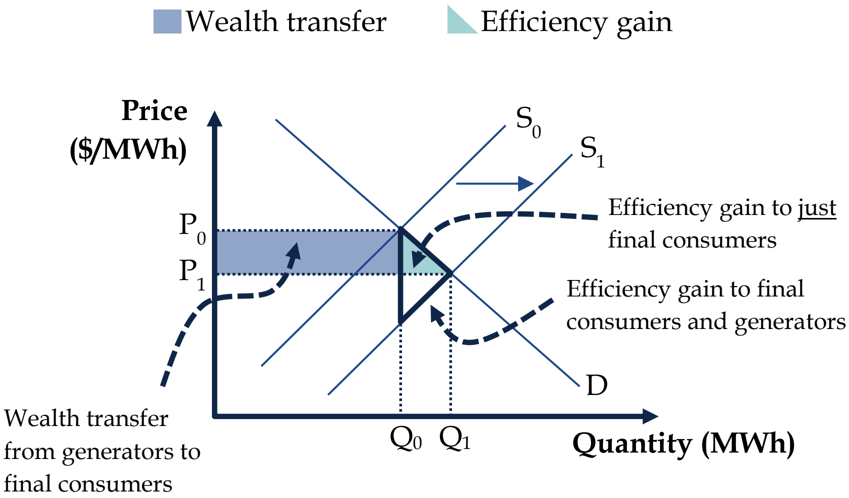
[46] Data are sourced from the 'AOB.csv', 'RCPD.CSV' and 'generation_investment.csv' files for the 'All_major_capex' scenario. Generator revenue is calculated for a given year by multiplying the quantities for each backbone node and time period by the corresponding generator price and summing these together. A net revenue value is obtained by subtracting the interconnection charges faced by generators.

[47] Note that 'generator surplus' is not 'producer surplus' in the traditional sense, since generators are also consumers of transmission services.

generated that is not taken from anyone else, i.e., a reduction in 'deadweight loss' (represented by the green triangle).[48]

Figure ES.8: Measuring consumer surplus with a shift along the demand curve

$$\Delta CS = \underbrace{-Q_0 \times (P_1 - P_0)}_{\text{Wealth transfer}} - \underbrace{0.5 \times (Q_1 - Q_0) \times (P_1 - P_0)}_{\text{Efficiency gain}}$$



Changes in consumer surplus contain both bare wealth transfers and changes in deadweight loss.

The transfer from generators to final consumers arises because of the reduced prices that final consumers pay for electricity that they would have consumed anyway at the higher price. It comes entirely at the expense of generators who receive those now lower prices. This does not produce any *additional welfare* that did not previously exist – it is a bare transfer of current wealth. It is for that reason that the Authority has said it does not account for transfers in its decision making (despite doing precisely that in its CBA, as we shall see shortly).

Transfers do not result in any additional welfare, whereas reductions in deadweight loss create new wealth.

In contrast, the reduction in deadweight loss (represented by the green triangle) clearly *is* a benefit. At the lower price, there is additional demand for electricity that *did not happen* at the previous, higher price. Provided that demand can be served at a price that generators are willing to accept and that final consumers are willing to pay *new wealth* can be generated. In other words, it is possible to make some people better off without making others worse off. Regrettably, the Authority has failed to make this crucial distinction in its grid use model.

The Authority has mistakenly included $1.9b in transfers from generators to final customers in its net benefit estimate.

Instead, the equation the Authority has employed measures the *total change* in consumer surplus. It has therefore mistakenly included the 'wealth transfer' from generators to final consumers (represented by the blue rectangle) in the estimated net benefit. This has caused it to overstate dramatically the benefits that would flow from more efficient grid use. In our assessment, the wealth transfer component of the change consumer surplus accounts for around 73% or $1.9b of the ~$2.6b estimated benefit from more efficient grid use.[49]

48 If total welfare gains were being measured, then the entire area of the bolded dark triangle outline would be captured.

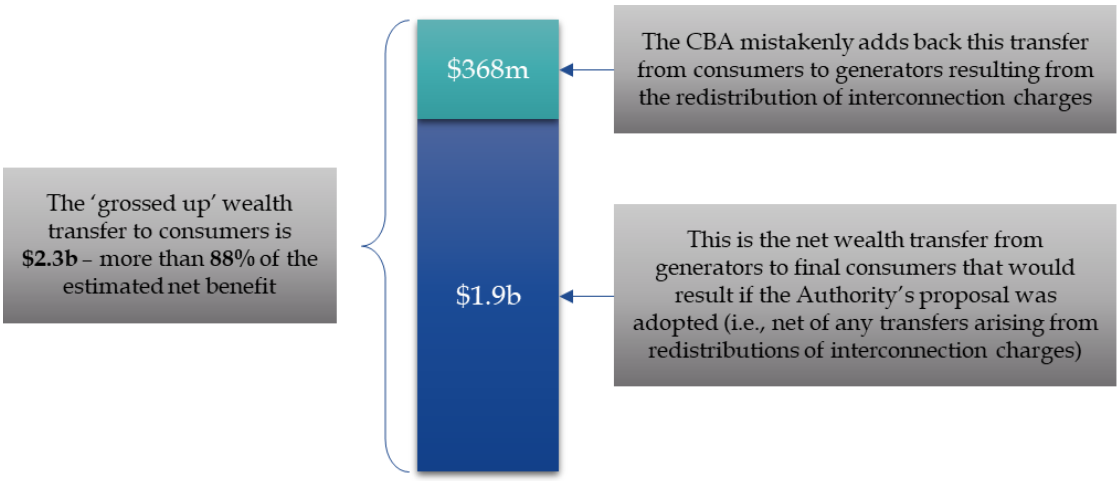
49 The details of this calculation – which is not straightforward – are set out in section B.1.3.

The Authority then compounds its error by adding needlessly another $368m to the net benefit estimate.

Exacerbating matters, the Authority also *adds back in* $368m in wealth transfers from consumers to generators. It does so because it presumably thinks that this sum has been included as a cost elsewhere in the CBA and that an offsetting adjustment to 'benefits' is therefore needed so that it 'nets out' to zero. However, the transfer *is not* treated as a cost anywhere else.[50] The needless adjustment therefore inflates the net benefit estimate by a further $368m, bringing the total sum of inappropriate wealth transfers to ~$2.3b, or to 88% of the estimated benefit from more efficient grid use. Figure ES.9 illustrates the compounding effect of these two errors.

Figure ES.9: Grossing up the wealth transfer benefit to consumers (not to scale)

All told, wealth transfers account for ~$2.3b or 88% of the net benefit estimate.



Given that the Authority went to the effort to account for this second wealth transfer – albeit erroneously – it is difficult to understand why it did not endeavour to make some kind of adjustment when measuring the change in consumer surplus. After all, that calculation has substantially more bearing on the overall net benefit estimate. Strangely, at one point in its paper, the Authority contends that the reduction in nodal prices predicted by its grid use model would *not* give rise to a wealth transfer from generators to final customers. It offers a curious rationale:[51]

It is not possible for nodal prices to fall without existing generators losing out to end-consumers.

> *'Generators would not lose out to consumers, because, in the model, the falling prices are a result of generators expanding efficiently in response to increased demand and prices that justify the expansion. The expansion benefits both generators and consumers.'*

This explanation is not credible. Lower wholesale prices cannot benefit both the customers that are paying them *and* the generators that are receiving them. It is possible that some *new* generators might be better off, i.e., because they enter and earn at least a normal economic profit.[52] However, if that new entry causes

50 It may be that the Authority assumes that the change in consumer surplus (of $2.3b) would be higher if consumers did not end up paying more of the interconnection charges. That is likely true. However, backing out that change would simply increase the wealth transfer component of the change in consumer surplus, which should not be included as a benefit in any case.

51 Third Issues Paper, p.32.

52 However, the analysis set out in the previous section suggests that even *new* generators – i.e., those that enter in response to the modelled increase in wholesale prices – would often struggle to earn a reasonable return on their new investments. That is because of the aforementioned 'generation entry decision rule' which assumes that generators would invest without paying any attention to the potential impacts upon future spot prices.

wholesale prices to fall then, by definition, all *existing* generators would be unambiguously *worse off*. Money they would have earned at the higher wholesale price would flow to final customers, resulting in a very large wealth transfer. Figure ES.10 illustrates this point.

Figure ES.10: Comparison of wealth transfer to generator revenue change ($billion, $2018)[53]

Wealth transfers are driving the benefit estimate.

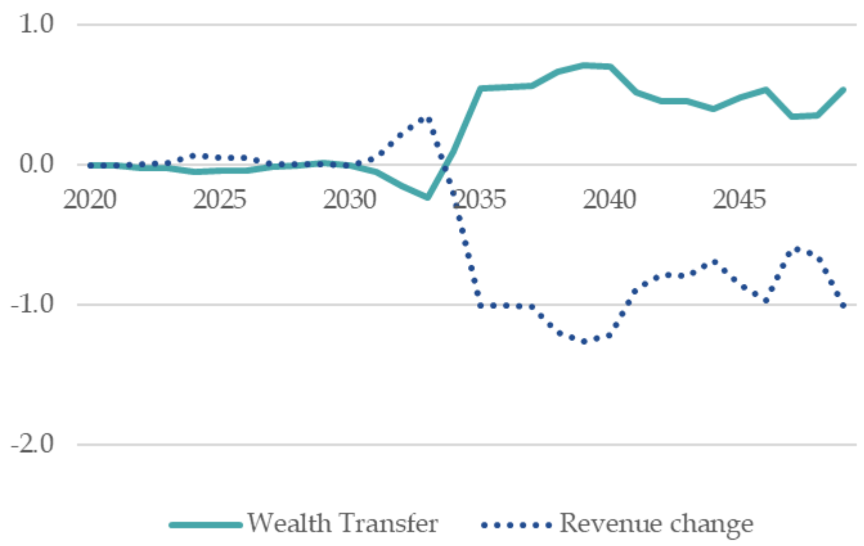


Figure ES.10 compares the wealth transfer from generators to final consumers to the change in generator revenue. Unsurprisingly, the two curves are almost perfect mirror-images of one another. Higher wealth transfers from generators to final consumers correspond to lower revenues to generators, and vice versa. The two curves even cross the horizontal axis at the same point. Put simply, the lower wholesale prices are disadvantaging existing generators and resulting in enormous bare wealth transfers to final consumers. That is what is driving the benefit estimate.

Costs from meeting the higher peak use are ignored

The grid use model assumes that the removal of the peak price signal would lead to an increase in demand – particularly during peak periods. To manage this increase in peak demand, additional investment would be needed in Transpower's transmission network, distribution networks and grid-connected generation. The CBA picks up the first of these as a cost – which it estimates to be $188m[54] – but ignores the other two. In the case of **distribution** costs, the Authority notes that:[55]

53 Data are sourced from the 'AOB.csv', 'RCPD.CSV' and 'CS_results.csv' files for the 'All_major_capex' scenario. Generator revenue is calculated for a given year by multiplying the quantities for each backbone node and time period by the corresponding generator price and summing these together. A net revenue value is obtained by subtracting the interconnection charges faced by generators.

54 In our opinion, this additional transmission investment cost is likely to be closer to $370m, for the reasons that we set out in Appendix B.5.4.

55 Third Issues Paper, p.46.

'The CBA does not include any costs for distribution network investment brought forward. ***This is because the focus of the CBA is transmission, not distribution****. Accordingly, we have not evaluated either the incremental costs or the incremental benefits associated with the distribution network.*

On the benefit side, we have valued consumption at the price paid at the grid exit point (GXP), rather than the price paid at the customer's point of connection on a local network. This approach excludes the additional consumption benefits relating to the value that consumers place on the distribution network. The Authority is aware that most distribution networks around New Zealand have spare capacity. ***It follows that incremental distribution costs of the proposal are likely to be low, and in the Authority's view, are likely to be exceeded by the incremental benefits associated with the distribution network****.'*

Additional distribution costs are clearly relevant to the CBA and should be included.

This is a very odd statement. The contention that the focus of the CBA is 'transmission' and that distribution costs can therefore be ignored is incorrect. The focus of the CBA is *not* on 'transmission' – it is on the costs and benefits that arise from a *proposed change in the TPM*. Consequential impacts on distribution networks are plainly part of that equation. Indeed, aspects of the CBA model clearly incorporate costs and benefits that are not elements of the transmission network – such as batteries, generation investments (in the top-down modelling), and so on. The Authority's statutory objective also refers to the electricity *industry*, not just sub-components of it.[56]

Distribution costs make up around 27% of consumers' bills – more than twice as much as the transmission component (10.5%).[57] Moreover, distribution network expenditure is influenced heavily by the need to manage peak demand. Increased peak demand leads to more investment and, in turn, higher consumer prices. Ignoring the impact that elevated peak period consumption would have on the distribution cost component of final customers' bills consequently undermines the usefulness of the CBA.[58]

As a conservative indication of this potential impact, the higher peak consumption forecast over the 2020 to 2049 period corresponds roughly to a 1,388MW increase in ratcheted peak demand at the backbone node level.[59] Assuming that the LRMC of

56 *See: Electricity Industry Act 2010*, section 15.

57 See, for instance, Electricity Authority, 2018, *Electricity in New Zealand*, p.13.

58 The Authority's claim that most distribution networks in New Zealand have spare capacity is not credible either. Certainly, some areas of some networks will have spare capacity. But that cannot be the case everywhere on every network. If it were, then there would be no need for networks to forecast – and for the Commission to allow – augmentation expenditure as part of their default price path allowances. It would also be at odds with the Authority's own attempts to make distribution prices more cost-reflective. If no costs were associated with additional peak demand, then such reforms would not be needed.

59 This is calculated using the peak period quantity forecasts in the 'AOB.csv' and 'RCPD.csv' spreadsheets for each year and backbone node, converting them to an average MWh per hour (by dividing them by the 800 hours of peak period per year, or 1,600 30-minute trading periods). This simplification is conservative because, in practice, peak demand is not constant across the peak period, and is likely to be higher. Using peak 'observed' demand, ratcheted demand for a given year is calculated as the maximum observed demand for all years up to and including that year. If there is a drop in observed demand, then ratcheted demand does not change from the prior year. Ratcheted demand is used because it drives network investment.

distribution network peak demand is between $50–$150/kW,[60] this would correspond to around $27m to $81m in additional expenditure over the period. This is a very significant amount given the size of some of the other costs and benefits that have been included in the CBA.[61]

In the case of **generation**, the grid use model predicts that an additional $1.9b of investment would occur if its proposal went ahead.[62] Clearly, that is a very large sum. However, the CBA model includes only the benefits of that investment, not its cost.[63] The Authority offers the following rationale for that approach: [64]

The fact that the generation market is supposedly competitive is irrelevant.

> *'The CBA does not include any costs for generation investment brought forward. This is because the generation sector is assumed to be competitive, so any generation investment that occurs as a result of the proposal is assumed to be efficient investment.'*

This explanation is again unsatisfactory. Even if the wholesale market is effectively competitive, it does not follow that every investment decision made by generators is 'efficient'. Generators respond to the price signals that they are given. If the TPM supplies them with the 'wrong' signals, then the result could be inefficient investment outcomes. Indeed, the Authority has spent the last seven years explaining why, in its opinion, the current TPM does *not* produce efficient generation investment outcomes.

The Authority is assuming something that it should be testing.

What the Authority is *really* saying here is that the additional generation expenditure can be disregarded *in this instance*, because it would be happening in response to *its preferred proposal*. That $1.9b in additional expenditure can therefore be *presumed* to be efficient and safely omitted from the CBA. The circularity in this logic should be self-evident: the analysis starts by assuming that the methodology being examined is efficient and then characterises everything that flows from it – even additional costs – as 'good'. This is no way to perform a CBA.

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60 See, for instance, Orion, 22 February 2019, *Methodology for delivering our delivery prices (from 1 April 2019)*, p.55, which includes an LRMC estimate of $107/kVA (or ~$86/kW assuming a power factor of 0.8). Various Australian electricity distributors report LRMC estimates of $56/kW to $119/kW for residential customers; *see for instance*: Jemena Electricity Networks, 20 September 2017, *Tariff Structure Statement 2016*, p.E-7; and Ausgrid, April 2019, *Tariff Structure Statement*, p.64. At an exchange rate of NZ$1.06 per AU$1, this equates to a range of $60–$126/kW.

61 We note that the Authority has claimed that any such distribution costs would be 'more than offset' by incremental benefits. However, it is not at all obvious what benefits the distribution networks themselves would obtain, if any. Moreover, the benefits to consumers (e.g., from increased consumption during peak periods) are already factored into the CBA (i.e., they are wrapped up in the $2.6b estimate). The Authority provides no explanation as to what those benefits might entail. In our opinion, the most likely reason for this is that they do not exist.

62 This is calculated by comparing the investment values reported in the 'generation_investment.csv' spreadsheet for the 'All_major_capex' scenario.

63 Although the Authority attempts to discount these benefits by averaging consumer surplus changes with and without energy price effects, it nevertheless includes some benefits.

64 Third Issues Paper, p.47.

Even if the additional investment would be efficient it still comes at a cost that must be included in the CBA.

Even if the additional generation *would be* efficient (which does not seem plausible[65]), it would still come at a substantial cost. The fundamental idea of the CBA is to test whether those costs are outweighed by the benefits, i.e., to measure *both* – not to include one and disregard the other. At the moment, the approach is unsound, because it is:

- measuring the supposed benefits of the new investment in generation including:
  - the increase in consumer surplus arising from the lower estimated wholesale prices (most of which is a bare wealth transfer, i.e., not a benefit); and
  - the avoided costs of investments in batteries and DER; but
- not counting the cost of the investment that is needed to give rise to those purported benefits, i.e., including the $1.9b in additional generation.

The CBA is measuring the forecast benefits arising from the new generation, but not the cost of it.

This treatment of benefits and the costs that give rise to them is therefore biased. The Authority's approach is analogous to measuring the net benefit that a child derives from a new car as the satisfaction she gets from it plus the avoided cost of bus fares, while ignoring what her parents or guardians had to pay for the vehicle in the first place. In other words, even if the additional $1.9b of generation investment was 'efficient' (which does not seem credible), it must still be included as a cost in the CBA.

The model also disregards other costs likely to be associated with increased peak demand, such as any increase in **carbon emissions**. There is growing concern about the emissions that are produced during peak periods. There has also been increasing recognition of the gains that could be made from reducing peak consumption. For example, the Energy Efficiency & Conservation Authority noted recently that:[66]

The Authority has stated that carbon costs are important, but they have not been considered.

> *'Reducing electricity demand at peak times is again shown to be a key opportunity for New Zealand to limit the need for more electricity infrastructure spending, and reduce emissions.*
>
> *A [Concept Consulting] report commissioned by the Energy Efficiency and Conservation Authority (EECA) shows cutting peak demand on winter evenings would have the biggest impact, as this eases pressure on electricity lines networks and expensive, carbon-intensive peaking generation.'*

The Authority explicitly ignores 'health or environmental policy objectives and outcomes' in its CBA.[67] However, that does not make them any less important to the New Zealand economy or to electricity consumers. In our opinion, those costs *should* be considered when assessing what changes should be made – if any – to the TPM. Indeed, the environmental costs of carbon emissions are just as important as the costs of investment in distribution networks and in generation.

[65] In our opinion it is highly unlikely that the $1.9b in new generation investment *could* reasonably be characterised as 'efficient'. In fact, it would be unlikely to transpire, in practice, for the reasons we provided earlier.

[66] Energy Efficiency & Conservation Authority, 29 March 2018, *Big benefits from reducing peak energy use*. Available: here.

[67] Technical Paper, p.9.

The model does not reflect the actual proposal

We explained earlier that a key function of the proposed BB charge is to provide an implicit forward-looking 'shadow price' signal. However, these 'shadow prices' are nowhere to be seen in the grid use modelling. If the modelling did incorporate these shadow prices – which are a core feature of the methodology – then the results would inevitably differ significantly from those published by the Authority. Moreover, given all of the problems with the underlying economic theory, it is safe to assume that the impact would be negative.

Shadow prices do not feature in the grid use modelling. If they did, the results would be completely different.

As it is, all that we can say for certain is that because shadow prices are an important part of the Authority's proposed methodology, it has not actually modelled its own proposal. This effectively renders this aspect of the CBA – which accounts for the vast majority of the estimated net benefit – irrelevant. At best, it is examining the merits of a proposal that is not even 'on the table'. And, for the reasons set out in previous sections, the benefit estimate that the grid use model has produced for that irrelevant proposal is unreliable.

The model would produce the same answer for multiple options

The grid use model not only neglects to reflect the methodology that the Authority has actually suggested, it would also predict largely the same outcome for *any number* of alternatives. Provided that an approach is comprised *solely of fixed charges*, the grid use model would produce the same $2.6b benefit. There is no need for those fixed charges to be based on an estimate of private benefits. For example, the following methodologies would perform equally well:

The grid use model would produce the same net benefit estimate for virtually any approach comprised solely of fixed charges.

- replacing the RCPD and HVDC charge with a single non-distortionary broad-based tax comprising only fixed charges, i.e., something akin to the proposed residual charge; or
- as implausible as it may seem, replacing the RCPD and HVDC charges with a purely random allocation of fixed charges, i.e., where customers' annual fixed dollar sums were drawn out of a hat.

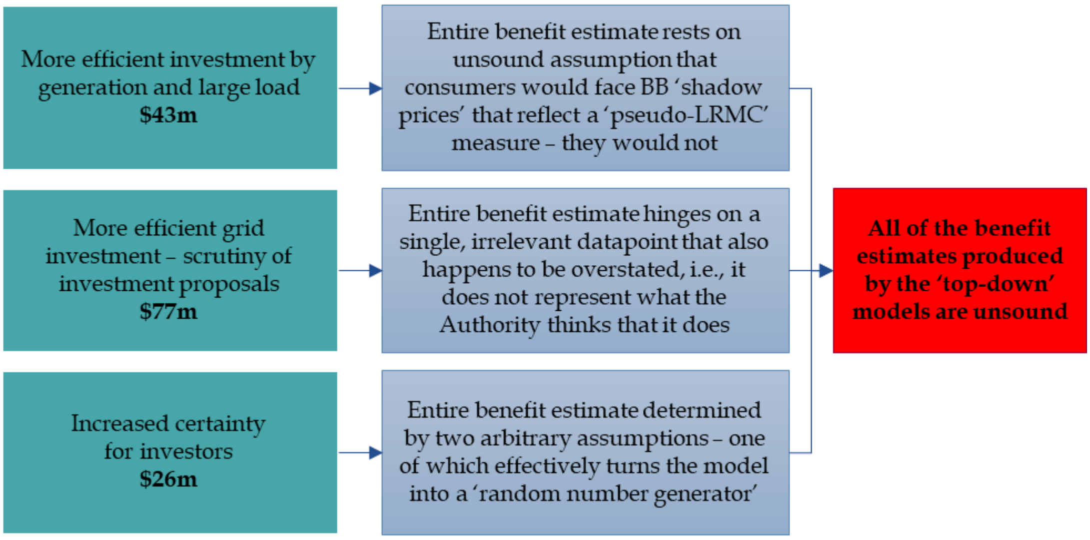
In other words, even taking the grid use model as given with its many flaws, the benefit estimate that it produces is *not* uniquely attributable to the Authority's proposal. What the model has *really* estimated is a benefit (albeit an erroneous one) that could be obtained by replacing the RCPD charges with almost any variant of fixed charging. This is not symptomatic of robust modelling – particularly given the absurdity of the methodology described in the second dot point.

Top-down modelling

Top-down analysis is used to estimate the smaller and more bespoke costs and benefits. The three main categories of benefits are 'more efficient investment in generation and large load' ($43m), 'more efficient investment from greater scrutiny' ($77m) and 'increased certainty to investors' ($26m).

Figure ES.11: Problems with the top-down modelling

Top-down analysis is used to estimate the smaller and more bespoke costs and benefits.



As we explain in the following sections, and as Figure ES.11 indicates, all of these estimates are produced using deeply flawed methodologies and inputs. Consequently, none of these benefits estimates are robust.

More efficient investment in generation and load

The model includes shadow prices – but the wrong ones. Those price signals would not reflect LRMC.

The 'top-down' analysis assumes that generators and large loads would respond to expected *future* BB charges by reducing or shifting their generation and consumption to areas where the transmission network has more capacity, thereby reducing investment needs. However, those 'shadow-prices' do not reflect the signals that customers would actually face. They are instead based on a simplistic measure of LRMC[68] which, as we explained earlier, is wrong. In reality, the implicit price signals sent by the BB charge would be:

- impossible for all but the most sophisticated of customers to discern, even assuming they were inclined to respond to them; and
- *not* cost-reflective, i.e., BB shadow price signals would only resemble LRMC by sheer coincidence.

In other words, although the Authority has attempted in this model to replicate something resembling its own proposal by including shadow prices of a sort (unlike in its grid use model – discussed above), it has failed. Under the Authority's proposal, customers would face bespoke shadow price signals that reflected the benefits they perceived they would receive from an investment – and those signals

[68] Specifically, the Authority assumes that increases in peak demand give rise to additional transmission investment. It calculates this rate of incremental investment expenditure each year as: forecast incremental network expenditure in that year *divided by* the change in peak demand between the previous year and that year. This approach gives rise to estimates of expenditure per additional MW that vary from $178,822 (in 2026) to $2,895,453 (in 2032), taken from the example calculation in the 'Efficient investment' sheet of the 'Investment efficiencies model.xlsx' file. These are somewhat like pseudo LRMC estimates, calculated using only a year of expenditure and demand growth. These are the 'shadow price signals' to which customers are assumed to respond. They bear no resemblance at all to the *actual* price signals that would be provided by a BB charge.

would *not reflect LRMC*. This would cause load and generation to respond by making *inefficient* consumption and investment decisions.

Greater scrutiny of investments

The Authority has assumed that $77m in benefits would be obtained by consumers facing BB charges subjecting Transpower's investment proposals to greater scrutiny. We explained above why there is no reason to think that there is a problem with the Commission's grid investment approval process that needs solving. We also set out why the Authority's proposal would be likely to *compromise* those proceedings. The Authority's CBA does not establish otherwise.

There is no sound basis to think there are any benefits on offer from 'greater scrutiny of investments' by customers.

For starters, the Authority relies on just a single observation. Namely, it notes that the Commission reduced Transpower's proposed enhancement and development (E&D) base capex projects allowance by 4.4% between the draft and final determinations for the second regulatory control period (RCPD2).[69] From this one datapoint, the Authority assumes that it can apply efficiency factors of 4%, 2%, 1% or 0% to Transpower's proposed capex over the 2022 to 2049 period, depending on the type of expenditure. This is problematic, because:

- the entire analysis hinges on a single observation, which is inherently risky in the best of circumstances – and even more so when it is being used to project benefits out to 2049;
- the 4.4% reduction followed scrutiny from *the Commission*, not *customers*, i.e., it is not a relevant metric because the Commission will be able to perform a similar oversight role for *future* transmission proposals – the reduction was not achieved because BB charges were in place (because they were not);
- the *pertinent* question is whether reductions were on offer *above and beyond* those identified by the Commission, which seems highly unlikely if not implausible, i.e., the Commission is in the best position to identify potential efficiencies; and
- it is also possible that the Commission got its decision wrong – regulators and their advisors can and do make mistakes, which is one of the many reasons why it is imprudent to base an entire analysis on a single observation (and, in this case, on an irrelevant one).

The entire analysis is based on a single, irrelevant datapoint.

Perhaps even more problematically, the Authority appears not to have realised that its model assumes implicitly that the additional 4.4% that Transpower was proposing to spend would not have delivered *any benefits at all*. That assumption is not appropriate. It is virtually impossible to conceive of any scenario in which that additional capital expenditure would have delivered *zero* benefits. In reality, the Commission presumably determined that the additional investment would not have delivered benefits that were sufficient to justify the cost (not that there were *no benefits* to speak of).[70]

69 Third Issues Paper, p.42.

70 To use a simple example, if Transpower was proposing to spend $1,000 (to use a round number), the Commission might have determined that $44 of that sum would deliver only $40 in benefits

Not only is the single datapoint irrelevant, it is also inflated inadvertently.

In other words, even if the 4.4% datapoint upon which the Authority has based the entirety of this modelling was relevant (which it is not), it is *clearly the wrong number*. The *true* efficiency gain would likely be many magnitudes smaller than 4.4% and, by extension, the percentages that the Authority has adopted are also likely to be overstated substantially. As such, even on its own terms, the $77m estimated by the model is artificially inflated – most likely considerably.[71]

Reduced uncertainty for investors

It is unclear whether this category of benefits should even be included in the CBA.

The top-down modelling assumes that investors would benefit from reduced uncertainty if the Authority's proposal was implemented – to the tune of $26m. There is no doubt that reduced policy uncertainty can lead to economic gains.[72] However, in this case, any improvements would stem primarily from clearing up the uncertainty created by the Authority's own review, which has fallen short of best regulatory practice in numerous respects. This strikes us as an odd – and arguably self-serving – source of benefits to include in a CBA.

There are many potential ways to improve certainty for investors – but the proposed methodology is not one of them.

In this particular instance, improved durability could be obtained far more simply by the Authority stating categorically that it will be stopping its review and not contemplating any changes to the TPM for the next, say, ten years.[73] In contrast, it is highly unlikely that the proposed option would do much – if anything – to reduce uncertainty.[74] These practical realities are ignored in this aspect of the CBA modelling. On its face, the model appears to be very sophisticated. However, when the elaborate computer code is stripped away it becomes apparent that the results are driven primarily by two crucial inputs; namely:

- an assumption that the proposed TPM would defer the frequency of 'uncertainty' events (i.e., a major review of the methodology) from 1 every 10 years to 1 every 11 years; and
- the selection of '100' as the benchmark level of uncertainty – which is an assumption that is required to translate the top-down modelling framework into a benefit estimate.

and cut the allowance to $956. However, in this stylised example, the efficiency gain is not 4.4% ($44 ÷ $,1000), it is *0.4%* ($4 ÷ $,1000).

71 The model also does not take into account the additional costs that Transpower, the Commission and stakeholders would incur as a result of that additional scrutiny. If the Authority's theory is to be believed, all parties would need to prepare or engage with additional material and participate throughout the process, relying on internal resources and often external support. None of these costs have been factored into the analysis.

72 Third Issues Paper, p.44.

73 Or, alternatively, certainty might be achievable if the Authority proposed a more economically orthodox reform option, such as an LRMC-based pricing option – a candidate suggested by several parties throughout the review.

74 Substantial uncertainty would surround the estimation of benefits, the durability of those charges over time, the scenarios in which they would be revisited and, ultimately, the durability of the regime. In our opinion, there is a very good chance that these problems would render the methodology unsustainable and prompt major changes to be made to the near-term to make it more workable.

The modelling hinges primarily on two arbitrary assumptions that have no empirical foundation.

There is no objective empirical basis for either of these inputs. As for the first assumption, no analysis is presented to justify the selection of the 10- and 11-year periods. They are guesses. Changing those intervals has a substantial impact on the estimated benefit. For example, if one assumes instead that the proposal would lead to an 'uncertainty event' once every 21 years instead of every 20 years, the estimated benefit drops to around $15m. It is alarming that the result is so sensitive to such a spurious assumption. The second input is even more worrisome.

The second assumption undermines completely the efficacy of the modelling. In order to produce a benefit estimate, the model must assign a baseline 'value' to uncertainty. Ideally, the benefits estimate would not hinge upon that number. After all, it is a purely random baseline value – it is not something that *can* be quantified. In other words, it should not matter whether the model uses 1, 100, 1,000 or 1,000,000,000 for that 'baseline' value. Each of those equally viable candidates should yield *the same answer*.[75]

It is not exaggerating to say that this model is little more than a random number generator.

But they do not. The Authority picks a baseline value of 100 – as good a selection as any other – and this produces a benefit estimate of $26m. However, if it had picked 1,000 – a no less viable candidate – the benefit would have been more than 10 times higher, at over $260m.[76] And if it had selected a baseline value of 1 – which, again, is no more 'right or wrong' than any other number – the benefit estimate would be nearly zero. This problem is fatal to the model's credibility. It is no exaggeration to state that the model is little more than a random number generator.

Time pattern of net benefits

The time-profile of the Authority's net benefit estimate is very peculiar. Figure ES.12 below illustrates the cumulative NPV of the net benefits forecast to arise from the Authority's proposal over time. The green line is simply the result that comes out of the Authority's CBA – with all the errors described hitherto still in play. It shows that, even with all those mistakes left unaddressed, the projected net benefit is *virtually zero* up until around 2034. Then, at that twelve-year mark:

- an influx of new generation is forecast to take place (unrealistically, for the reasons described earlier);
- forecast wholesale prices drop sharply (a wholly predictable outcome that generators are assumed to ignore); and
- from that point forward, net benefits grow steadily (remembering that almost all of this a bare wealth transfer and therefore not an efficiency benefit at all).

The dotted blue line shows what happens to the NPV of net benefits if the modelling is adjusted to address two of the more obvious errors – namely, to *exclude* the $2.3b of wealth transfers and to *include* the $1.9m of additional generation costs.

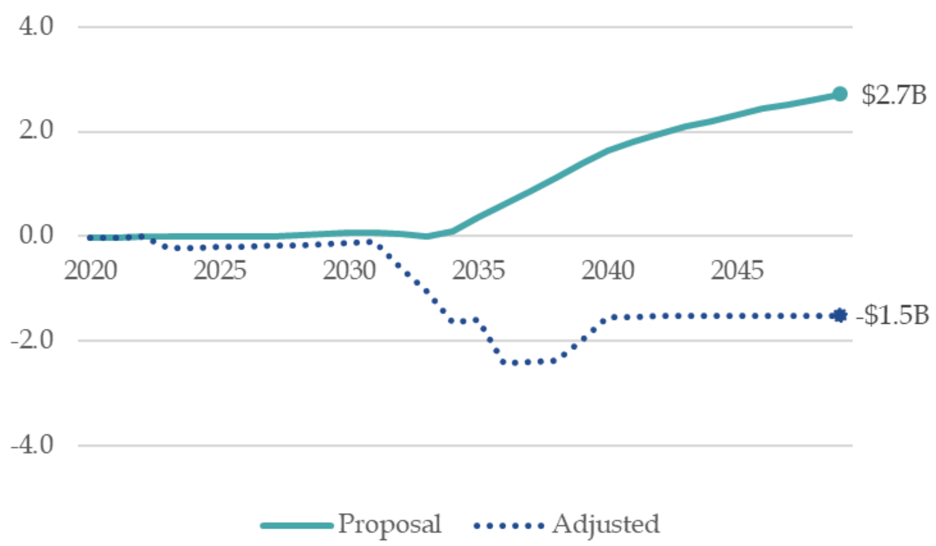
75 For example, changing the base value in the consumer price index (CPI) from 1,000 to 10,000 would not change the estimated quarterly rate of headline inflation.

76 This would be the equivalent of Statistics New Zealand changing the base value in the CPI from 1,000 to 10,000 and concluding that the quarterly rate of headline inflation was 10% instead of 1%.

This partially corrected cumulative estimate – now of a substantial *net cost* – follows a broadly similar trajectory through time.

Taken at face value, the CBA suggests that there would be no significant net benefit (in NPV terms) until ~2034.

Figure ES.12: Cumulative net benefits by time (NPV terms, $billion, $2018)[77]



The time profile of costs and benefits depicted in Figure ES.12 also calls into question why the Authority is insisting upon reforming the TPM now. The Authority has stated that it considers that changing the TPM is necessary and becoming increasingly urgent, since it is supposedly leading to inefficient investment and consumption outcomes.[78] Yet even taking its own CBA modelling at face value – with all its flaws – then:

The CBA is suggesting that there would be eleven years of virtually no net benefits and then the TPM could change substantially.

- the proposal would not deliver a significant net benefit in NPV terms for *twelve years*; yet
- as we mentioned earlier, the Authority expects that there would be a significant 'uncertainty event' – such as a major TPM review – after *eleven years*.[79]

In other words, even on its own terms, the CBA is suggesting that there would be eleven years of virtually no net benefits and then the TPM could change substantially. Consequently, even if all the errors in the CBA are ignored there is still no obvious reason to implement the Authority's proposed option – and certainly not as a matter of urgency.

Based on its own modelling assumptions, the proposal might deliver barely a dollar in net benefits before the methodology changes again. Moreover, even if those future benefits were not largely (if not entirely) illusory (which they appear to be in

77 Data used to generate the net benefit profile were sourced from the 'CS_results.csv', 'total_dg.csv', and 'transmission _costs.csv' files for the 'All_major_capex' scenario, the 'transmission_costs.csv' file from the 'Demand_major_capex' scenario, the 'Investment efficiencies.xlsx' and 'Summary of costs and benefits.xlsx' files and results from applying the Python code were used to estimate investment efficiency benefits.

78 Third Issues Paper, p.ii.

79 As we indicated earlier, this eleven-year assumption has no objective basis. It is simply taken 'as given' here for the sake of illustration.

this case), it is doubtful that *any* model could make predictions with any reasonable degree of certainty so far into the future.

Summary

The CBA modelling contains some obvious and, in many cases, very serious mistakes. Many of these errors are sufficient in their own right to cast considerable doubt over the efficacy of the estimated net benefit. In culmination, they serve to undermine completely the reliability of that result. In our opinion, the new CBA is just as flawed – if not more so – than its ignominious predecessor. For example, the $2.7b net benefit estimate:

- reflects the outcomes of modelling that does not depict the methodology that has actually been proposed; for example:
  - the grid use modelling (which produces 96% of the estimated net benefit) does not include the implicit forward-looking 'shadow' price signals that the Authority says would be supplied by the proposed BB charges; and
  - the 'top-down modelling' *does* include forward-looking price signals but, they are *wrong*, i.e., the model mistakenly assumes that consumers would face price signals that reflected a rudimentary measure of the LRMC of transmission, which is incorrect;[80]
- could be reproduced using virtually any methodology comprised solely of fixed charges, i.e., those fixed charges would not need to be based on estimated benefits – any number of alternatives could be used;
- includes $2.3b in wealth transfers that are neither benefits to New Zealand's economy nor improvements to the overall efficiency of the electricity industry – these are simply payments from one group of consumers (generators) to another (final consumers), i.e., this is not 'new wealth';[81]
- ignores the significant cost of additional investment in generation ($1.9b) and distribution networks (conservatively ~$27–$81m) that would be needed to support the noticeable increase in peak demand that the Authority has forecast to occur if its proposal was adopted;
- ignores the cost of additional carbon that would be likely to be produced if peak demand increased as forecast (since gas fired peaking plants are used to meet that incremental demand);
- was calculated using assumptions and investment decision rules that do not reflect reality, including that investors would not consider future returns when deciding whether to invest in grid-connected generation, which produces modelled outcomes that defy common sense;

80 This is exactly the same mistake that Oakley Greenwood made in its CBA. It assumed – wrongly – that shadow prices would reflect a measure of the regional LRMC of transmission. However, as we explained previously, BB charges *would not be cost-reflective*. The BB shadow price signals that individual customers would face would not be equal to LRMC.

81 An alternative to removing the wealth transfer would be to recognise the reduced revenue earned by generators as a cost in the CBA, of $3.9b in NPV terms.

- relies on modelled outcomes that do not appear to reflect reality either, including that an increase in peak demand would lead to a significant price reduction and that generation investment would continue even when wholesale revenues declined drastically;
- includes estimated benefits that are highly unreliable and based on arbitrary assumptions, such as those relating to greater scrutiny of Transpower's investment proposals ($77m) and increased certainty for investors ($26m);[82] and
- includes several calculation errors and statistically insignificant inputs that further undermine confidence in the analysis and conclusions.

Once these and other shortcomings are factored in, it is not possible to conclude that the Authority's proposal would deliver a net benefit to New Zealand's economy or improve the overall efficiency of the electricity industry.[83] For example, if the problems described in just the third and fourth bullets were addressed, then the estimated net benefit of the Authority's proposal would drop to **-$1.5b**, i.e., it would become a substantial **net cost**.[84]

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82 The Authority here has made the same mistakes that it made in its first CBA. In each case assumptions have been made about the value of key inputs based on nothing more than its subjective assessment of the *answer* that the analysis should be producing. In other words, benefits have been *assumed* rather than *estimated*.

83 The Authority interprets its statutory objective to mean that 'the TPM should promote overall efficiency of the electricity industry for the long-term benefit of electricity consumers'. *See:* Third Issues Paper, p.188.

84 This figure is obtained by taking the $2.7b net benefit estimate and subtracting $2.3b then $1.9b. To be clear, we are not suggesting that this represents a sound estimate of the likely net benefit – or cost in this case – from implementing the Authority's proposal. It is simply the revised result that one obtains when the two issues are addressed. Even with those corrections, the CBA remains unfit for its intended purpose on account of the many other shortcomings identified in this report. In other words, the CBA cannot be used to provide *any* reliable gauge of the overall quantitative impact of the Authority's proposal.

1. Introduction

This report has been prepared by Hayden Green of Axiom Economics (Axiom) and Eli Grace-Webb of farrierswier on behalf of Transpower. Its purpose is to evaluate the Electricity Authority's (Authority's) third transmission pricing review consultation paper ('Third Issues Paper').[85] Axiom's reports[86] in response to the second issues paper[87] and the supplementary paper that followed it[88] highlighted several problems with the proposals contained within them. Most notably, that:

- the combination of nodal prices and the so-called 'shadow prices' associated with the proposed the 'area of benefit' (AoB) charge (the precursor to the benefits-based (BB) charge) would not provide customers with an efficient *ex-ante* price signal of Transpower's future investment costs, and an *explicit ex-ante* price signal of some kind was needed to promote dynamic efficiency, such as a long run marginal cost (LRMC) charge;
- there was no reason to be confident that allocating the costs of investments after they had been sunk via an AoB charge would promote static efficiency or be more equitable overall, yet there was good reason to expect the proposal would result in more disputes and much higher administrative costs; and
- the cost-benefit analysis (CBA) undertaken by Oakley Greenwood[89] was not fit for its intended purpose, did not provide a robust indication of the likely impacts of the proposal and so could not reasonably be relied upon to support the proposed methodology.[90]

The proposal is largely unchanged from the Second Issues Paper.

Two years later, the Authority has produced a new CBA, but the broad scheme of its proposal is largely unchanged. The AoB charge has been rebranded the 'BB charge', but the key features are very similar. Transpower has asked us to review the material set out in the new consultation package and to consider whether it causes us to change any of the conclusions set out in previous Axiom reports. We do so in the remainder of this report, which is structured as follows:

85 Electricity Authority, *2019 issues paper, Transmission pricing review, Consultation paper*, 23 July 2019 (hereafter: 'Third Issues Paper').

86 Axiom Economics, *Economic Review of Second Transmission Pricing Methodology Issues Paper*, *A Report for Transpower*, July 2016 (hereafter: 'Axiom Report on Second Issues Paper'); and Axiom Economics, *Economic Review of Transmission Pricing Supplementary Consultation Paper, A Report for Transpower,* February 2017 (hereafter: 'Axiom Report on Supplementary Consultation Paper').

87 Electricity Authority, *Transmission Pricing Methodology: Issues and proposal, Second issues paper,* 17 May 2016 (hereafter: 'Second Issues Paper').

88 Electricity Authority, *Transmission Pricing Methodology: Issues and proposal, Second issues paper, Supplementary consultation,* 13 December 2016 (hereafter: 'Supplementary Consultation Paper').

89 Oakley Greenwood, *Cost Benefit Analysis of Transmission Pricing Options, prepared for: NZ Electricity Authority,* 11 May 2016 (hereafter: 'OGW CBA').

90 On 26 April 2017, the Authority conceded that Oakley Greenwood's CBA was irrevocably flawed and put a halt to its review.

- in **section two**, we set out some general observations on the manner in which the Authority has gone about arriving at its proposed option, including the various inconsistencies in analyses that have emerged over the last seven years;
- in **section three**, we consider whether there is anything in the Issues Paper that causes us to change our earlier conclusion about the efficiency of the forward-looking price signals that would be delivered by the proposed reform;
- **section four** sets out some of the potential adverse consequences that would be likely to flow from exposing load and generation customers to the inefficient forward-looking price signals associated with the proposed methodology;
- **section five** considers whether the proposal might represent a less distortionary, or fairer way of allocating the sunk costs of investments after they have been made and the potential impacts upon administrative costs;
- in **section six**, we run a ruler over the new CBA and consider whether it is fit for its intended purpose and supports the Authority's proposal;
- in **appendix A**, we provide a more detailed description of the CBA, including a more exhaustive account of the key input assumptions and its implementation;
- in **appendix B**, we step through in more detail the various problems with the CBA that, in culmination, undermine its credibility;
- in **appendix C**, we identify some specific problems with the proposed formulation of the price cap transition mechanism in the Draft Guidelines;
- in **appendix D**, we provide a list of all the earlier reports by Axiom's economists containing analysis and conclusions that have informed this report; and
- in **appendix E**, we provide a summary of the timetable for this TPM review, including key documents and milestones.

Note that, in the interests of parsimony, we have tried not to repeat the analysis set out in Axiom's previous reports. However, a degree of repetition has been unavoidable because, in many instances, the Authority has not addressed the points that were raised in those earlier reports, which has left us with no other option but to reiterate them. For the avoidance of doubt, the conclusions set out in those prior reports remain equally germane. Finally, we stress that the opinions expressed throughout this report are our own and do not necessarily reflect the views of Transpower.

2. General observations

In this section we set out some general observations about the manner in which the review has been conducted and recommendations have been made. There are now numerous inconsistencies across the nineteen consultation papers that have been released throughout the TPM review. Many of the things that the Authority is saying now cannot be reconciled with its past statements. Yet, in spite of all the contradictions, two things have remained constant over the last seven years:

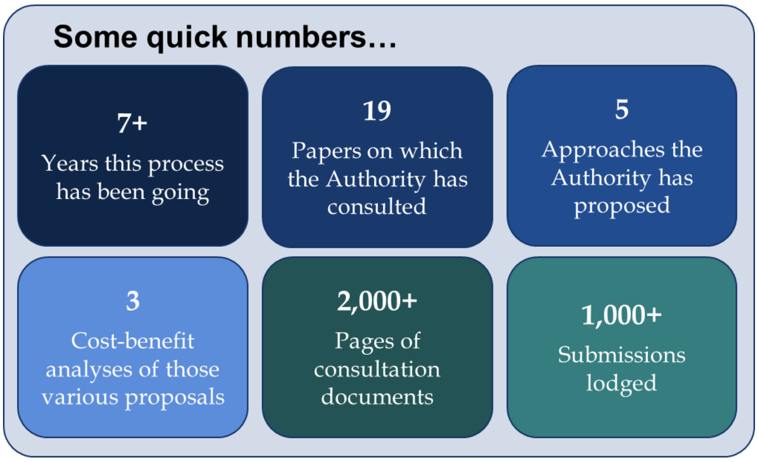
- every one of the proposals has been globally unprecedented; and
- every methodology has involved reallocating the sunk costs of past investments – primarily to North Island load customers.

Analyses have also tended to be overly narrow and recommendations have been predicated on assumptions about how the electricity market functions that do not reflect reality. These overarching issues have had wide-reaching impacts on the conclusions that have been reached throughout the review. In particular, they have caused the Authority to repetitively embrace radical untested approaches that would compromise efficiency – and to overlook more modest, orthodox reforms. This latest proposal is no exception.

2.1 Inconsistencies and contradictions

There are many inconsistencies across the nineteen consultation papers released during the TPM review.

The TPM consultation has been underway now for more than seven years. That timeframe is not remotely typical for a review of this nature. To put it in some in perspective, over the same period the Commission has reset electricity distribution businesses' default price-quality paths (DPPs) three times, gas distribution businesses' DPPs twice, Transpower's individual price-quality path (IPP) twice, finalised three customised price-quality paths (CPPs) and undertaken a complete review of its input methodologies (IMs). Throughout the TPM review so far, the Authority has released nineteen consultation documents spanning more than 2,000 pages – all to appraise nineteen short guidelines. It has put forward five different proposals – each of them without precedent – with three CBAs. Simply put, progress has been rocky.



There is perhaps no better example of this than the fact that, in September 2014 (see Appendix E), the Authority – at the urging of stakeholders – released a working paper in which it sought to articulate the problem that it had purportedly been trying to solve for the previous two and a half years. This 'Problem Definition' working paper was the tenth consultation document that had been released up to that point. Suffice it to say that arriving at a clear problem definition is normally the *first* step in any regulatory review – not the tenth.

In light of the way that the TPM review has unfolded it would be natural to expect there to have been some changes in the proposed approach as the Authority refined its thinking. Indeed, it is a regulator's prerogative – oftentimes its *obligation* – to change its mind in the face of well-reasoned submissions or other evidence. However, what we have seen recurrently is neither a gradual evolution nor a commendable responsiveness to compelling critiques. There have instead been numerous instances of the Authority abruptly reversing itself on key matters without adequate explanation. Often this has been in order to provide a new rationale for the same proposal when its prior reasoning has been exposed as unsound.

Axiom's report in response to the TPM Options Working Paper in August 2015 highlighted numerous inconsistencies and contradictions in the options that were being proposing at that juncture.[91] The report in response to the supplementary consultation paper identified many more.[92] The Third Issues Paper continues this trend of inconsistent analyses and conclusions. We shall encounter numerous examples as we canvas specific issues throughout this report, but we touch upon six of the more prominent case studies below.

2.1.1 Nodal prices: can they incentivise efficient investment?

Nodal prices play a vital role in efficiently rationing the demand for existing transmission grid assets. However, as previous Axiom reports have explained – and as we set out in section 3.1 – nodal prices have limitations. Most notably, by themselves, they do not provide sufficient signals to grid users of the costs that Transpower will incur in the long run when it replaces or upgrades its assets. In other words, nodal prices alone will not necessarily give rise to efficient investment in new assets. The Supplementary Consultation Paper released in December 2016 questioned that well-accepted economic proposition. It stated that:[93]

The Authority states that nodal prices can be relied upon to provide efficient short- and long-run price signals.

> *'… the Authority is of the view that submitters' concerns are overstated.* ***Provided nodal prices are allowed to operate to limit the use of the grid to its capacity until new investment is justified, nodal price signals will coordinate grid use among different parties so that the available capacity is used by those that benefit most from it****. As the second issues paper states, "the transport charge inherent in nodal prices provide price signals that encourage grid users to take into account the impact of their grid use on the timing of grid investments. In particular, the transport charge from the spot market should approach the marginal incremental cost of the corresponding amount of grid capacity in the*

91 We have not repeated those problems here, but they are set out at: Green H., *Economic Review of TPM Options Working Paper, A Report for Transpower*, August 2015, pp.37-41.

92 *See for example:* Axiom Report on Supplementary Consultation Paper, pp.11-13.

93 Supplementary Consultation Paper, p.5.

*years immediately before grid expansion is due to occur". **Thus grid users act as if they are coordinating their actions to avoid inefficient investment**.'* [our emphasis]

The 'Nodal prices and LRMC charging' paper that accompanies the Third Issues Paper reaches the same conclusion:[94]

*'In most of the situations where we have considered the case for an LRMC charge, the case for an LRMC charge does not stand up. Typically, **the best solution is to rely on nodal prices and instead focus on the responsiveness of demand and supply to nodal prices**.'* [our emphasis]

The suggestion that there is no need for an additional *ex-ante* price mechanism to prevent inefficient investment because nodal prices can do the job is incorrect as a matter of economics. This is not controversial – it is a widely-recognised consequence of the basic economics of transmission, as we highlight in section 3.1. The Authority's statements also cannot be reconciled with its previous position. Earlier in the consultation process its consistent – and quite *correct* – view had been that nodal prices *do not* provide efficient long-run signals for new investment. For example, the TPM Options Working Paper concluded that:[95]

This contention cannot be reconciled with the positions adopted in past papers.

*'Although nodal pricing provides efficient short-run price signals for use of the grid, **it does not provide efficient long-run signals.** Reliance on nodal pricing is insufficient to promote efficient transmission investment because **nodal pricing does not provide a sufficient price signal about the cost of the future transmission investment needed to supply changes in demand for transmission services**.'* [our emphasis]

In the same vein, the LRMC Working Paper concluded that:[96]

*'Some authors, such as Associate Professor James Bushnell of the University of California, Davis, who provided advice to Trustpower on the beneficiaries-pay working paper, suggest that nodal pricing is all that is required to promote efficient investment in relation to transmission. This appears to be based on a view that nodal pricing provides price signals that reflect both the SRMC and the LRMC for transmission. However, **nodal pricing is likely to result in price signals systematically below LRMC** … nodal prices are likely to under-signal LRMC so **LRMC charges could potentially promote more efficient investment**. However, while LRMC charges may be appropriate, nodal pricing will still provide some signal of marginal cost, albeit muted.'* [our emphasis]

There is a further conflict within the proposed methodology itself: namely, between the price signals supposedly provided by nodal pricing, and those said to be provided by the BB charge. As we explain in more detail in section 3.3, a key purpose of the BB charge is to elicit desirable behavioural change via *implicit* price signals (referred to in the Second Issues Paper as 'shadow prices'). The Authority has claimed that BB charges are:[97]

94 Electricity Authority, *Nodal Prices and LRMC charging*, p.5.

95 Electricity Authority, *Transmission Pricing Review, TPM options, Working paper*, 16 June 2015, p.53.

96 Electricity Authority, *Transmission Pricing Review, LRMC charges, Working paper*, 29 July 2014, p.29.

97 Third Issues Paper, p.217.

'… intended to promote efficient investment by grid users, ***by encouraging them to take account of the impact of their own use and investment decisions on the cost of new grid investment****.'* [our emphasis]

The basic premise of a BB charge is that, when deciding when and how to use the grid, customers would take into consideration the impacts of their actions on Transpower's future investment requirements. They would then make a further inference regarding the future BB charges that they would face under various scenarios and, if appropriate, 'rationally self-ration'. We explain in section 3.3 why this 'implicit pricing' theory is ill-conceived as a matter of economics, but there is an even more fundamental problem.

Namely, if nodal pricing can truly be relied upon to provide *all* the signals that grid users need to make efficient decisions, then why would the BB charge need to send any signal? Indeed, why would there need to be any *ex-ante* price signals in the TPM at all? If the Authority's new interpretation is accurate, then nodal pricing would be all that would be required to ensure that the right investments were made at the right times. It would be futile and counterproductive to try and elicit further responses from grid users via the TPM, since this could only compromise static and dynamic efficiency. Indeed, by that rationale, adding these (TPM-based) signals on top of existing (nodal price) signals would surely elicit inefficient *over*-reactions from grid users.

If nodal prices were sufficient to provide efficient price signals the TPM would become an exercise in pure ex-post cost allocation.

Instead, the only role for the TPM would be to allocate and recover the costs of investments in the least distortionary manner possible once they have been made. In other words, the sole goal of the TPM would be to *stop* grid users from changing their behaviour once efficient investments have been elicited via nodal pricing, i.e., the exclusive aim of the TPM would be to not impinge upon those perfectly efficient short- and long-run price signals. The best way to achieve that outcome would be via a broad-based tax – more akin to the proposed residual charge. At best, the BB charge would simply add needless complexity.[98]

However, the scenario described above is plainly not what is contemplated in either the Third Issues Paper or its predecessors. BB charges are clearly seen to have an important role to play signalling long-run costs. These myriad inconsistencies mean that we have not been able to discern the rationale for the proposition that 'nodal prices can do everything'. It remains a mystery.[99] In any event, whatever the motivation for the Authority's change of view, its revised position is not robust given the basic economics of transmission services, as we elaborate shortly.

98 However, as we explain in more detail subsequently, in reality, it would not just add complexity – it would also *compromise* dynamic and allocative efficiency.

99 We note also that the Authority has also been encouraging distribution businesses to use LRMC principles to introduce more cost-reflective tariffs – and several businesses have been doing so. This is also very difficult to reconcile with its statements in relation to LRMC charges and nodal prices in the Third Issues paper, since the basic economic principles are the same in the context of both distribution and transmission.

2.1.2 BB prices – predictable or not?

'Shadow pricing' has formed a key component of the last two proposals.

One of the centrepieces of the second issues paper was the benefits-based 'shadow pricing' theory. The contention was that it was not necessary to provide an explicit price to customers via the TPM *before* new investments were made to efficiently signal the extent of those incremental costs. Rather, it was said that customers would be able to predict their future benefits-based interconnection charges and then 'rationally self-ration' without ever having seen an explicit signal. This implicit signalling was thought to be *preferable* to more orthodox alternatives such as LRMC charges. As we noted earlier, this theory remains an important element of the latest proposal (although, as we shall see, largely absent from the CBA).[100]

Axiom's last two reports explained comprehensively why many customers would *not* be able to predict with any real accuracy the BB charges that they would face over the 40- to 50-year life of a transmission asset (we also pointed out various other flaws in the concept).[101] The Authority has acknowledged previously the implausibility of customers making the types of predictions that would be required for the shadow pricing theory to hold. For example, in its Distributed Generation Consultation Paper, it concluded that:[102]

The Authority has conceded elsewhere that customers could not predict and respond to shadow prices in the manner claimed.

> *'…there would be a significant impediment to distributors and owners of distributed generation agreeing to such contracts.* ***This is because they are unlikely to have the full information needed to determine what transmission investments might be required, and how the operation of distributed generation could defer the investment****. One consequence of this lack of information would be that distributors could not be confident that Transpower would actually defer the transmission investment(s) as a result of the operation of the distributed generation.'* [our emphasis]

In other words, the Authority has observed – rightly, in our view – that customers contemplating investing in distributed generation would be unable to predict the potential effects on transmission investment requirements. Yet, it is continuing to maintain that the same types of customers would respond to 'shadow pricing' signals that require precisely the type of foresight that it has admitted is beyond them. These two statements are irreconcilable. As we explain in more detail in section 3.3, we remain of the opinion that the 'shadow pricing' concept is problematic in numerous respects and that it would result in inefficiency.

2.1.3 Durability – strength or weakness?

The Authority claims that its proposal would promote durability and certainty.

One of the Authority's most noticeable discrepancies is in relation to one of the key purported benefits of the current proposal – and of the BB charge in particular. As we will explore in more detail later in this report, it is said that introducing a BB charge would promote 'durability' and improve certainty. Yet, it was the perceived *lack of durability* associated with 'locking-in' BB charges for prolonged periods that

100 Third Issues Paper, p.217.

101 *See for example:* Axiom Report on Second Issues Paper, pp.15-17.

102 Electricity Authority, *Review of distributed generation pricing principles, Consultation Paper*, 17 May 2016, Appendix E.2-E.3.

led to the so-called 'SPD approach' (that involved continually 'updating' beneficiaries) being preferred in the first issues paper seven years' ago:[103]

> *'The approach proposed by Professor Hogan of applying beneficiaries pay involves determining the charge that would apply to parties prior to an investment, with the charge fixed over time. Although this approach has some merits, the Authority considers that a key difficulty with such a charge is* ***it is calculated on the basis of anticipated benefits rather than actual benefits****. This creates a risk for efficient investment as parties will be reluctant to invest if they may continue to be subject to a charge even though they no longer benefit from the investment. This could adversely affect competition and does not take into account new entry.*
>
> *Although allocating FTRs to parties subject to the charge may mitigate the adverse impacts of such a fixed charge to some degree, this would not address situations such as a major beneficiary exiting the market. Although the charge could be recalculated if such an event occurred,* ***this would inevitably be subject to considerable dispute, threatening the durability of the approach****. By contrast, the SPD method does not suffer from these problems.'* [our emphasis; internal footnote removed]

The Authority has said previously that the proposed approach would ***not*** *be durable.*

It is curious that something that was perceived to be a core *weakness* of the 'lock-in' approach in 2012 is now apparently viewed as one of the BB charge's principal *strengths* (and a key 'benefit' captured in the CBA). No reasons are provided for this reversal in logic. As we elaborate in more detail at various points throughout this report, in our opinion, no satisfactory explanation exists. That is because, as the Authority has discovered throughout the course of the review, there is really no way to introduce a durable BB charging methodology. That is because:

There is really no way to introduce a durable BB charging methodology.

- if BB charges were revisited or recalibrated regularly to better-reflect the current pattern of benefits, then this would cause customers to change their behaviour in inefficient ways to reduce or avoid transmission charges (this is what led ultimately to the abandonment of the SPD approach); but
- if BB charges were locked-in and seldom – if ever – revisited (as the Authority now proposes) this would not be durable either for the reasons flagged by the Authority in 2012 – it would instead be a recipe for ongoing controversy as parties inevitably disputed those allocations and lobbied for them to be changed.

As we explain in more detail in section 5.2.2, under the proposed 'lock-in' approach, Transpower would need to make countless assumptions and judgement calls in relation to a multitude of highly uncertain factors when estimating private benefits. Those decisions would inevitably create winners and losers. Parties would fixate upon the assumptions underpinning their benefit calculations and charges and lobby for aspects to be changed. This would only get worse as market conditions changed over time and the assumptions that underpinned the initial calculations turned out to be inaccurate.

BB charges would be highly unpredictable.

Incidentally, much is also made in the Issues Paper of the supposed volatility and unpredictability of the RCPD charges. An example is offered of Electricity Ashburton's transmission charges increasing from $6.5m in 2018-19 to $16.7m in

[103] Electricity Authority, *Transmission Pricing Methodology: issues and proposal, Consultation Paper,* 10 October 2012, pp.100-104.

2019-20 due to the timing of peak periods.[104] However, as the Authority essentially conceded in the above extract,[105] the charges that customers would pay under the proposed BB charging methodology would be volatile and unpredictable as well. If anything, it would be even *more difficult* for customers to forecast their future imposts under the proposed approach.

2.1.4 Principal benefit – more efficient grid use or investment?

Hitherto, the key benefit of TPM reform has been said to be more efficient investment.

In a similar vein, there is a prominent inconsistency between the principal rationale underpinning this fifth TPM proposal and the four that preceded it. Hitherto, the Authority has extoled above all the importance of the TPM delivering more efficient long-term investment outcomes. In this latest paper that focus has shifted suddenly to the promotion of more efficient grid use. Indeed, the quantum of benefits supposedly on offer from more efficient grid use has skyrocketed relative to the last CBA; an incongruity that the Authority notes:[106]

> *'A key reason for this difference is that the 2016 CBA did not investigate consumer benefits arising from more efficient grid use. This was because they were* ***considered to be minor****. Instead, it focussed on* ***the benefits from more efficient investment****.'* [our emphasis]

The vast majority of the benefits from the latest proposal are said to flow from more efficient grid use.

This category of benefits that, until recently, was considered to be 'minor' is now said to be worth $2.6b – or *96%* of the net benefit estimate. That sum exceeds *by a factor of ten* the *total* net benefit estimate contained in the (admittedly profoundly flawed) OGW CBA. It is difficult to imagine there being a starker discrepancy between two analyses ostensibly designed to estimate the same thing. Perhaps unsurprisingly, our review of the CBA (contained in section 6 and Appendices A and B) has revealed that it is just as unreliable as its predecessor.

For example, almost all of the benefit attributed to more efficient grid use – around 88% – is nothing more than a bare transfer of wealth from generation customers to final retail customers. In other words, even taking the CBA as given, the Authority has not unearthed an enormous source of benefits that has been overlooked previously.[107] These transfers are not efficiency benefits in any meaningful sense.[108]

2.1.5 Costs – which ones need to be counted?

The manner in which the costs associated with the proposal have been estimated in the CBA exhibits equally conspicuous inconsistencies. As we explain in more detail

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104 Third Issues Paper, p.9.

105 See also section 2.1.2 and: Electricity Authority, *Review of distributed generation pricing principles, Consultation Paper*, 17 May 2016, Appendix E.2-E.3.

106 Third Issues Paper, p.21.

107 Moreover, as we explain in more detail in section 6, and Appendices A and B, there are numerous other fundamental errors in the methodology that has been used to derive this benefit estimate. Ultimately, there is no reasonable basis for drawing any conclusions at all from the analysis, because the methodology that has been employed is unsound.

108 The Authority itself has said that it 'does not take wealth transfers into account in making decisions.' *See:* Third Issues Paper, p.31.

The Authority counts $202m in avoided investments in batteries as a benefit in its CBA.

in section 6, one of the larger benefits said to flow from the proposal is $202m from 'more efficient investment in batteries'. This benefit would supposedly arise in the form of an *avoided cost*. Specifically, the contention is that, by removing the RCPD peak signal, the reform would:

- cause customers to increase their consumption – particular during peak periods (this is the source of the purported $2.6b 'grid use' benefit);[109] and
- discourage customers from spending $202m on batteries (as a proxy for all such technologies, including distributed generation and load control technologies).

However, despite counting these *avoided* capital costs as benefits, the model excludes many of the *additional* capital outlays that are said to stem from the proposal. For example, it is estimated (by the grid use model) that an extra $1.9b in generation (also in NPV terms) would be needed to meet the forecast increase in demand. This additional generation cost is nearly ten times higher than the $202m that has been included in the benefits assessment. This exclusion is justified in the following way:[110]

*The Authority does **not** count an extra $1.9b in generation investment as a cost in its CBA.*

> *'The CBA does not include any costs for generation investment brought forward. This is because the generation sector is assumed to be competitive, so any generation investment that occurs as a result of the proposal is assumed to be efficient investment.'*

This is not a satisfactory explanation. Not all investment in generation can be presumed to be efficient in an economic sense. Even if the wholesale market is workably competitive, generators still respond to the input price signals they are given. If they are inefficient, then generators might invest inefficiently – albeit in a competitive manner. Indeed, one of the main reasons the Authority has been trying to reform the TPM for the last seven years is because it thinks that it sends price signals that cause generators to make *inefficient* investment decisions.

The contention that the additional generation expenditure can be disregarded *in this instance* rests solely on a subjective belief that, because it would be happening in response to the Authority's preferred proposal, it *must be efficient*, and can therefore safely be omitted. By the same rationale, because the $202m in expenditure on batteries etc. would *not* be happening as a result of its proposal, it can also be presumed to be efficient and counted as a benefit. The bias in this approach should be self-evident.

The analysis is starting with the foundational assumption that the proposal would be efficient and then characterising everything that flows from it – whether that may be avoided costs or additional costs – as 'good'.[111] This is no way to perform a CBA. It involves making an assumption about the proposal – i.e., that it is efficient – that

109 As we explained above and in more detail in section 6, this estimate is fundamentally flawed.

110 Third Issues Paper, p.47.

111 Or, in the case of the additional distribution expenditure that would be likely to arise from the proposal, it concludes that it is 'beyond the scope' of the analysis.

the analysis is supposed to be testing. Put another way, the modelling has, in effect, commenced by 'first assuming the answer'.

2.1.6 Timing of review – is reform needed now or not?

The Authority considers that changing the TPM is necessary and becoming increasingly urgent, since it is supposedly leading to inefficient investment and consumption outcomes.[112] However, its CBA modelling does not support that conclusion. If taken at face value (i.e., ignoring all the errors that we describe throughout section 6 and Appendices A and B), then the CBA is indicating that:

The CBA model is suggesting that there would be eleven years of no net benefits and then the TPM could change substantially.

- the proposal would not deliver a significant net benefit in NPV terms for *twelve years*; yet
- the Authority expects that there would be a significant 'uncertainty event' – such as a major TPM review – after *eleven years* (see section 6.4.3).[113]

In other words, on its own terms, the CBA model is suggesting that there would be eleven years of no virtually net benefits and then the TPM could change substantially. Consequently, even if all the errors in the CBA are ignored there is still no obvious reason to implement the Authority's proposed option since, based on its own modelling assumptions, it might deliver barely a dollar in net benefits before the methodology changes again.

2.2 Enduring features

Amongst all the inconsistency and upheaval, two things in particular have remained unchanged throughout each and every one of the proposals that have been put forward over the last seven years. We describe and discuss these enduring features below.

2.2.1 Globally unprecedented methodologies

Every TPM reform proposal has been globally unprecedented.

To the best of our knowledge, each of the various TPM reform proposals has been globally unprecedented. To be clear, it is not unthinkable that a novel approach might be discovered that could work particularly well in New Zealand. But the fact is that the economic challenges associated with transmission pricing are very well understood. Accordingly, when a methodology is proposed that differs substantially from anything that exists elsewhere, it is perfectly understandable to pause and contemplate whether:

- a new and improved approach has been found that has escaped the attention of every other regulator; or
- if something important has been overlooked that has caused every other regulator to opt against implementing such an approach.

112 Third Issues Paper, p.ii.

113 As we explain subsequently, this eleven-year assumption has no objective basis. It is simply taken 'as given' here for the sake of illustration.

With the benefit of hindsight, several earlier proposals fell squarely into the latter category. The radical and untested 'SPD' and 'deeper connection' charges that were central features of previous methodologies were, on closer inspection, revealed to be deeply flawed. There were therefore very good reasons why they were not in use anywhere else. Despite this less-than-satisfactory experience with unorthodox pricing methodologies, yet another unique approach has been proposed in this latest paper. Two points in particular are worth noting in this respect.

First, we are not aware of any transmission pricing reforms that have been motivated by a desire to reallocate the sunk costs of past investments. As past Axiom reports[114] have explained, no dynamic efficiency gains can be achieved through such reallocations and the potential for static efficiency losses is obvious.[115] To that end, even the Authority concedes that, if it does ultimately elect to reallocate past sunk costs, then it:[116]

We know of no other reforms that have been driven by a desire to reallocate sunk investment costs.

> *'…would be **diverging from overseas precedent**. None of the three independent system operators (ISOs) or regional transmission operators (RTOs) we met in the United States applies a benefit-based approach to recover the costs of existing assets.'* [our emphasis]

Second, although there are some examples of jurisdictions in which the costs of *new* transmission investments are allocated to broadly defined customer groups based on estimates of their private benefits, there are no close approximations to what the Authority is proposing to adopt here. For example, in New Zealand, Transpower is the only transmission provider. We therefore do not have to overcome the types of coordination problems that can sometimes arise across multiple transmission network footprints in other countries like the USA.

When several transmission networks sit side-by-side (e.g., within and/or across, say, multiples states of the USA) scenarios may present where the most efficient way to meet demand growth in one location is to transmit more electricity from a cheap source of generation located further afield. In New Zealand, dealing with this is straightforward – Transpower identifies the best option, obtains regulatory approval and then invests. But, as Figure 2.1 illustrates, things may not be that simple when there is more than one operator involved.

In this example, Transmission operator B would be unwilling to upgrade its own network in order to facilitate the flow of electricity from network footprint A to C, since its customer would derive no benefits. Applying an overarching 'beneficiaries pay' charging framework via inter-state/region regulation can potentially break this deadlock by requiring the customers in locations A and C to pay for any investments that need to be made by Transmission operator B. But of course, this is not a problem that needs to be solved in New Zealand.

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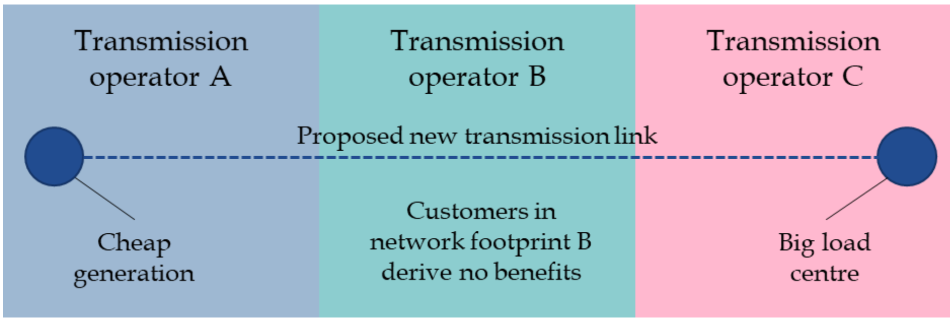
114 *See:* Green & Hird, *Transmission Pricing Methodology – Economic Critique*, February 2013, p.2.

115 It is doubtless for this reason that the Authority's net benefit estimate in its CBA goes up by $18m if the seven existing investments flagged for BB prices are excluded and subjected only to the non-distortionary residual charge. *See:* Third Issues Paper, p.49.

116 Third Issues Paper, p.116.

Figure 2.1: Potential coordination problems



Second, New Zealand is a tiny place. Our population is around 4.8m. By way of comparison, the combined population of the thirteen states that make up the PJM market in the USA is a tick over 100m – over twenty times larger.[117] None of the international examples of BB charging methodologies – such as the PJM approach – involve anything like the degree of 'granularity' seen in the current proposal. In the USA, it would be far more typical for the costs of a new investment to be split across, say, three states based on the estimated shares of benefits and for those costs to be recovered through postage-stamp pricing in each of those location.

There are no examples anywhere that are analogous to what the Authority is proposing.

In most cases, the 'sub-groups' across whom a share of the estimated benefits would be smeared would exceed Transpower's *total customer base*. For example, if 50% of the costs of an investment in the PJM market were allocated to, say, Illinois' customers, 25% to Pennsylvania's and 25% to Ohio's (to use a simple example) then, in each location, the costs would be being allocated over a population more than twice the size of New Zealand's. We do not know of any other place where benefits are calculated for and allocated to the small customer groups being proposed by the Authority. This aspect of the proposal consequently appears also to be without peer.

2.2.2 Reallocation of past sunk costs

If implemented, this fifth TPM proposal, like the four that preceded it, would require the sunk fixed costs of a sub-set of recent transmission investments to be reallocated. The reason that the Authority has continued to offer for proposing this redistribution is that there are currently customers – often in the South Island – who are paying for recent investments that are being used to deliver services largely to other customers – often in the North Island.[118] It considers this to be unfair and a threat to the durability of the regime.[119]

[117] The PJM market includes thirteen states: Delaware (907,135), Illinois (12.87m), Indiana (6.517m), Kentucky (4.369m), Maryland (5.828m), Michigan (9.876m), New Jersey (8.821m), North Carolina (9.656m), Ohio (11.54m), Pennsylvania (12.74m), Tennessee (6.403m), Virginia (8.907m) and West Virginia (1.855m).

[118] *See for example*: Third Issues Paper, pp.117-118.

[119] *Ibid.*

No dynamic efficiency gains can be achieved by reallocating sunk costs.

Axiom's past reports[120] have explained why there can be no dynamic efficiency gains from reallocating the sunk costs of past investments. [121] These reports have also demonstrated why the current allocation of transmission charges is unlikely to contain any cross-subsidies, which indicates that the TPM is 'cost-reflective'.[122] They have also stressed that *sub-optimal outcomes* can be created through reallocations, since large wealth transfers may cause market participants to act in ways that compromise both static and dynamic efficiency.[123] The government's Electricity Pricing Review panel even observed recently that:[124]

> *'**We are unaware of any other country undertaking retrospective reallocation of past grid investments**. Indeed, **some say retrospective reallocation is the principal obstacle to progress on a new TPM**. They say agreement could be reached more readily if a new TPM were confined to future investments – a feature of overseas transmission pricing.'* [our emphasis]

The compulsion to reallocate fixed costs via the TPM to engineer wealth transfers between and amongst load and generation customers becomes even less explicable when one considers the Authority's submission in response to the EPR panel's Options Paper. The EPR was considering whether to compel electricity distribution businesses to change the ways they allocated costs that were common between residential and business customers, in order to facilitate lower prices for the former. However, the Authority was strident in its view that reallocating costs in this manner *was not warranted* if the prices in question were subsidy-free:[125]

The Authority has opposed reallocations in other contexts.

> *'The Authority does not support this option. The EPR panel's technical paper in August 2018 found that cost allocation between residential and business consumers **appeared to be subsidy free**. Provided that distributors are not deliberately cross-subsidising consumers (and pricing methodology documents indicate distributors are not doing so), **distributors should be allowed to retain the flexibility to adapt their costing and pricing approaches to the needs of their individual networks**. We intend to monitor the methodologies and pricing adopted.'* [our emphasis]

In the context of *transmission* pricing, the Authority has therefore consistently supported reallocating costs to manufacture a particular outcome – despite the fact that there is no reason to think that the current tariffs contain cross-subsidies. Yet, when it comes to *distribution*, because the relative prices paid by residential and business customers appear to be subsidy-free, it has stated that there is no economic justification for any rebalancing.[126] In our opinion – and as we explain in more detail

120 *See:* Green & Hird, *Transmission Pricing Methodology – Economic Critique*, February 2013, p.2.

121 As we mentioned earlier, the Authority's net benefit estimate in its CBA goes up by $18m if the seven existing investments flagged for BB prices are excluded and subjected only to the non-distortionary residual charge. *See:* Third Issues Paper, p.49.

122 Green., H, *Economic Review of TPM Options Working Paper, A Report for Transpower,* August 2015, pp.19-23.

123 *Ibid*.

124 Electricity Price Review, *First Report for Discussion*, 30 August 2018, p.50.

125 Electricity Authority, *Electricity Price Review Options Paper submission*, 22 March 2019, pp.10-11.

126 Note that, just as with the matters described in section 2.1 above, these two positions are irreconcilable from an economic perspective.

in section 4 – the Authority's statements in relation to *distribution* pricing represent the correct approach.

2.3 Analytical approach

Throughout the seven-year period of its TPM review, the Authority's analyses – especially of alternatives to its preferred approaches – have tended to be unduly narrow. There have also been numerous instances where recommendations have been predicated on specific assumptions that do not reflect how the electricity market functions in practice. We elaborate below.

2.3.1 Narrow assessments

A noticeable feature of the various TPM proposals has been the way in which the respective merits of alternative pricing options have been evaluated. It has become a common practice to contrast an unduly narrow version of an alternative proposal with an idealised and unrealistic variant of the preferred option. For example, when comparisons have been made between an orthodox LRMC charge and a BB charge, the following approach has usually been taken:[127]

An unbalanced approach has been taken when analysing different pricing approaches.

- the presumption has typically been that any LRMC price would take a very particular form (e.g., that it would be very granular and volatile), when its design and application may be quite different in practice – and all the challenges associated with designing and implementing such a charge have tended to be emphasised acutely throughout the assessment; whereas
- the assumption has always been that BB charges would function highly effectively, i.e., that all customers would be able to predict their future charges, that those prices would be cost-reflective and that there would be no 'tragedies of the commons' when that does not provide a realistic depiction of how the methodology would operate, in practice.

This latest paper is no exception. To put it colloquially, the BB charge is treated like a 'favourite son' throughout the consultation documents, whereas LRMC pricing options seem to be viewed as the proverbial 'red-headed stepchild'. Traits that are shared by both pricing methodologies are seemingly viewed through a different lens, depending upon which charge is under consideration. A prominent example of this differential treatment arises when the Authority considers the uncertainties and inaccuracies that surrounds the derivation of both BB and LRMC prices.

Traits that are shared by different approaches can be viewed very differently

Numerous parties have highlighted the uncertainties inherent in BB charges. Put simply, it would be impossible for Transpower to estimate future benefits with any real degree of accuracy and, accordingly, for customers to predict their future charges with any confidence.[128] Moreover, as we mentioned earlier, even if BB charges are 'accurate' on 'day one' (which is unlikely), they would probably become

127 For a more comprehensive description of this phenomenon, *see:* Axiom Report on Supplementary Consultation Paper, pp.21-27.

128 *See for example:* Axiom Report on Second Issue Paper, pp.15-17.

less and less so over time as conditions (and benefits) inevitably changed in unexpected ways. The Authority acknowledges this uncertainty, but maintains that it does not represent a fundamental weakness:[129]

> *'In our view, this does not undermine the case for allocating charges according to net private benefit.* ***Perfection and total objectivity are not features of workably competitive markets and should not be expected*** *from the methods for the allocation of the benefit-based charge. Even with a* ***high degree of approximation****, we consider that the benefit-based charge would still provide much better incentives for grid users than is possible under the current guidelines.'* [our emphasis]

In other words, the extensive uncertainty – and unavoidable inaccuracy – that would surround the estimation of private benefits does not dissuade the Authority from subjecting the proposal to a CBA and, ultimately, recommending the approach. However, this accommodating attitude is not extended to LRMC pricing. The qualitative assessment of this alternative approach emphasises repeatedly the uncertainties, complexities and potential inaccuracies associated with the methodology. For example, it is stated that:[130]

Things that were not seen as key weaknesses of BB charging are enough to exclude LRMC pricing from further consideration.

> *'…it* ***remains questionable*** *whether the LRMC-based charge would improve efficiency in practice:* ***this would need to be tested through cost benefit analysis*** *…*
>
> *…In this case, the calculation of* ***the charge is quite complex****, which makes it* ***questionable*** *whether the LRMC-based charge would improve efficiency in practice …*
>
> *…This, together with the* ***difficulty of ensuring the estimate of the LRMC charge is reasonably accurate****, means that although* ***there is a potential case for an LRMC charge to encourage users to co-optimise investment, there is a very real risk of getting it wrong****. There is therefore a risk that the implementation of the charge in practice would be less efficient than not implementing it.* ***A careful analysis would therefore be desirable before it was introduced****.'* [our emphasis]

The Authority therefore conceded that there was a 'potential case for an LRMC charge' but considered that questions surrounding its complexity and potential inaccuracy meant that a more 'careful analysis' was desirable. However, that analysis was ultimately not undertaken. Rather, the 'uncertainties' alone were deemed sufficient to disqualify the methodology from further consideration. This is perplexing,[131] since the design and implementation challenges associated with the orthodox LRMC pricing approach are well-known[132] and clearly surmountable – as evidenced by its application in regulatory settings the world over.[133]

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129 Third Issues Paper, p.142.

130 Electricity Authority, *Nodal pricing and LRMC charging*, pp.2, 5 and 24.

131 This decision is difficult to comprehend because it contradicts the advice contained in the Authority's own LRMC paper which, as we set out above, recommended that the option be tested further – including through a CBA.

132 Axiom Report on Supplementary Consultation Paper, pp.5-8.

133 Transpower has also released a report by Sapere Research Group that stepped through in some detail the practical implementation issues that would need to be addressed before implementing an LRMC charge. *See:* Sapere Research Group, *Issues to consider in designing an LRMC pricing regime*, A report for Transpower, August 2017 (available: here).

Indeed, the Authority itself is *encouraging* electricity *distribution* businesses to implement LRMC-based tariffs. The 2019 distribution pricing principles state that prices are to 'signal the economic costs of service provision', including by (amongst other things) 'reflecting the impacts of network use on economic costs.'[134] They state also that: 'where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.' An obvious means of complying with these principles is to introduce an LRMC-based charge with a non-distortionary residual component – the very option the Authority has *rejected* in the transmission context.

The Authority is encouraging LRMC pricing in the distribution space.

That being the case, even on its own terms, it seems incongruous for the issues cited by the Authority in the Issues Paper to have been deemed sufficient in themselves to disqualify the approach from further deliberations – including within the CBA. Indeed, the Authority's *own staff* recommended that the option at least be included in the CBA.[135] And the decision becomes even harder to comprehend when the far greater challenges associated with designing and implementing the globally unprecedented BB charging approach are glossed over. In our opinion, these types of comparisons cannot provide useful insight into the respective merits of different pricing approaches.

Finally, as we explained in section 2.1.1, one of the principal rationales for rejecting LRMC-based options is the proposition that nodal prices can be relied upon to elicit efficient long-term investment decisions. This is said to obviate the need for any additional explicit LRMC-based price signal. But, as we observed earlier, the Authority appears not to have grasped that, if that contention were true (which it is not[136]), it would apply equally to the BB charge. Namely, if nodal pricing could provide *all* the signals that grid users need to make efficient decisions, then why would the BB charge be needed either?

If nodal prices really did render LRMC price signals redundant, then they would do the same for BB charges.

The Third Paper states clearly that a key purpose of the BB charge would be to provide implicit price signals to users to which they would respond (at least, that is the theory). Yet, if nodal prices are all that are needed to ensure efficient grid usage and the right investments are made at the right times then, by definition, those BB price signals *must be inefficient*. If nodal prices render LRMC price signals redundant, then they must do the same for BB prices. The Authority has neither recognised nor addressed this paradox.

2.3.2 Assumptions that do not reflect reality

The Authority's analyses and conclusions have also often hinged on specific assumptions about how the electricity market functions presently and how it will evolve in the future. In many cases, those assumptions have been inappropriate. They have either failed to represent accurately the realities of the power system or

134 Electricity Authority, *More efficient distribution network pricing – principles and practice Decision paper*, 4 June 2019, p.iii.

135 Electricity Authority, *Nodal pricing and LRMC charging*, p.2.

136 We explain why the proposition is incorrect in section 3.1.

The analyses and conclusions have hinged on certain assumptions about how the electricity market functions that do not hold.

the ways that parties operating within it make decisions. A clear example of this is an assumption that the Authority adopts in respect of nodal price signals and the extent to which parties would respond to them under its proposed approach (there are many others which we canvas in section B.2).

As we explain in more detail subsequently, a core proposition underpinning the proposal is that, in the future, retail customers will be exposed increasingly to 'granular' price signals to which they would respond in efficient ways, promoting allocative efficiency. Indeed, most of the net benefit estimate is derived from a modelled increase in consumer surplus that flows principally from a forecast reduction in nodal prices and a resulting increase in demand (particularly during peak periods).[137] However, as the Authority acknowledges:[138]

> *'Households and other small consumers are typically not exposed directly to nodal prices. Typically, these consumers enter into fixed-price variable-volume contracts for their electricity with retailers. Since these expose retailers to price risk, they are likely to cost consumers more on average than spot price contracts. The fact that consumers choose these contracts over (likely cheaper) spot price contracts and that retailers find this profitable means that these arrangements are likely to be efficient.'*

The Authority makes erroneous assumptions about how customers respond to nodal prices.

This creates something of a quandary. The proposal depends crucially on the assumption that the removal of the RCPD charge coupled with a forecast reduction in nodal prices would see retail customers ramping-up significantly their demand – especially in peak periods – in response. But the vast majority of retail customers *would not see* those nodal prices. Indeed, many enter into retail contracts precisely because they do not want to face those wholesale market risks. Therefore, what reason is there to think that customers would respond in the manner envisaged in the Third Issues Paper (and the CBA)? The Authority offers a novel solution to this problem. It states that:[139]

> *'…it is likely that retailers will endeavour to manage that risk by entering into a contract with a counterparty (such as a generator), so that the price risk is shifted to a party that is better placed to respond to nodal price variations. This means that,* ***even though the mass market consumer does not respond to nodal prices, the behaviour of other parties compensates for this so that the grid use responds as if they do****.'* [our emphasis]

In other words, the contention is that it would not be necessary for retail customers *themselves* to see and respond to nodal prices changes. In these circumstances, other entities – e.g., the customers' retailers – would respond in their stead, resulting in the same outcome that would have been observed if the customers had been exposed directly to the price signals themselves. This contention is incorrect. The only circumstances in which it would be accurate is if all a retailer was doing was

137 As we explain subsequently, most of this is not a true benefit at all, because the overwhelming majority of that estimated increase in consumer surplus is a bare wealth transfer from one group of transmission customers (generators) to retail customers.

138 Third Issues Paper, p.213.

139 Third Issues Paper, p.214.

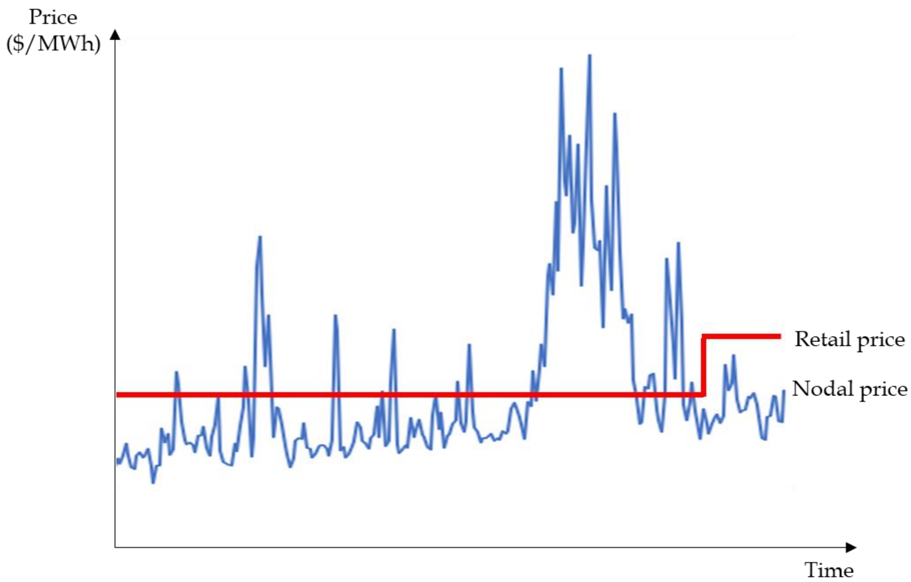
passing-on the spot price to customers – much like, say, a Flick Energy (which only serves a tiny share of New Zealand customers).[140]

In these cases, any increases or decreases in nodal prices *would* flow-through directly to retail customers in the manner envisaged. However, as the Authority itself concedes – most retail customers *do not want* those types of retail contracts. The ebbs and flows of spot market movements are therefore 'smeared' across time. Final customers never see – and do not want to see – the near-term temporal fluctuations. The fact that a retailer might itself respond by entering into a hedging arrangement with a generator is neither here nor there.

Indeed, if a retailer hedges against rising nodal prices, that does not mean that the price spikes that may have prompted it to do so would have been seen by its customers. Instead, those price rises would filter-through to retail prices over time in a much more aggregated fashion. Figure 2.2 illustrates. A retailer might respond to the rising nodal prices seen over this period by hedging with generators and, eventually, it might increase its retail contract prices via a 'step-change' to cover those rising wholesale costs.

Figure 2.2: Nodal prices vs. retail prices

Buying electricity from a retailer differs fundamentally to buying it from the spot market.



However, the overall effect would not be the same if retail customers themselves had been exposed directly to those nodal prices. If customers were paying the prices corresponding to the blue line in Figure 2.2 (nodal prices), the grid usage patterns would almost certainly be *completely different* than if they were paying the prices represented by the red line. In other words, there is no basis for the Authority's foundational assumption that grid usage outcomes would be the same, regardless of whether final retail customers are exposed directly to wholesale price signals.

[140] According to market data published by the Authority, Flick served only 0.93% of all ICPs as at the end of August 2019 (or just over 20,000 customers). Values sourced from the Authority's retail market share report (available at: www.emi.govt.nz, accessed on 17 September 2019).

Even the Authority's own CBA modelling suggests that consumer demand does not respond to changes in *retail* prices. The elasticity estimates derived from historical retail price changes are *statistically insignificant*. Faced with this difficulty, the Authority opts to estimate elasticities based on *wholesale* prices. In other words, despite being faced with evidence that consumers *do not* respond to retail price signals, it opts to use the correlation between wholesale prices and consumer demand as a proxy for responses to retail prices in its CBA.[141]

The Authority's modelling of generator entry decisions does not reflect reality.

The CBA's assumption regarding how generator entry decisions are made is also worth mentioning briefly. In the CBA, generation investment is modelled using a schedule of potential investments and selecting the 'lowest cost profitable' options.[142] However, the entry 'decision rule' that is adopted (equation 25 in the Technical Paper) assumes that generators would assess the financial viability of potential investments by looking only at *past and current returns* – and for a *single year*. That does not comport with reality.[143]

Like in any market, entry decisions are based on one principal factor: *projected future cashflows*. To that end, perhaps the most important factor that a firm would consider before investing in new generation is *future* wholesale prices. Even if spot prices were 'high' when a decision was being made, it does not follow that entry would result as a matter of course. If the business anticipated that its entry – and/or entry/expansion by others – would lead to a sharp reduction in nodal prices, then it may be disinclined to invest.

Generators decide to enter based on expected future cashflows – not past and current returns (as the CBA modelling assumes).

As we explain in more detail in section 6.3.1, this unrealistically narrow focus on the past and present gives rise to several counterintuitive outcomes that have compromised the CBA modelling. Most notably, it has caused the Authority to predict that an influx of new generation would take place in the mid-2030s that would lead to a precipitous reduction in peak wholesale prices, that would then avoid the need for additional investments in batteries. This is driving 96% of the net benefit estimate.[144] Yet, the approach is unsound.

A step-change in generation of this magnitude would be highly unlikely to transpire in reality, because the businesses would account for the sharp reductions in nodal prices that would be expected to follow. The economic viability of much of that

141 We use the term 'correlation' here quite deliberately. Without more, all that the regressions used to estimate the elasticities tell us is that there is some correlation between wholesale prices and demand. Other factors could be driving the correlation, such as changes in actual or projected demand. The uncertainty arises because annual demand quantities and prices are being used, when, in practice, demand response (to prices) occurs over much shorter time periods.

142 Electricity Authority, 23 July 2019, *CBA approach, methods and assumptions: TPM issues paper 2019, Technical paper*, p..54 (hereafter: Technical Paper').

143 Equation 25 – when reflected in the Python code used to model it – assumes that *all* capacity is dispatched across all time periods. This is highly unlikely to happen in reality given that generators are operating in a competitive market in which variable wind and water resources are also present.

144 The overwhelming majority of the benefit estimate itself is, in truth, simply a bare transfer of wealth from one set of customers (existing generators) to another (final retail customers), i.e., it is not a benefit at all. Moreover, the $1.9b additional resource cost of that new generation has been ignored by the Authority in its CBA – see section 2.1.5.

investment would be marginal at best, in *prospective* terms. The wave of new generation investment that is driving the net benefit estimate would therefore be unlikely to happen since, once again, the assumptions underlying it do not reflect how the electricity market actually functions.

2.4 Summary

There are several overarching problems with the manner in which the TPM review has been conducted and recommendations have been made. There are now numerous inconsistencies across the nineteen consultation papers that have been released over the last seven years. Many of the things that the Authority is saying now cannot be reconciled with statements it has made previously. We are not suggesting that a regulator cannot ever change its mind. Rather, what is strange here is the absence of any explanation for those changes – several of which have been dramatic and abrupt.

In our experience, when a regulator reverses its position it is customary for it to clearly articulate why – especially when it represents a critical part of the decision ultimately made, which has frequently been the case over the course of this review. Interestingly, amongst all this upheaval, there are two aspects of the proposals that have been unerringly consistent. Every methodology that has been proposed has been globally unprecedented and each has involved reallocating the sunk costs of past investments – primarily to North Island load customers.

The way in which the respective merits of alternative pricing options have been evaluated has also been conspicuous. It has become common practice to contrast an unduly narrow version of an alternative proposal with an idealised and unrealistic variant of the preferred option. The unbalanced way in which LRMC pricing has been compared with BB charging is a prime example. In our opinion, these types of analyses cannot provide useful insight into the respective merits of different transmission pricing approaches.

Analyses and conclusions have also often hinged on certain assumptions about how the electricity market functions that do not hold. A clear example of this from the Third Issues Paper is the assumption adopted in respect of nodal price signals and the extent to which parties will respond to them. The assumption is made that grid usage patterns would be the same whether retail customers are exposed directly to nodal prices or not, since the conduct of other parties – e.g., retailers – will compensate. That it not the case.

The influx of generation that is forecast to occur in the mid-2030s under the proposal is similarly divorced from reality. The model that predicts this step-change in investment ignores the most important determinant of entry decisions: *future* cashflows. It assumes instead that generators would assess the financial viability of potential investments by looking only at past and current returns. This is problematic, because:

- the model is suggesting that wholesale prices would drop sharply after this wave of new entry occurs – indeed, that is what is contributing most of the estimated net benefit in the CBA;[145] but
- it has not been recognised that, if spot prices would drop so fast and by so much following those new investments, then it is highly unlikely that all those generators would choose to enter in the first place.

These persistent issues have had a distinctly negative effect on the conclusions that have been has reached throughout the review. They have led to the embracement of radical, untested approaches lacking sound economic foundations at the expense of more orthodox, incremental reforms. This latest proposal is no exception. These problems have also affected adversely the CBA which, like its predecessor, cannot provide any meaningful insight into the merits of the proposed reform. We elaborate in the following sections.

145 As we explain in more detail in section 6.3.2, this benefit estimate is overstated enormously because almost all of it is a bare transfer of wealth from one set of customers (existing generators) to another (final retail customers), i.e., it is not a benefit at all. Furthermore, as we explained in section 2.1.5, the Authority has ignored the additional resource cost of that additional generation ($1.9b) in its CBA, despite including as a benefit the additional $202m that it claims will be spent on technologies such as batteries if the TPM is not reformed.

3. Forward-looking price signals

Axiom's previous report concluded that the proposed suite of TPM changes – most notably the replacement of the RCPD and HVDC charges with an AoB charge (now termed the BB charge) – would not provide efficient forward-looking price signals. Those reports explained why:

Previous Axiom reports concluded that the proposed methodology would not provide efficient forward-looking price signals.

- the explicit *ex-ante* price signals provided by nodal prices and losses would not provide sufficient signals to grid users of the costs that Transpower will incur in the long run when it replaces or upgrades its assets; and
- the implicit *ex-ante* 'shadow price' signal provided by the AoB charge would not provide a predictable, accurate signal of Transpower's long-run costs to which grid users could respond – even if they were inclined to do so.

We consequently concluded that an *explicit ex-ante* price signal was needed. We stated that such a charge might be a variant of the existing RCPD and HVDC charges, or a new LRMC charge. However, the Authority has ignored those findings and, as we noted earlier, proposed virtually the same methodology.

In particular, the Authority continues to maintain that nodal prices are sufficient to elicit efficient short- and long-run operational and investment decisions, obviating the need for an additional *ex-ante* price signal such as an LRMC-based charge. In this section, we explain why that is incorrect and the implications for the TPM. But we begin by recapping the obvious contradiction in the proposed approach.

3.1 Contradictions within the proposal

We explained in section 2.1.1 that the two most recent consultation documents have claimed that there is no need for an additional *ex-ante* price mechanism to be included in the TPM to elicit efficient investment. Instead, nodal prices have been said to be sufficient to efficiently ration the demand for existing transmission grid assets *and* incentivise efficient investments.[146] We explain shortly why that contention is incorrect as a matter of economics. But, for the sake of argument, let us suppose that it is not. As we noted earlier, if that proposition were true, three irreconcilable contradictions would arise.

The first incongruity is between what the Authority is saying now and what it has said in the past. As we set out in section 2.1.1 the Authority has stated clearly in previous consultation documents that nodal prices *do not* provide efficient long-run signals for new investment. There is no ambiguity. The position that is stated now is the demonstrable antithesis of what was set out in the TPM Options and LRMC Working Papers. For example, as we noted earlier, in the TPM Options Working Paper the Authority concluded that:[147]

146 *See for example:* Supplementary Consultation Paper, p.5; and Electricity Authority, *Transmission Pricing Review, LRMC charges, Working paper,* 29 July 2014, p.29.

147 Electricity Authority, *Transmission Pricing Review, TPM options, Working paper,* 16 June 2015, p.53.

The current position on nodal pricing cannot be reconciled with the positions adopted in past papers.

> *'Although nodal pricing provides efficient short-run price signals for use of the grid,* ***it does not provide efficient long-run signals.*** *Reliance on nodal pricing is insufficient to promote efficient transmission investment because* ***nodal pricing does not provide a sufficient price signal about the cost of the future transmission investment needed to supply changes in demand for transmission services****.'* [our emphasis]

The second inconsistency is between what the Authority is saying here, in the transmission context, and what it is saying in the distribution space. The Authority is now suggesting that there is no need for an LRMC-based price signal in the TPM. Yet, for years, it has been advocating for the introduction of more 'cost-based' distribution prices. For example, when the Authority assessed the pricing methodologies of distribution businesses in 2015, it concluded that one of the chief problems with the dominant charging methodology was that:[148]

> *'…there is no price signal to network users of the marginal cost of new capacity'*

And that:[149]

> *'Signalling the cost of new capacity involves pricing approaches that reflect the cost of supplying more capacity at times a network is congested (at which time demand on the network will be at its peak).'*

The Authority has been encouraging LRMC pricing options in the distribution space.

In other words, the Authority considered the absence of LRMC-based price signals to be highly problematic and urged distribution businesses to introduce them. To that end, the 2019 distribution pricing principles now state that prices are to 'signal the economic costs of service provision', including by (amongst other things) 'reflecting the impacts of network use on economic costs.'[150] They state also that: 'where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.'

An obvious means of complying with these principles is to introduce an LRMC-based charge with a non-distortionary residual component – the very option the Authority has *rejected* in the transmission context. [151] It is not clear to us why LRMC charging would be considered meritorious – if not *necessary* – in the context of distribution pricing, but not so in the case of transmission pricing. From our perspective, in each instance the basic economic principles are the same.

The third contradiction is created within the proposal itself. The proposition that 'nodal prices can do everything' has been used primarily to refute submissions favouring the retention of an explicit forward-looking price signal in the TPM, e.g., a variant of the RCPD charge or an LRMC-based price. The contention has been that those additional price signals would be unnecessary and inefficient, because nodal

148 Electricity Authority, *Implications of evolving technologies for pricing of distribution services, Consultation Paper*, 3 November 2015, p.65.

149 *Ibid.*

150 Electricity Authority, *More efficient distribution network pricing – principles and practice Decision paper*, 4 June 2019, p.iii.

151 For instance, in response to the Authority's pricing principles, Orion is using LRMC to inform its pricing structures, particular peak prices. *See:* Orion, *Methodology for deriving delivery prices*, *For prices applying from 1 April 2019*, 22 February 2019 p.2.

prices can be relied upon to provide *all* the signals that grid users need to make efficient decisions. However, the Authority appears not to have recognised the implications of this for its own proposal.

If it were true that nodal pricing could be relied upon to elicit efficient short-run usage and long-run investment decision (which, as we explain below, it cannot), that would undermine the case for *any* additional forward-looking signal. This has obvious implications for the proposed BB charge. A key purpose of the BB charge is to elicit desirable behavioural change via *implicit* price signals. The idea is that customers would respond to those price signals by 'rationally self-rationing' when appropriate. Specifically, the Authority has claimed that:[152]

> *'…transmission customers that are required to pay a benefit-based charge for a future grid investment will have an incentive to take transmission costs into account in making decisions about their own investments and use of the grid.'*

If nodal prices were sufficient to provide efficient price signals the TPM would become an exercise in pure ex-post cost allocation.

Of course, if nodal prices could do what the Authority is saying they can, then it would be futile to try and elicit these types of responses from grid users via BB charges. Those implicit prices could serve only to compromise static and dynamic efficiency, since nodal prices would already be providing all the signals that customers need to see. Anything else would be too much, by definition. The only role for the TPM would be to allocate and recover the costs of investments in the least distortionary manner possible once they have been made.

In other words, if the Authority's view of the world was accurate (which it is not), then the sole goal of the TPM would be to *stop* grid users from changing their behaviour once efficient investments had been elicited via nodal pricing. The idea would be to design a TPM that did not impinge upon the perfectly efficient short- and long-run price signals supplied by the wholesale market. The exercise would be one of pure *ex-post* cost allocation, ideally involving no *ex-ante* price signalling at all. There would certainly be no place for a BB charge.

The best way to achieve efficiency in such a world would be via a TPM where the costs of interconnection and HVDC assets were recovered via a broad-based tax – more akin to the proposed residual charge. At best, the BB charge would simply add needless complexity.[153] However, as we foreshadowed earlier, the world view depicted in the Third Issues Paper and its predecessor does *not* reflect reality. Rather, the Authority had it right when it concluded in its TPM Options and LRMC working papers that nodal prices *do not* provide efficient long-run signals. There is consequently an important role for the TPM to play in 'plugging the gap'.

[152] Third Issues Paper, p.115.

[153] However, as we explain in more detail subsequently, in reality, it would not just add complexity – it would also compromise dynamic and allocative efficiency.

3.2 Limitations of nodal prices

Nodal prices alone may not be sufficient to elicit efficient long-run outcomes.

As previous Axiom reports have explained[154] (and the Authority has also highlighted previously[155]), the problem with relying exclusively on nodal prices to incentivise both efficient short-term usage and long-term investment decisions is that they would *systematically under-signal* the LRMC of future capacity expansions. That would not happen in a competitive market. Rather, when competition is workable, new investments (entry and expansion) will occur when the cost of investing to meet additional demand (the LRMC) is less than or equal to the cost of rationing demand to the level of existing capacity (the SRMC).

The Third Issues Paper provides a worked example of how pricing and investment decisions are typically made in competitive markets involving a hotel.[156] Axiom's previous report included a very similar – albeit more comprehensive – illustration.[157] This provides a useful framework for highlighting the important differences in the relationship between short- and long-run marginal costs in a competitive market and in the very different context of electricity transmission. To that end, suppose for the sake of illustration that:

- there is currently only one hotel in a small town; but
- the market is competitive, i.e., there are no barriers stopping other hoteliers from entering or the current hotel from expanding its premises.

Nodal prices do not signal adequately long-run investment costs, leaving a 'missing price signal'

In the short run, the number of hotel rooms in town is fixed. This means that the most efficient way to deal with excess demand during peak periods (e.g., on New Year's Eve) would be to increase the prices for the existing rooms.[158] This is because:

- it would not be possible to construct a new hotel or expand the existing building in the near-term, e.g., to find a site, obtain planning approvals, arrange financing, undertake construction, and so on; and
- those investment decisions would not be based solely on one period of high prices in any event – rather, it is the expected returns over a longer time horizon that would be relevant for entry/expansion decisions.

However, if demand kept growing to the point where the hotel was constantly increasing its prices to curtail demand then, in the long run, it may be more efficient to build more rooms, i.e., to expand supply. In unregulated competitive markets, this 'tipping point' would occur when the expected cost of *curtailing* demand (as represented by the SRMC) increased beyond the cost of expanding capacity to *meet*

154 *See:* Axiom Report on Second Issues Paper, pp.4-8 and Appendix A; and Axiom Report on Supplementary Consultation Paper, pp.13-15.

155 *See for example:* Supplementary Consultation Paper, p.5; and Electricity Authority, *Transmission Pricing Review, LRMC charges, Working paper,* 29 July 2014, p.29.

156 Third Issues Paper, p.192.

157 Axiom Report on Supplementary Consultation Paper, pp.13-15.

158 Similarly, if the hotel experienced a temporary period of low prices due to reduced demand it is not going to respond in the near term by reducing the number of rooms or by exiting the market.

it (as represented by the LRMC) – either via new firms entering, or existing suppliers expanding. At that point, efficient new investment would take place.

However, as Axiom's previous reports have explained at length,[159] this relationship between SRMC and LRMC that is observed in unregulated competitive markets *does not apply* in the context of electricity transmission services. To see why, suppose that our hotel is no longer free to set whatever prices it likes for its rooms or to invest in whatever manner it pleases. Suppose instead that it is subject to several important practical constraints. For example, imagine that:

Once practical constraints are applied, the investment outcomes change.

- there is a maximum price that the hotel may set per room, irrespective of the level of demand, e.g., a cap of $1,000 per room per night, even though some customers might be prepared to pay more;
- most of its guests book their rooms through an intermediary that 'smooths out' the fluctuations in the prices charged by the hotel and offers customers an 'averaged' price that largely disguises any 'peaks' and 'troughs'; and
- the hotel has an obligation to ensure that there is always a room available to anyone who wants one, i.e., an explicit 'lodging guarantee' to ensure that supply can always meet demand.

Would one still expect to see the same new investments happening at the same times and in the same ways? Almost certainly not. The most likely outcome is that the hotel and/or new entrants would invest sooner and, potentially, build bigger. Why? Because the practical constraints listed above would serve to prevent hoteliers from allowing room prices to ever reach the levels that would signal to customers the LRMC of expanding capacity. It simply could not wait that long.

The situation is the *exactly the same* in the context of electricity transmission services. As Axiom's previous reports highlighted – and the Authority itself acknowledged in its LRMC Working Paper[160] and elsewhere – there are sound, practical reasons why new transmission investments will often be made before nodal prices ever reach the levels that would signal to grid customers the LRMC of those grid expansions. These include the following:[161]

- if nodal prices are capped below the true value to customers of 'lost load', spot price differences will be highly unlikely to reflect the LRMC of the network (this is the 'transmission equivalent' of the $1,000/night cap on hotel room prices);
- most 'final' electricity customers are insulated from the immediate impacts of nodal prices through the 'risk aggregation' function provided by their retailers (this is the 'transmission equivalent' of the intermediary 'smoothing' prices); and

159 *See:* Axiom Report on Second Issues Paper, pp.4-8 and Appendix A; and Axiom Report on Supplementary Consultation Paper, pp.13-15.

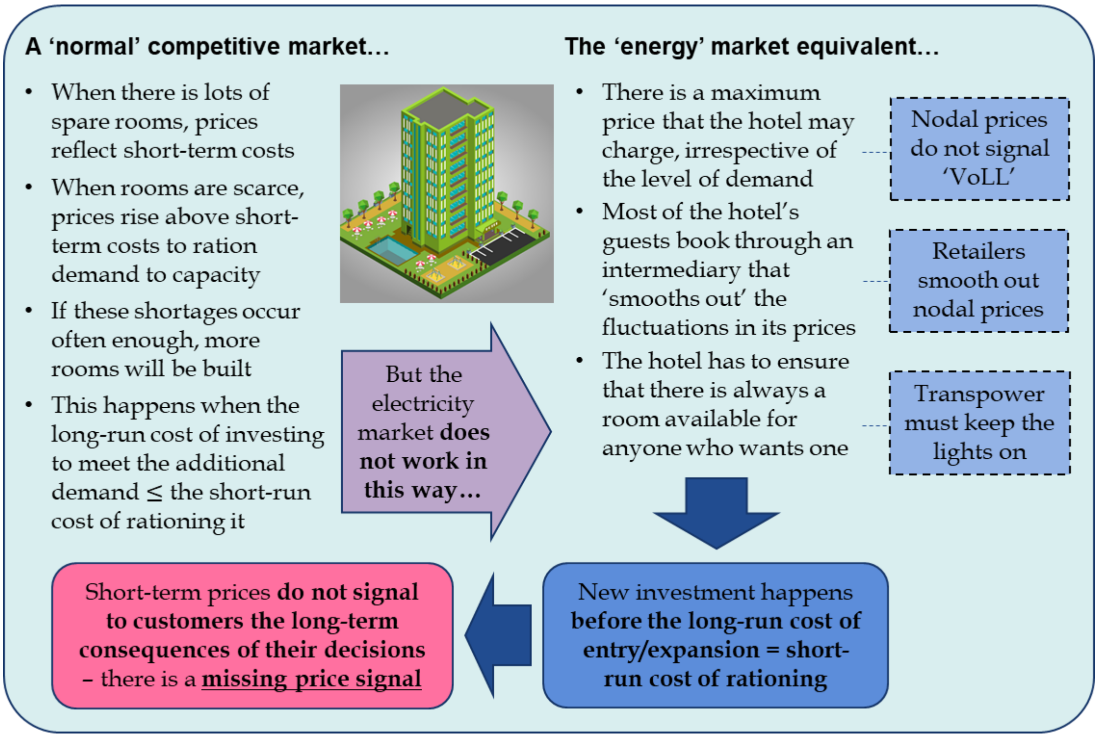
160 Electricity Authority, *Transmission Pricing Review, LRMC charges, Working paper,* 29 July 2014, p.30.

161 Note also that market power problems may lead to overbuilding transmission to promote competition generally in power markets and there are valid national security reasons to overbuild transmission rather than risk the comparatively more severe consequences of underinvestment.

- transmission planners build sooner rather than later and adopt reliability standards (e.g., the N-1 standard for the core grid) that are independent of economic costs (this is the 'transmission equivalent' of the obligation to provide a hotel room to 'all-comers').

Transpower is therefore more analogous to the 'constrained' hotel described above. It cannot wait for nodal prices to increase to the level of LRMC before investing, since that might risk 'the lights going out' or otherwise breaching its reliability standards. Without some other *ex-ante* price signal, it might therefore need to invest in new grid capacity *before* nodal prices hit LRMC (i.e., new transmission grid assets could be built when SRMC < LRMC). Figure 3.1 illustrates.

Figure 3.1: A hotel analogy – the missing price signal



Absent an additional price signal, efficient investment outcomes cannot be assured.

This has profound implications for the design of the TPM. These practical factors stemming from the basic economics of transmission mean that, in the absence of some other additional price signal, efficient investment outcomes cannot be assured. Specifically, today's grid users may not factor the potential consequences of their actions for Transpower's long-run investment costs into their consumption and investment decisions. For example:

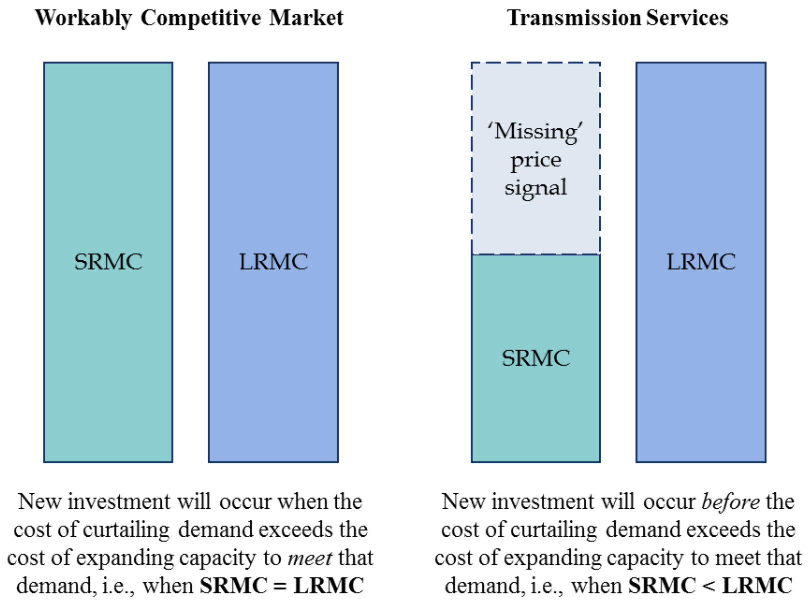
- load customers may decide not to curtail their demand in peak periods in response to higher nodal prices (e.g., a 'higher' SRMC), because those signals *might not be strong enough*;
- that incremental demand may then 'bring forward' the need to undertake a new investment, which might not have happened had those additional costs been signalled in advance in some way; and

- because of the factors described above, new investment may take place before nodal prices increase to a level that reflects the LRMC of that outlay, in which case customers would *never see* the 'true costs' of their actions.

The question is: what is the best way to provide the missing price signal?

It follows that, for customers to be made aware of the consequences of their actions on Transpower's *future* costs *before* they are incurred, something beyond the signal provided by nodal prices is needed. Something is required that signals the 'gap' that exists between the SMRC and LRMC. Figure 3.2 – which has appeared in several prior Axiom reports – summarises this well-accepted phenomenon. The question therefore becomes: what is the best way for Transpower to provide this 'missing signal', thereby potentially giving rise to more efficient investment outcomes?

Figure 3.2: Gap between SRMC and LRMC



There are various ways in which the missing price signal could be provided.

There are various different ways in which additional forward-looking price signals might be provided to customers with a view to producing more efficient long-term investment outcomes. The existing RCPD and HVDC charges already do so – albeit with material limitations. Various alternatives also exist – including the BB charge proposed by the Authority. We begin by considering some of the potential options that the Authority has *not* recommended, before examining the merits of its preferred approach.

3.3 Alternatives that the Authority did not recommend

There are many different ways to address the 'missing price signal' problem described in the previous section. Three potential options are considered in the Third Issues Paper and rejected. However, before we look at those alternatives, we explore briefly the simplest option of all – namely, supplying *no* additional forward-looking signal, i.e., leaving the gap 'unplugged'.

3.3.1 Have no additional signal

One potential reform option would be to replace the RCPD and HVDC charges with a single, non-distortionary residual charge on load. As we noted earlier, if the Authority's claim that nodal pricing can 'do everything' were accurate (which it is not), then this is an option that might logically be adopted. As we explained previously, the idea would be for the TPM to provide *no* price signals whatsoever. Its principal purpose would be to try and *disincentivise* customers from changing their behaviour once investments had been made, i.e., it would be an exercise in non-distortionary sunk cost allocation.

Removing the RCPD signal would stop any inefficient load shedding.

In the near-term, this approach might even appear to work quite well. For example, throughout the grid, SRMC and LRMC may both be quite low at present and not materially different from one another – especially if the recent investments have created widespread spare capacity. It is therefore possible that there are relatively few benefits to be derived currently from seeking to supply the 'missing price signal'. The optimal incremental signal might therefore be quite low, i.e., the 'gap' in Figure 3.2 might be quite small, on average, at the moment (perhaps even zero in some instances).

If it is indeed the case that the peak price signal being supplied by the RCPD charge is too strong, then switching to a broad-based fixed charge might consequently deliver some allocative efficiency benefits. Specifically, if the RCPD charge is *over-signalling* the 'gap' between SRMC and LRMC then customers may be inefficiently curtailing their demand when it would be more beneficial for them to be using the existing surplus capacity. Switching to a broad-based residual charge with no 'peaking' element would address that issue – at least for the time being.

Problems would arise when constraints started to re-emerge, since nodal prices would not signal LRMC.

But, of course, those benefits would be short-lived. In time, demand would grow, and constraints would start to re-emerge. Without some form of additional price signal, Transpower would (perfectly understandably) invest in new capacity before those constraints signalled to customers through nodal prices the true LRMC of expanding the grid (see section 3.2). Any near-term benefits obtained from replacing the RCPD and HVDC charges with a broad-based tax would then be swamped by the dynamic inefficiencies associated with not adequately signalling to customers long-term costs.

It is presumably for those reasons that nobody has proposed to reform the TPM in this manner – and we are certainly not recommending it. Nonetheless, it is a scenario that is worth bearing in mind because, as we explain in more detail subsequently, the overwhelming majority (96%) of the benefits that the Authority has ascribed to its proposed approach would also be achieved under this much simpler – albeit deeply flawed – alternative. The fact that a methodology that is so obviously flawed would, based on the Authority's own logic, deliver billions of dollars of benefits relative to the status quo is, in our view, a good reason to be sceptical of that analysis.

3.3.2 Retain the RCPD and HVDC charges

The RCPD and HVDC charges that are features of the status quo each provide long-term price signals of a kind. The RCPD charge provides a signal to load customers to cut demand during peaks. A customer facing the RCPD charge will consider whether there is anything that she can do to reduce demand – such as investment in distributed generation – that will cost her less than what she is likely to pay if she does not respond. If there is, then:

- the customer will rationally seek to avoid the charge (e.g., by investing in distributed generation or demand-side management), reasonably confident that it will be financially beneficial to do so; and
- if that type of response is sufficiently widespread amongst market participants, it may push back the time at which Transpower has to incur those future costs, resulting in broader market benefits.

The 'strength' of the signal to curtail demand can also be adjusted by changing the number of periods over which the contributions to RCPD is measured, for example:

The RCPD charge provides an explicit forward-looking price signal – but it has limitations.

- when RCPD is approaching the available grid capacity (e.g., just before the investment is made and LRMC is 'high'), a smaller number of periods might be used (e.g., 10 or 12) to encourage load shedding; but
- when RCPD is significantly less than available capacity (e.g., straight after an investment is made and SRMC and LRMC are 'low'), a larger number of periods could be used (e.g., 1,000 or 17,520) to dampen the signal.[162]

However, the RCPD charge does have some limitations. First, it does not necessarily provide customers with a signal that reflects Transpower's *forward-looking* LRMC. Rather, it signals to customers that, if they do not curtail demand, they risk paying a larger share of the sunk costs of *existing* interconnection assets. To be sure, there may be a correlation between the RCPD signal and LRMC, but they will not be the same – the signal could be too strong or too weak. As the Authority explained at its regional TPM workshops, there is good reason to think that it may currently be the *former*.

Second, because the charge must recover a fixed amount of revenue – i.e., to fund Transpower's interconnection assets – customers' individual charges cannot be worked out until *after* they have consumed the relevant interconnection service. In other words, although the RCPD charge provides customers with incentives to curtail demand,[163] they do not know exactly what prices will ultimately be paid. In most cases, they may have a reasonably good idea but there are exceptions (e.g., Electricity Ashburton's recent experience[164]).

162 Following its first 'operational review' Transpower increased the number of periods over which RCPD is measured in both the UNI and USI regions from 12 to 100 for precisely this reason.

163 Under the RCPD charge, it may be a 'dominant' strategy for a customer to curtail demand since, if it does not, and others do, it will pay higher interconnection charge.

164 Electricity Ashburton's transmission charges increasing from $6.5m in 2018-19 to $16.7m in 2019-20 due to the timing of peak periods. *See:* Third Issues Paper, p.9.

Third, the price signal is also provided at a relatively aggregated level, i.e., for four regional areas. That is not necessarily a bad thing, since it reduces administrative costs, *vis-à-vis* having a larger number of prices. But it does nevertheless limit Transpower's ability to signal *infra-regional* constraints. Moreover, the only 'lever' at Transpower's disposal to adjust the strength of the charge is the number of periods over which it is measured. If it does not pull that lever in time, or with the right amount of force, inefficiency can arise.[165]

Fourth, the way in which the charge is formulated means that it is not possible to 'turn it off completely'. For example, if contributions to RCPD are measured over 17,520 periods (i.e., every pricing period), the price effectively becomes a $/MWh usage 'tax' on load customers, which may compromise allocative efficiency. Conversely, a LRMC price could, in certain circumstances (e.g., immediately following large investments) be set to 'zero', to incentivise the greatest possible usage of that new capacity.

The HVDC charge provides an explicit price signal to South Island generators – but it also has limitations.

The HVDC charge also provides a forward-looking price signal. It lets generators know that the impact on Transpower's forward-looking transmission costs will be greater if a new investment is made in the South Island, rather than the North Island, all other things being equal. In other words, it provides an 'inter-island' locational pricing signal for prospective generation investments. Curiously, the Third Issues Paper simply asserts that the HVDC charge is *inefficient* because it 'acts as a disincentive to invest in South Island generation.'[166] That does not follow as a matter of economics. The matter is more nuanced.

The work undertaken by Green *et al* (2009) for the CEO Forum, and the subsequent modelling work by Transpower, demonstrated that it is costlier, from a transmission network perspective, for generators to locate in the South Island than the North Island. There is consequently nothing wrong, *per se*, with the TPM signalling as much. The question is whether the HVDC charge, as currently formulated is sending the *right* signal. Specifically, the existing HVDC charge – which, again, reflects *past* investment costs – does not necessarily provide a signal of *forward-looking* LRMC. It therefore may not be pitched at the right level.

It is possible that the existing price signal is currently too strong, or too weak. To ascertain whether the HVDC charge could result in inefficient generation location decisions it would consequently first be necessary to compare that price to the LRMC of transporting electricity from the South to the North Island. That work has not been done.[167] Until it is, there is no empirical basis to conclude that removing the

165 Indeed, as we explain throughout the remainder of this report, the Issues Paper makes a strong case that the current RCPD signal is too strong, i.e., that it is measured over *too few* periods.

166 Third Issues Paper, p.11.

167 At the Whangarei TPM workshop the Authority stated that it *had* been established that the HVDC charge was inefficient because: 1) South Island generators were not the only beneficiaries of the link; and 2) North Island generators did not pay HVDC charges. However, neither of those factors is germane to the question of whether the HVDC charge currently constitutes an inefficient tax on South Island generators. The only thing that matters is whether the HVDC charge is signalling to

existing price signal would improve the efficiency of generation investment outcomes.[168] It could instead compromise dynamic efficiency.

To summarise, both the RCPD and HVDC charges provide additional, explicit forward-looking price signals to customers that complement nodal prices to some extent. However, they both have their limitations – many of which have been highlighted throughout the review. As previous Axiom reports have explained, there may therefore be the potential to modify the TPM in beneficial ways that address some of these shortcomings. However, as we elaborate below, the Authority is yet to propose an economically robust means of doing so.

3.3.3 Wait longer to invest or augment nodal prices

In the LRMC paper that accompanies the Third Issues paper, two novel alternatives are offered to the problem described in section 3.2 – neither of which are ultimately recommended. The first suggestion is to insist simply that Transpower waits longer before it invests, i.e., to allow nodal prices to rise to the point at which they are signalling the LRMC of expanding capacity before undertaking new investments. In other words, the suggestion is that Transpower could just wait until *there is no gap* between SRMC and LRMC before investing. The Authority states that:[169]

> *'…it is suggested that users never see the full costs of their actions because investment is usually triggered 'early', before nodal prices have risen to levels commensurate with signaling [sic] that additional investment would be beneficial. If this is so, it is because there is some mechanism, other than nodal prices, that is triggering the investment. The appropriate policy solution is not to increase the nodal price with an LRMC charge, but to address the problem that is causing the early investment.'*

Waiting until a theoretical optimal 'trigger point' to invest is unrealistic.

The assumption here seems to be that, if no additional signal was provided, and Transpower invested before nodal prices had increased to heights reflective of LRMC, then it would somehow be acting inefficiently. In our opinion, this suggestion is impractical in that it disregards the way in which transmission investment decisions are made and the highly asymmetric consequences of building 'too big and/or too soon' versus 'too small and/or too late'.

generators the higher long-run cost of investing in the South Island. That is an entirely *cost-based* analysis – it has nothing whatsoever to do with benefits.

168 It would also be important here to take into account the many other factors that would influence generator's locational investment decisions, in practice. In most cases, transmission pricing differentials are likely to have relatively little impact upon where and when generators invest. Generators may instead decide to locate their plants based primarily on the availability of certain fuels, such as access to fossil fuel, geothermal or wind energy. For these types of generators, the locational variation in access to energy sources may greatly exceed even the largest feasible locational differentiation in transmission charges. In these circumstances, transmission charges have little or no effect on overall economic efficiency. Provided the price of these external factors is determined in competitive markets, we can assume that those prices reflect the marginal cost of the relevant inputs. Any resulting locational incentive arising from those input prices is therefore efficient and can be put to one side. *See:* Green H., *Economic Review of TPM Options Working Paper, A Report for Transpower*, August 2015, pp.55-56.

169 Electricity Authority, *Nodal pricing and LRMC charging*, p.4.

First, it is unrealistic to think that Transpower could wait until a theoretically optimal 'trigger point' to undertake a perfectly sized investment. Transmission capacity cannot be added in 1MW increments overnight. New transmission assets are lumpy, exhibit substantial economies of scale and require years of careful planning and lengthy approval processes. Transpower is planning today the investments that it might need to undertake in ten or twenty years.

Second, the potential repercussions of Transpower building something too small or too late are far worse than those associated with building something too big or too soon. The Commission established this clearly when it reviewed the weighted average cost of capital (WACC) percentile in 2014. Its economic advisor, Oxera, estimated that the potential cost of a single transmission outage arising from inadequate investment could give rise to economic costs in the vicinity of $3b:[170]

The economic costs of building 'too small' or 'too late' dwarf the costs of building 'too big' or 'too soon'.

> *'…**a cost in the order of NZ$1– NZ$3bn is considered to indicate the scale of the cost of network outages that could occur as a result of underinvestment**. Specifically, this is likely to represent an estimate of the scale of the annualised impact of such underinvestment, should it lead to increased network outages, or the potential size of a severe one-off effect.'* [our emphasis]

If Transpower decided to delay investing in new transmission assets and this resulted in a single major outage, then the result could be calamitous for customers – and New Zealand as a whole. In other words, simply 'waiting longer' for nodal prices to increase further as congestion worsens is neither an efficient nor a practical solution to the problem described in section 3.2. It would involve disregarding the fundamental economics of providing transmission services that cannot reasonably be ignored by the supplier of an essential service.

The second proposition is to augment nodal prices so that they do, in fact, incorporate the missing signal. This is essentially the antithesis of the first suggestion. Namely, instead of waiting for nodal prices to rise to the point at which they are signalling LRMC (which would risk the types of adverse outcomes described above), the idea would be to incorporate the missing signals *directly into* spot prices to plug the gap. There is nothing wrong with this concept in *theory*, but there are several practical factors to consider.

Augmenting nodal prices would be complex and costly. And the Authority has not done the work to explore the option.

First, augmenting nodal prices would be an enormous undertaking. It would be an extremely complex exercise that would change fundamentally the way in which the New Zealand electricity market functioned. The design and implementation costs would be substantial. For example, as Frontier Economics highlighted in its advice to the Authority's predecessor in 2009, the informational and predictive requirements of setting charges based on the augmented nodal signals approach would be considerable:[171]

170 Oxera, *Input methodologies, Review of the '75th percentile' approach, Prepared for the New Zealand Commerce Commission*, 23 June 2014, p.44.

171 Frontier Economics, *Identification of high-level options and filtering criteria, A report prepared for the New Zealand Electricity Commission*, September 2009, pp.24-25.

'… it would be necessary to develop a theoretically efficient transmission grid in which lifetime constraint and loss rentals recovered the fixed costs of the grid. It would then be necessary to determine the difference between the theoretically efficient nodal prices and the nodal prices that prevailed in practice. These differences would be used to derive transmission charges that would augment the prevailing nodal pricing signals. The difficulties of constructing such augmented nodal prices need to be weighed up against the benefits of imposing such differentiated transmission charges, which in turn will depend on the extent to which the transmission network is overbuilt by comparison to strict economic efficiency criteria.'

Second, the fact is that the work that would be needed to assess the merits of such an approach has not been done. This has not been through lack of opportunity. Frontier Economics' advice was provided over a decade ago. The TPM review has also been running for more than seven years, and the Authority has had more than two years since its last paper to develop such an option and subject it to a CBA. It has not done so. There is therefore no basis to presume that augmenting nodal prices would be a superior approach to introducing an additional LRMC-based price signal of some description – or, indeed, to any other pricing option. Statements to the contrary are unsubstantiated contentions.

If nodal prices were sufficient to provide efficient price signals the TPM would become an exercise in pure ex-post cost allocation.

Finally, it is worth recognising that if augmenting nodal prices or waiting longer for them to rise were viable options and, indeed, the most efficient approaches, then it is not obvious what role the proposed BB charge would be performing. In either case, nodal prices would be providing *all* the signals that grid users would need to see to make efficient decisions. Nodal prices would be eliciting efficient short-run usage decisions *and* facilitating the right investments at the right times. This is the scenario contemplated in section 3.1 and gives rise to exactly the same paradox, i.e., the BB charge would serve no purpose.[172]

In any event, despite touching upon both of these options in the consultation materials, the Authority ultimately has not recommended either approach. Rather, as we mentioned earlier, it has suggested that the BB charge can complement nodal prices by encouraging grid users to take account of the impact of their own consumption and investment decisions on the cost of new grid investment.[173] These implicit shadow prices are therefore said to supply the missing price signal – a claim we examine in section 3.4.1.

3.3.4 Introduce an LRMC-based charge

The overarching purpose of an LRMC charge is relatively straightforward and uncontroversial. Namely, it is to signal to users the cost of potential future grid expansions that might not otherwise be reflected in nodal prices. However, as Axiom's previous report explained in detail, although the principle is simple enough, there are numerous ways to design and implement such a price in practice.

[172] Namely, there would again be no need for any *ex-ante* price signals in the TPM. The only role for the TPM would be to allocate and recover the costs of investments in the least distortionary manner possible once they have been made. The best way to achieve that outcome would be via a broad-based tax – more akin to the proposed residual charge.

[173] Third Issues Paper, p.217.

Before an LRMC charge could be introduced, various choices would need to be made regarding:

There are many ways in which an LRMC charge might be applied.

- the methodology with which it would be calculated, e.g., whether to use a perturbation approach, an average incremental cost approach, etc.;
- the 'specificity' of the charge, including:
  - the geographic areas over which it would be calculated, e.g., for each node, for the four RCPD regions, for broader geographic areas, etc.; and
  - the period over which it would be measured (e.g., 5-years, 10-years, or longer) and how often it would be updated; and
- whether it would be applied to load, generation or both.

The decisions that are made in relation to each of these key design options would have a profound influence over key factors such as the 'accuracy' of the resulting long-run price signals, the pattern of prices over time, the complexity of the methodology and the ease with which it could be accommodated alongside other charges in the TPM. The potential variations on each of these design points – and on the LRMC-based charge ultimately derived – are infinite.[174]

As we observed in section 2.3.1, throughout its qualitative assessment of LRMC pricing, the Authority goes to great lengths to highlight the uncertainties, complexities and potential inaccuracies associated with the methodology. The Authority concedes that although it considers that there is potential merit in an LRMC charge, more analysis – including quantitative cost benefit analysis – would be needed before it could be recommended. Then, without actually doing the suggested investigative work, it concludes that:[175]

The challenges and uncertainties associated with LRMC pricing can clearly be overcome.

> *'Even if LRMC can be estimated robustly, it does not seem practical to establish how big the peak charge should be and when it should apply. On the contrary, **there is a very real risk of getting it wrong** in ways that reduce efficiency below that which would be achieved without any such charge.'* [our emphasis]

Nobody would deny that there are challenges associated with estimating LRMC robustly and with designing appropriate prices. Indeed, some of these are described above and in previous Axiom reports.[176] But these issues can be managed. Indeed, there are countless examples of regulators adopting the methodology in regulatory settings all over the world. It is therefore difficult to understand how an

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174 For example, in their report to the CEO Forum, Green *et al* (2009) proposed that an LRMC-based methodology might be applied to up to seven pricing zones, based on a simplified network topography. They also recommended the adoption of a 20- to 30-year period, which would serve to 'smooth out' the typical 'saw-tooth' movements in LRMC. *See:* Green *et al* (2009), *New Zealand Transmission Pricing Project: A report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, Figure 5.2, pp.12 and 74.

175 Third Issues Paper, p.218. See also the similar quotes set out in section 2.3.1.

176 Transpower has also released a report by Sapere Research Group that stepped through in some detail the practical implementation issues that would need to be addressed before implementing an LRMC charge. *See:* Sapere Research Group, *Issues to consider in designing an LRMC pricing regime*, A report for Transpower, August 2017 (available: here).

economically orthodox approach can be dismissed simply on the basis that there is a 'real risk of getting it wrong'.

As we intimated in section 2.3.1, if this same threshold was applied to the preferred option (which we examine subsequently), then it too would need to be rejected. In our opinion, there is a substantially greater risk of the Authority's proposal causing inefficiencies, given its untested nature and the lack of solid economic foundations. Yet, the risk of estimating certain things incorrectly did *not* discourage the Authority from recommending the BB charging approach (wrongly, in our view). It stated simply that:[177]

> *'Even with a* ***high degree of approximation****, we consider that the benefit-based charge would still provide much better incentives for grid users than is possible under the current guidelines.' [our emphasis]*

An LRMC-based approach could be an effective way of supplying the 'missing price signal'.

For those reasons, we remain of the opinion that a LRMC-based price might yet prove to be an effective way of providing the 'missing price signal' described earlier. The criticisms levelled at the methodology throughout the consultation documents are either misguided or apply equally – often more so – to the preferred approach. In our opinion, it would consequently have been fitting for the Authority to have spent some of the last two years developing-up *at least one* LRMC-based alternative and including it in the CBA – consistent with the recommendation contained in its own LRMC paper.[178]

3.4 The Authority's proposal

The BB charge is said to be able to provide an efficient 'shadow price signal'.

Having considered and rejected the widely-accepted, economically orthodox solution to the 'missing signal' problem described in section 3.2 – namely, an *explicit* LRMC-based charge – the Authority turns instead to an option that is both unconventional and internationally untested. Specifically, it proposes to elicit desirable behavioural change via the implicit 'shadow price signals' that it says would be supplied by the BB charge. As we explained previously, the Authority has claimed that BB charges are:[179]

> *'… intended to promote efficient investment by grid users,* ***by encouraging them to take account of the impact of their own use and investment decisions on the cost of new grid investment****.'* [our emphasis]

The proposal also provides an option for Transpower to introduce a 'transitional peak charge' over the next five years, to operate alongside nodal prices, at specific points in the grid that would otherwise experience congestion.[180] The Authority has made it clear that, in its view, this charge will not be needed in the long-term, since new demand response arrangements and the introduction of real-time pricing (and

177 Third Issues Paper, p.142.

178 Electricity Authority, *Nodal pricing and LRMC charging*, p.2.

179 Third Issues Paper, p.217.

180 Third Issues Paper, p.17.

scarcity pricing) would eliminate the need for that additional signal. In our opinion, this proposal is profoundly flawed from an economic perspective.

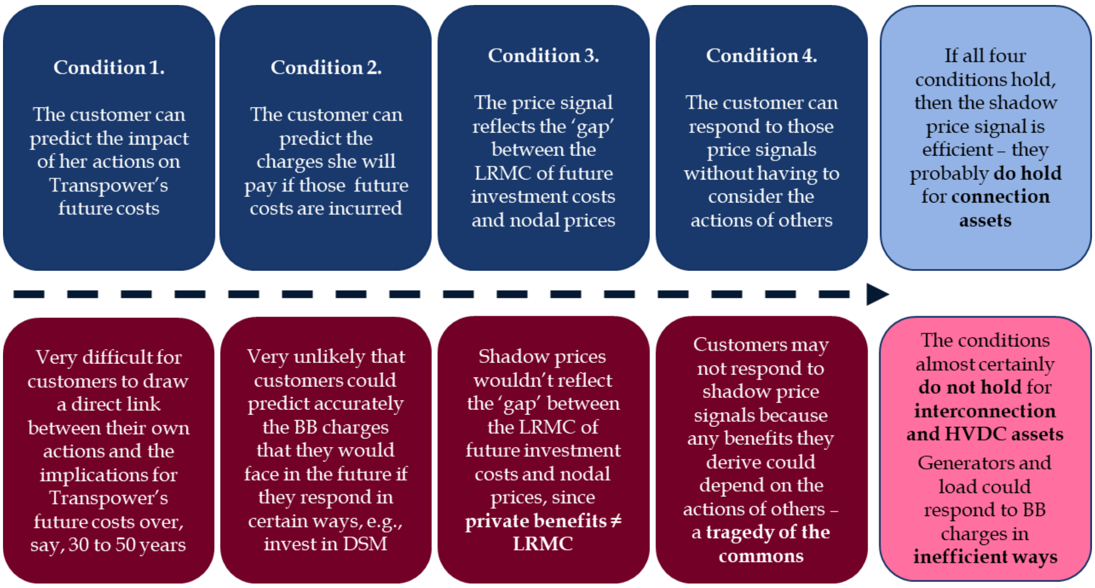
3.4.1 The BB charge would not work as intended

Before we recap the Authority's shadow pricing theory, it is worth briefly reminding ourselves of the irreconcilable contradiction in the analysis of the BB charge. A great deal of the Third Issues Paper is spent extoling the supposed virtues of nodal prices, which are said (wrongly) to provide customers with all the forward-looking price signals they need to see. Yet, other parts of the paper speak about the beneficial forward-looking signals that the BB charge would provide. By definition, these two propositions cannot both be right.

A shadow price can only provide an efficient price signal in certain conditions – none of which are met here.

In this case, both of these claims are *wrong*. We have seen already why nodal prices cannot 'do everything' and BB charges would not serve as a useful complement. The BB charge would not provide an *explicit* additional signal to customers of the long-term cost of future investments that is not captured in nodal prices. Instead, any signalling would be only *implicit*. Previous Axiom reports[181] have identified the four conditions that must hold before an implicit price can provide an efficient forward-looking signal. They have also explained why these criteria do not apply in the case of the BB charge. Figure 3.3 summarises these findings.

Figure 3.3: The conditions for an efficient shadow price do not hold



The basic premise of a BB charge is that, when deciding when and how to use the grid, customers would take into consideration the impacts of their actions on Transpower's future investment needs. They would then make a further inference regarding the future BB charges that they would face under various scenarios and, if

181 *See:* Axiom Report on Supplementary Consultation Paper, pp.14-20; and Axiom Report on Supplementary Consultation Paper, pp.17-21.

Most customers would not be able to draw a clear link between actions they take today and the effect on future costs and their BB prices.

appropriate, 'rationally self-ration'. However, it is not reasonable to assume that customers would be capable to drawing those links; for example:

- most customers would not be able to predict with any real accuracy the BB charges that they would face over the 40- to 50-year life of a transmission asset under all the different potential 'states of the world';[182] and
- as we noted in section 2.1.2, even the Authority acknowledged as much in its Distributed Generation Consultation Paper, i.e., in another context it conceded that such complex judgements would be beyond most customers.[183]

Even if all customers could make such inferences (which is implausible), no explanation has been offered as to why they would be inclined to respond efficiently given the potential for tragedies of the commons. When faced with the choice of continuing to use the grid in the same way or switching to a more-costly substitute that may defer an investment if others do the same, a customer might rationally conclude that it is not worth the risk. For example (using simple numbers):[184]

Customers may rationally choose not to take efficient actions, since the benefits they receive from doing so may depend on the actions of others.

- a customer might assess that if she spent $100 on distributed generation – and that others did also – that this could defer transmission costs and provide her with a private benefit of $200; but
- before the customer would be willing to spend the $100, she would first need to be confident that there was a greater than 50% chance that other customers were going to respond in kind; because
- if the probability of others responding in this way was below 50%, then the expected value of the future private benefit would be less than the near-term cost she would incur embedding generation, i.e., $100 x 100% > $200 x 49%.

Even if these other problems did not exist, the BB charge would still be fundamentally flawed because it would be sending the *wrong price signals*. Any implicit price signals provided by BB charges in conjunction with nodal prices would be inefficient, because they *would not reflect long-run costs*. While the LRMC of expanding the grid in a particular location may fluctuate over time, at any point in time it is a single, unique number[185] that is agnostic to *particular customers*, i.e., LRMC does not change depending upon whom the charge is being levied upon.

182 Axiom Report on Supplementary Consultation Paper, pp.15-17.

183 Electricity Authority, *Review of distributed generation pricing principles, Consultation Paper*, 17 May 2016, Appendix E.2-E.3.

184 An analogy to consider is a bridge into a central business district that was becoming heavily congested during rush hours, causing residents to face the prospect of higher rates bills to fund the addition of new lanes. Even if a motorist realised that she was contributing to the congestion problem and that she would pay higher rates if the bridge was widened, that does not mean that she would stop using the bridge during rush hours. She might determine that her own actions would make no difference and that, even if she did decide to delay her commute or use an alternative route that other motorists would not do likewise, which would render any efforts on her part obsolete. If enough motorists thought this way, then a tragedy of the commons could arise. A solution to this would be to place an explicit 'toll' on the bridge for those using it during peak times. This would be analogous to the LRMC charging approach described in section 3.3.4.

185 Note that the number itself may differ depending on the methodology with which it is calculated, but each approach will always yield a single number.

In contrast, the BB charge would provide an array of *multiple* implicit shadow prices for each future investment that reflected individual customers' perceived shares of private benefits. All of these could be above or below the *true* LRMC of transmission. The result would be *non-cost-reflective price signals* that could provide customers with inefficient incentives. For example, imagine that 'customer A' perceives that she will derive twice the 'private benefits' of 'customer B' from a forecast new investment:

The shadow price that each customer perceived would not signal the LRMC of transmission.

- with an explicit *ex-ante* LRMC-based price, this would not affect the size of the price signal that each customer would face – it would be *the same* for both, irrespective of their projected 'future private benefits' because, after all, the LRMC is a single number; whereas
- under the proposed BB charge, the shadow price faced by 'customer A' (assuming she can predict it) would be twice as high as that faced by 'customer B', providing the counterintuitive signal that a demand response from her is worth twice as much – when, in truth, the LRMC is *exactly the same*.

Moreover, even if shadow prices would be predictable and efficient, the likelihood is that the vast majority of customers would *never see them.* It seems very unlikely that final retail customers would ever be exposed to those prices. Firstly, there is no obvious way for distribution businesses to pass-on those implicit signals to retailers via their distribution charges, since they relate to costs that have not yet been incurred. A distributor would therefore need to predict what its future prices might be and then fashion an explicit price signal to retailers – neither of which seems very probable.

Even if shadow prices would be predictable and efficient, the vast majority of customers would never see them.

Importantly, those retailers' total distribution bills *would not increase*, since distributors could only pass-through transmission costs that they were actually incurring – not implicit future charges. And even if distributors structured the explicit charge in a way that incentivised, say, reductions in demand during peak periods (if, for the sake of argument, that was what the shadow prices was signalling), there is no guarantee that those price signals would be passed-on to final retail customers. Indeed, as the Authority has explained, most retail customers are on contracts that smooth-out these fluctuations.

Finally, it is worth reiterating that the potential benefits that might flow from removing or recalibrating the RCPD charge – if it is indeed 'too strong' – should not be conflated with the benefits (if any) associated with introducing the BB charge. As we noted earlier, it is quite conceivable that there may be some allocative efficiency benefits to be obtained by incentivising more usage during peak periods if there is spare capacity throughout the grid at present. But introducing a BB charge is not the only way to achieve that outcome and, in our view, it is far from the best.

As we explained above, the same near-term outcome could be achieved by replacing the RCPD and HVDC charges with a single, non-distortionary charge on load, or with a LRMC-based charge.[186] However, even though the short-term benefits

186 In fact, based on the Authority's analysis (which we explore in more detail subsequently), the same benefits could arguably be achieved by allocating the costs of new transmission investments

emphasised by the Authority could be achieved with many different methodologies (many of which would clearly be inadvisable), not all those approaches could deliver efficient long-term outcomes.

As we explained above, in time, demand would grow, and constraints would start to emerge more regularly throughout the grid. And when that happened, the BB charges proposed by the Authority would not incentivise customers to respond efficiently, because the price signals would be *inefficient.* At that point, any short-term allocative efficiency benefits that had arisen from the removal of the RCPD charge would be outweighed by the dynamic inefficiency costs.

3.4.2 Even if the BB charge worked as intended it would still be inefficient

The previous section explained why the BB charge would not function in the manner envisaged by the Authority, which would give rise to substantial dynamic and allocative inefficiencies. But even if the charge worked in exactly the way that the Authority has said that it would, it might still give rise to potential inefficiencies. The first thing to recall is that, according to the Authority's theory, the BB charge comprises two distinct prices.

Even if the BB charge worked as intended it might still be highly distortionary.

The first is an *explicit* price (i.e., real dollars and cents) that is applied to investments *after* they are made. This is levied as a fixed charge to *stop* customers from responding to it, i.e., to discourage them from changing their consumption behaviour in inefficient ways. It is therefore, in essence, a type of 'residual' charge – it is intended to be non-distortionary (like an 'efficient tax').

The second price is the *implicit* 'shadow' price that, according to the Authority, would provide a signal to customers *before* investments are made that would cause them to account for those upcoming costs. As we explained in the previous section, the contention is that these implicit price signals could elicit desirable behavioural change. Figure 3.4 below summarises these two price signals.

Figure 3.4: Two prices in one charge

The BB charge comprises two distinct prices.

The Issues Paper states that…

Before investments are made the BB charge would elicit **desirable** behavioural change

- It would send an efficient implicit 'shadow price signal' to customers to which they would respond, e.g., by curtailing demand to avoid the charge
- This would then remove any need to provide an *explicit* price signal, e.g., through an LRMC charge or the existing RCPD charge

After investments are made the BB charge would stop **undesirable** behavioural change

- By levying the charge as a fixed sum, customers would have little incentive to change their consumption behaviour to reduce their charge
- Because the charge would – in theory – be no greater than any customer's private benefit, this would remove any incentives to disconnect inefficiently

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entirely at random – say, by picking shares 'out of a hat'. The only criterion would be that any costs be recovered via non-distortionary prices, e.g., through fixed charges.

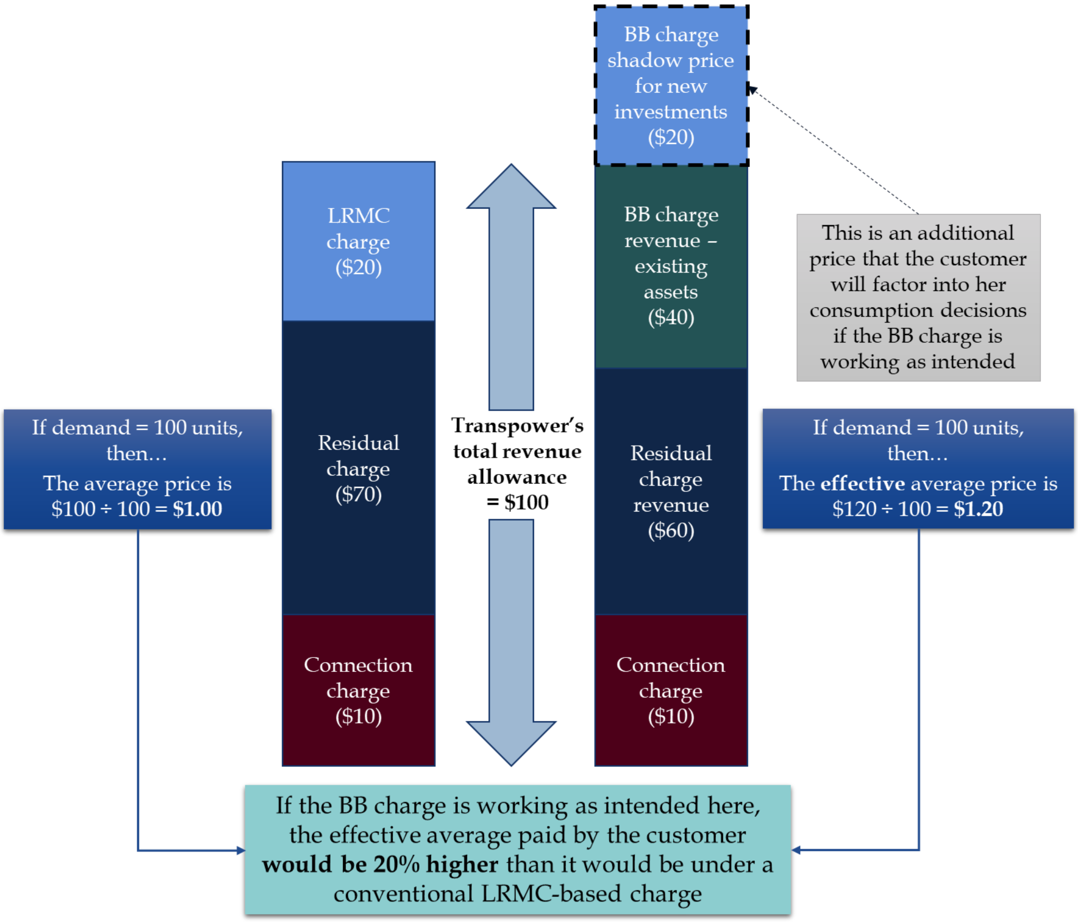
A potential problem with the BB charge is that, assuming it works as intended, it would result in higher *effective* average electricity prices, due to the *additive* effect of the implicit price component. This can be illustrated most effectively using a simple example. Let us assume that Transpower has an annual revenue requirement of \$100 (to keep things simple). Imagine also that there is only one customer consuming 100 units per annum (to make things simpler still).

Let us compare and contrast two transmission pricing approaches. As Figure 3.5 illustrates, with the first, the customer pays a connection charge (\$10 in total annual revenue) and an explicit LRMC-based charge (\$20 in total revenue). The fraction of the revenue requirement (the \$100) that is not recovered via these charges is then recouped via a non-distortionary residual charge (\$70). The average price per unit over the course of the year is therefore \$1.00 (\$100 ÷ 100).

The second approach is an approximation of the Authority's proposal. The customer again pays a connection charge (\$10 in total annual revenue). But this time, the additional explicit charges are a BB charge for existing assets (\$40 in total revenue) and the residual charge needed to recoup the remainder of the revenue requirement (\$60). Collectively, these explicit charges (i.e., real dollars and cents – not implicit charges) are sufficient to cover all of Transpower's annual costs (i.e., the \$100).

Figure 3.5: If BB charges work as intended 'effective' prices will increase

The shadow price element would increase the effective overall price since it would be in addition to the other explicit charges.



However, as Figure 3.5 illustrates, if the BB charge is functioning as intended, those explicit price signals are not all that the customer would factor into her decisions.

She would also take account of the *implicit* price signal. In this example, this is assumed to be the same strength as the explicit LRMC price (which, in reality, would not be the case, since benefits and costs are not synonymous[187]). This implicit price is *in addition* to the other explicit prices that would, between them, deliver-up Transpower's entire annual revenue requirement (i.e., $100).

The total *effective* sum that the customer faces is therefore equal to the $100 in explicit charges (the 'real money') *plus* the additional $20 in implicit charges (the total 'shadow charges'). The net effect is that the *effective* average price is $1.20 ($120 ÷ 100), i.e., 20% higher than in the scenario in which an explicit LRMC-based charge is applied. Of course, one might potentially respond to this by pointing out that, at the margin, the *incremental* price signal is the same.

Namely, in the example above, the LRMC charge and the implicit shadow price are *the same strength* (each delivers up $20 in revenue). It might therefore be tempting to conclude that the total and average price differential does not matter, i.e., that the customer's consumption and investment decisions would be the same in each case. Or, to put it slightly differently, one could argue that the 'fixed price' components of the customer's bill do not matter – it is only the variable charges that affect decisions, i.e., the fixed charges do not affect anything of consequence.

The only way that there could be no distortion is if customers do not respond at all to changes in fixed charges, which seems highly unlikely.

But in our opinion, such contentions would be misguided. It is undoubtedly true that variable charges would affect consumption and investment decisions more acutely than fixed charges. But it is unrealistic to think that increasing the level of fixed charges – and, in turn, total effective prices – would have no effect on consumption and investment outcomes whatsoever. In more technical terms, it is unlikely – perhaps even implausible – that the long-term price elasticity of demand in response to fixed price changes is *zero.*[188]

Moreover, as we explain in section 5.2.3, BB charges would not necessarily be 'fixed' in any case. Rather, there are numerous potential instances in which the allocation of benefits could be revisited – including when there had been a 'substantial and sustained change in grid use', a change in the regulatory WACC and so on. It is therefore possible – likely, even – that Transpower would be constantly revising BB charges as circumstances evolved – introducing a high degree of variability into those prices over time.

In other words, increasing fixed charges would have at least some effect on consumption and investment decisions – and not a beneficial one. For that reason, even if one assumes that the BB charging approach would function as intended (which, in our view, it would not), the inflationary impact that it would have on *effective* prices would be a cause for concern. In our opinion, it is conceivable that these increases would have distortionary impacts on both consumption and

187 As we explained in the previous section, this represents a crucial shortcoming in the Authority's shadow pricing theory.

188 For example, this could be because higher fixed charges would reduce the income available to spend on variable charges, i.e., the so-called 'income effect'.

investment decisions – none of which have been factored into the Authority's assessment – including its CBA.

3.4.3 Transitional peak price

In our opinion, the proposal to allow Transpower the option of introducing a transitional peak price signal is difficult to comprehend. As we have explained previously, the Authority has presented two incompatible theories in its Third Issues Paper; namely:

If nodal prices and/or the BB charge would work in the manner contended by the Authority, then any additional peak price would be pointless.

- that nodal prices are sufficient by themselves to deliver all the prices signals that customers need to see (see section 3.1); and
- that BB charges would provide customers with an *additional* efficient implicit forward-looking price signal (see section 3.4.1)

We have explained already why these propositions are both wrong – and irreconcilable with one another. But setting that to one side, in neither scenario should there be a role for a transitional peak charge. If nodal prices or BB charges (depending upon which theory is under consideration) are sending efficient forward-looking price signals, why would an additional peak signal be needed – even if only for a short period? If the theories are robust (which, in our view, they are not), it should be unnecessary.

In other words, if nodal prices or the BB charge – depending upon which theory is being proffered – would work in the ways contended, then any additional peak price would be pointless. All it would be doing is amplifying a signal that, according to the analysis in the Third Issues Paper, would already be pitched perfectly. Introducing an additional peak price signal should therefore result in a signal that is stronger than it should be.

It follows that the only circumstances in which an additional, explicit price signal would be needed is if nodal prices or the BB charge would *not* function in the ways that the Authority imagines. The very fact that it has seen fit to provide the option could suggest that it has some reservations about the signalling properties of these prices. In our opinion, any such doubts are more than justified. As we explained previously, nodal prices are not sufficient by themselves to send efficient long-term signals, and the BB charge would *not* work in the manner proposed and, even if it did, substantial inefficiencies would still result.

If nodal prices and/or the BB charge would not work as contended, then an explicit price signal is needed as a permanent feature.

In other words, an explicit price signal like an LRMC-based price is not a logical *complement* to the BB charge within the TPM – it is *superior substitute* for it. It makes no sense to use them in conjunction with one another and, once the substantial shortcomings in the proposed approach are recognised, the justification for having a BB charge at all falls away.[189] The proposal to limit the life of any such charge to five years is similarly challenging to understand. If anything, it would be more important to have such a change *beyond* this timeframe.

189 As we explain in more detail subsequently, the additional benefits said to arise from the charge (e.g., superior engagement in investment processes, improved durability, etc.) are not credible.

As we mentioned above, if there is currently significant spare capacity throughout the grid, then the optimal 'additional' price signal might oftentimes be very low – or perhaps even zero. However, that may change in the future – i.e., beyond the 5-year horizon – once grid constraints start to emerge more frequently. Once one recognises that neither nodal prices nor a BB charge would deliver efficient forward-looking price signals at those time, then it becomes apparent that the biggest benefits from an explicit peak price signal are likely to arise over that *longer* time horizon.

The reason that has been offered for limiting the initial timeframe to five-years is also perplexing. It is claimed that new demand response arrangements and the introduction of real-time pricing (and scarcity pricing) would, in time, eliminate the need for that additional signal. This rationale is problematic for at least two reasons. First, it is not at all obvious why these factors would address the 'missing signal' problem described in section 3.2. It is not even assured that scarcity pricing will be introduced or what form it would take if that happens.

If nodal prices were sufficient to provide efficient price signals the TPM would become an exercise in pure ex-post cost allocation – a BB charge would be unnecessary.

Second, if these matters truly could address the 'missing price signal' problem then we are back to the scenario that we encountered in section 3.1. Namely, nodal prices (with a scarcity component) would suddenly be providing *all* the signals that grid users would need to see to make efficient decisions, including by engaging in improved demand response. These factors would be eliciting efficient short-run usage decisions and allowing the right investments to be made at the right times.

That being the case, there would not need to be any other *ex-ante* price signals in the TPM – not from an explicit peak price or an implicit BB charge. It would be futile to try and elicit further responses from grid users via the TPM, since this could only compromise static and dynamic efficiency. Instead, the only role for the TPM would be to allocate and recover the costs of investments in the least distortionary manner possible once they have been made. As we have explained previously, the BB charge would have no role to play in that process.

However, in our opinion, the factors identified by the Authority would *not* give rise to perfect short- and long-term price signals, thereby turning transmission pricing into an exercise in non-distortionary cost allocation. Moreover, the rationale that the Authority has cited for its proposed BB charge – most notably, its shadow pricing theory – indicates that it thinks likewise. For all those reasons, the transitional peak price does not sit comfortably within the proposed framework. Rather, the package as a whole lack coherency.

3.5 Summary

In its two most recent consultation documents, the Authority has claimed that there is no need for an additional *ex-ante* price mechanism to be included in the TPM to prevent inefficient investment. Nodal prices have instead been said to be sufficient in themselves to efficiently ration the demand for existing transmission grid assets *and* give rise to the right long-term investment decisions.[190] Taken at face value, this creates two irreconcilable contradictions; namely:

- it is impossible to reconcile what the Authority is saying now with what it has said in past papers, where it has stated unambiguously that nodal prices *do not* provide efficient long-run investment signals; and
- if what the Authority is contending was correct then, by definition, the proposed BB charge – which would provide an additional implicit price signal – would be unnecessary and inefficient.

In reality, the Authority's statements about the properties nodal prices are *not* accurate. Although those prices can play a vital role in incentivising efficient short-term grid usage decisions, the basic economics of transmission mean that they do not signal adequately long-run investment costs. For customers to be made aware of the consequences of their actions on Transpower's *future* costs *before* they are incurred, something more is needed. The TPM consequently has a potentially important role to play in 'plugging this gap'.

The Authority considers and dismisses a number of options – including the LRMC-based pricing approach employed frequently by regulators throughout the world (and even adopted by distribution businesses here in New Zealand). As we noted above, it does so in large part because it claims – incorrectly – that nodal prices can fulfil the desired role. Having arrived at that erroneous conclusion, it then proposes to implement a BB charge that it says *would* elicit desirable behavioural change via implicit price signals. The basic premise is that:[191]

- when deciding when and how to use the grid, customers would consider the impacts of their actions on Transpower's future investment requirements; and
- they would then deduce the future BB charges that they would face under various scenarios and, if appropriate, 'rationally self-ration'.

This proposal is mysterious because, as we noted already, if nodal prices alone can be relied upon to elicit efficient long-term investment decisions, then why would there need to be an additional signal provided by the BB charge? Tautologically, nodal prices must either be sufficient to render redundant *all* additional price signalling methodologies – i.e., LRMC, RCPD, BB charges, etc., – or none of them. For the reasons set out above, the answer is the latter, since nodal prices do *not* signal adequately long-run investment costs.

The question therefore remains: what is the best way to provide that additional signal? In our opinion, the proposed BB charge is *not* the best solution – or a solution *at all* for that matter. Rather, it is deeply flawed from an economic perspective, because:

- the implicit *ex-ante* 'shadow price' signal provided by the BB charge would not provide a predictable, accurate signal of Transpower's long-run costs to which

190 *See for example:* Supplementary Consultation Paper, p.5; and Electricity Authority, *Transmission Pricing Review, LRMC charges, Working paper,* 29 July 2014, p.29.

191 Third Issues Paper, p.217.

grid users could respond – even if they were inclined to do so, i.e., it would not work as intended; and

- in the highly unlikely event that BB *did* function in the way that the Authority has described, the net result would be an increase in the effective prices that customers paid for transmission services, which could lead to inefficient distortions to consumption and investment decisions.

The inclusion of an optional five-year transitional peak-price is also hard to fathom. If either nodal prices or BB charges would work in the (contradictory) manners suggested then, logically, any additional peak price would be unnecessary and counterproductive. And if such a charge *would* be needed (because neither nodal prices nor BB charges would function as claimed) then, logically, it should be a *permanent substitute* for the BB charge, not a temporary complementary element. In short, this element of the proposal does not make sense.

More generally, the proposal as a whole – and the analysis underpinning it – is unbalanced and, in several respects, incoherent. We consequently continue to think that for grid users to face an efficient signal of the potential future costs of investments in the interconnected grid, there must be an *explicit ex-ante* price signal. This might be a variant of the existing RCPD and HVDC charges, or a new LRMC charge. The proposed BB charge would be a poor substitute and give rise to myriad potential distortions, as we explain in the following section.

4. Effects on consumption and investment

In this section we consider in more detail how the BB charge might affect customers' consumption and investment decisions. We also examine whether introducing the proposed methodology would be likely to give rise to more constructive engagement in grid investment decision processes.[192]

4.1 Effects on decisions by load

The paper states that one of the principal problems with the interconnection and HVDC charges is that they provide poor *ex-ante* price signals, which incentivise inefficient use of the interconnected grid. In particular, the RCPD-based charge is said to incentivise load shedding (e.g., through distributed generation), even though there is now significant spare transmission capacity throughout much of the grid. The proposal is said to address these potential problems.[193]

The Third Issues Paper suggests that the shadow price signals would lead to efficient consumption and investment by load customers.

The theory underpinning the BB charge is that, when there is spare capacity, customers would be encouraged to use the grid because the shadow price signal would be relatively weak. But, as the time for new investment approaches, the signal would strengthen, incentivising demand curtailment. In other words, it is said that the shadow price would result in load making efficient consumption decisions through time, by taking into account the future consequences of their actions on Transpower's investment requirements.

The Issues Paper also claims that any such improvements in the efficiency of consumption decisions would, in time, result in more efficient investment decisions by both Transpower and load customers. In particular, the Commission would not be called upon to approve an investment that could have been avoided through efficient demand curtailment. In our opinion, the BB charge is unlikely to offer these advantages, in practice. Instead, it would risk incentivising inefficient consumption and investment decisions.

4.1.1 Effects on usage when there is spare capacity

We agree that the proposed reform would be likely to remove any incentive that load customers might otherwise have to reduce their use of the transmission grid during peak periods when there is spare capacity. However, as we have noted on several occasions already, this outcome would not be achieved through the *addition* of the BB charge. Any such outcome would be more appropriately attributable to the *removal* of the existing *ex-ante* price signals from the TPM – namely, the signal currently being provided through the RCPD charge.

192 Note that the material set out in this section is taken largely from Axiom's report in response to the Authority's second issues paper. *See:* Axiom Report on Second Issues Paper, pp.24-30.

193 Note that for the purposes of this section we are taking the economically orthodox position that nodal prices alone cannot incentivise efficient long-term investment. As we have noted previously, the Authority's analysis is internally contradictory in this respect, because it oscillates between saying that nodal prices can be relied upon to deliver *all* necessary price signals and contending that BB charges have an important role to play in providing *additional* signals.

If the proposal was implemented, and load shedding stopped, it would not be because load customers were implicitly assigning very low 'shadow prices' to the *future* BB charges that they might have to pay. It would be because there would no longer be any financial benefit to them from curtailing demand once the RCPD-based price was no longer there. Any benefits would therefore stem from having *no* peak-demand-based price signal – not because of the introduction of a new BB charge. The same benefits could be obtained by:[194]

Removing the RCPD charge would stop inefficient load shedding, not introducing the BB charge.

- removing the BB charge from the proposed methodology and retaining simply the broad-based residual charge on load;
- replacing the BB charge with an LRMC-based charge and retaining the residual charge on load (or some other non-distortionary 'tax'); or
- in the extreme, allocating costs purely at random via a lump-sum tax (e.g., drawing transmission customers' annual allocations 'out of a hat').

Moreover, by removing the RCPD-based charge, the proposal would take away the only *explicit* price signal that Transpower has at its disposal under the current TPM to incentivise load shedding when capacity constraints *re-emerged in the future*. As we explained in the previous section, and in more detail below, a shadow price would not be effective for this purpose. The potential consequence of this could be inefficient consumption decisions and, in turn, inefficient investments.

4.1.2 Effects on usage when capacity is constrained

One of the advantages of retaining some form of the existing RCPD-based interconnection charge – or introducing an LRMC-based charge – is that it would enable Transpower to send a signal – albeit an imperfect one[195] – to customers to curtail their usage during times of peak demand as capacity constraints start to emerge in a region. For example, under the status quo, reducing the number of periods over which RCPD was measured – from 100 to, say, 12 – could provide a strong incentive to manage load.

Removing the RCPD charge would prevent Transpower from efficiently signalling future constraints.

It is relatively straightforward to see how the current RCPD-based charge, or an LRMC-based price could result in more efficient grid usage in these circumstances. Specifically, a customer would ask herself: "is there something that I could do to reduce demand – such as invest in distributed generation – that would cost me less than what I am likely to pay under the interconnection charge if I do not respond?" If the answer to that question is 'yes', then:

- the customer will rationally seek to avoid the charge (e.g., by investing in distributed generation or demand-side management), confident that it will be financially beneficial for her to do so; and

194 In all of these cases, parties would have little or no incentive to reduce consumption during peak periods to specifically avoid transmission charges which, given the current point in time in the investment cycle, could well deliver a positive net benefit.

195 Sections 3.3.2 and 3.3.4 described some of the limitations of the RCPD charge and the design and implementation challenges associated with LRMC-based pricing.

- if that type of response is sufficiently widespread amongst market participants, it may push back the time at which Transpower has to incur those future costs, resulting in broader market benefits.

In contrast, the BB charge would *not* provide load customers with efficient incentives to curtail demand because, as we saw in the previous section, the key conditions for efficient shadow prices do not apply to interconnection assets. The price signals provided under the BB charge would be difficult to estimate, would not reflect the 'gap' between nodal prices and LRMC[196] and customers may be unable or disinclined to respond to them. The potential consequence would be inefficient consumption decisions and, in time, inefficient investment.

4.1.3 Effects on investment

We agree with the basic principle espoused in the Issues Paper that more efficient grid usage can be expected to result in more efficient investment. However, it is unlikely that the price signal provided by the BB charge would promote dynamic efficiency in this manner. That is because the prices are likely to produce *inefficient* consumption decisions from load, which would give rise to the very outcomes that the Issues Paper is seeking to avoid. Specifically:

Because the BB charge would not lead to more efficient usage by load, it would not lead to more efficient investment.

- in the future, load customers may *not* curtail their demand when it is efficient to do so and the Commission may find itself approving a new grid investment that appears to be efficient, given current and forecast demand; when
- this may be overlooking the fact that the underlying peak demand growth that was driving the investment was itself inefficient, i.e., it could be reduced by replacing the implicit prices with a more efficient price signal.

In other words, because load customers would not see an explicit, forward-looking price signal reflecting Transpower's future investment costs, they may not curtail demand when they ideally should. That could lead to Transpower undertaking new investment sooner than it otherwise would if customers had been provided with a coherent cost-reflective signal via, say, the RCPD charge or a LRMC-based peak price. The BB charge would not lead to this effective rationing.

The same inefficient price signals might also cause load customers themselves to make inefficient investment decisions. For example, they may over- or under-invest in distributed generation, in response to price signals that may be inefficient, that have been misunderstood, or have been ignored because of the potential responses of other customers (i.e., because of tragedies of the commons). Finally, the charge would have little effect on where load customers chose to locate.[197]

196 Although, as we explained in section 3.3.2, the RCPD charge may not reflect LRMC either.

197 The locational investment decisions of load customers are unlikely to be affected in any meaningful way by differences in transmission charges in the overwhelming majority of cases. Residential consumers do not decide where to live based on relative transmission charges and major industrial loads like aluminium smelters and pulp and paper mills can be expected to locate where they have access to key inputs such as deep-water ports and forestry resources.

4.2 Effects on decisions by generators

One of the key differences between the existing TPM and the approach proposed in the Third Issues Paper is the greater number of charges that would be levied upon generators. Currently, all generators pay connection charges and South Island generators pay HVDC charges. Under the proposal, generators would continue to pay connection charges, but *all* generators would be eligible to pay BB charges – and possibly a transitional peak charge, if such a price was introduced.

The Authority states that requiring generators to pay BB charges would provide them with more appropriate incentives when making investment decisions. The theory is that generators would factor the implicit BB prices into their investment choices when, under the status quo, transmission costs would be ignored (with the exception of connection and HVDC charges). In this section, we consider the impact of BB charges on generator's decisions and nodal prices.

4.2.1 Potential effects of an efficient price signal

Levying additional transmission charges on generators would increase their costs and result in higher wholesale prices.

Levying an additional fixed charge on generators would increase the average expected wholesale electricity price required to make most new generation investments commercially viable.[198] This may serve to delay the point at which new generation plant comes online – or change the 'build order' which would, in turn, result in wholesale prices that are higher than would otherwise have been the case. Of course, that would not be problematic if those decisions were being made in response to an efficient, cost-reflective price signal of long-run transmission costs.

Specifically, a generation 'build order' in which the plants took into account an accurate estimate of the forward-looking costs of transmission might be more efficient from a 'whole of system' perspective than a schedule in which generators had not had to account for those costs (because they do not have to pay for them).[199] This can be illustrated using a simple example.

Imagine that there are four generators: A, B, C and D. In the absence of any transmission price signal, they would be built in that order, i.e., Gen A has the lowest build cost, Gen B the second lowest, and so on. However, two of the generators, A and C, are located in 'area 1' and the others, B and D, in 'area 2'. The LRMC of transmission is significantly higher in area 1, but the same for both plants located there.

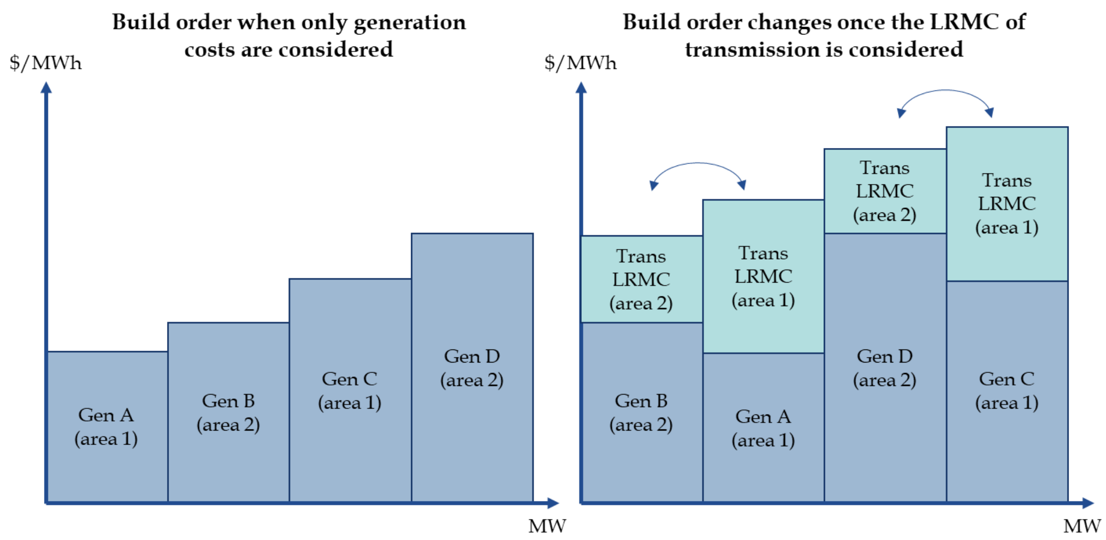
Figure 4.1 illustrates that if those generators are required to pay a transmission charge that reflects the difference in the LRMC of transmission across the two areas, the build order changes. The higher LRMC of transmission in area 1 causes the

198 Specifically, it would increase a new generator's 'break-even' points, i.e., it would render a generator that was only marginally profitable under the existing TPM, unprofitable. Wholesale electricity prices would therefore have to increase to cover existing generators' higher costs. This is consistent with what one would expect to observe in any competitive market when input prices increase, i.e., those higher costs are passed through to some degree.

199 Although recall that, for the reasons set out in footnote 168 above, transmission costs would probably have no bearing on these decisions, most of the time.

plants located in area 2 to be built sooner than they would otherwise have been without that explicit signal. Note that we have assumed here that the transmission price signals are accurate (i.e., reflective of the gap between SRMC and LRMC discussed in section 3.1) and known to all.

Figure 4.1: Theoretical improvements to the generation 'build order'



In these circumstances, application of a cost-reflective transmission charge would lead to higher wholesale prices to cover the additional costs that generators would face. However, the idea is that the increase in wholesale prices would be *more than offset* by the *transmission cost savings* that arose from the superior locational investment decisions, resulting in a *lower total cost of delivered energy*, e.g., the 'total cost' of Gen B is less than the total costs of Gens A, C and D.

In our opinion, there is nothing wrong with this theory *per se*. However, the analysis in the Issues Paper (and the CBA) hinges upon one critical assumption – namely, that the BB charge would be sending an *efficient* price signal to generators. As we have seen already, *it would not*. It follows that levying BB charges on generators could have significant adverse effect on their investment decisions, giving rise to *higher* delivered energy prices for consumers. We elaborate below.

4.2.2 Potential effects of an inefficient price signal

Levying BB charges on generators would not provide them with efficient price signals.

Assuming that a new generator could predict accurately the BB charges that it would pay (which it most likely could not), the proposed methodology would signal to it that its impact on the long-run cost of transmission would be correlated perfectly with the private benefits it would derive from that investment. However, this does not reflect the way in which new generators may affect Transpower's long-run costs. By way of simple illustration:

- the long-run impact on Transpower's future investment costs of connecting a 100MW peaking plant that will run for 10 hours a year might often be much the same as the impact of a 100MW combined cycle gas turbine (CCGT) unit that will run for 8,000 hours a year; yet

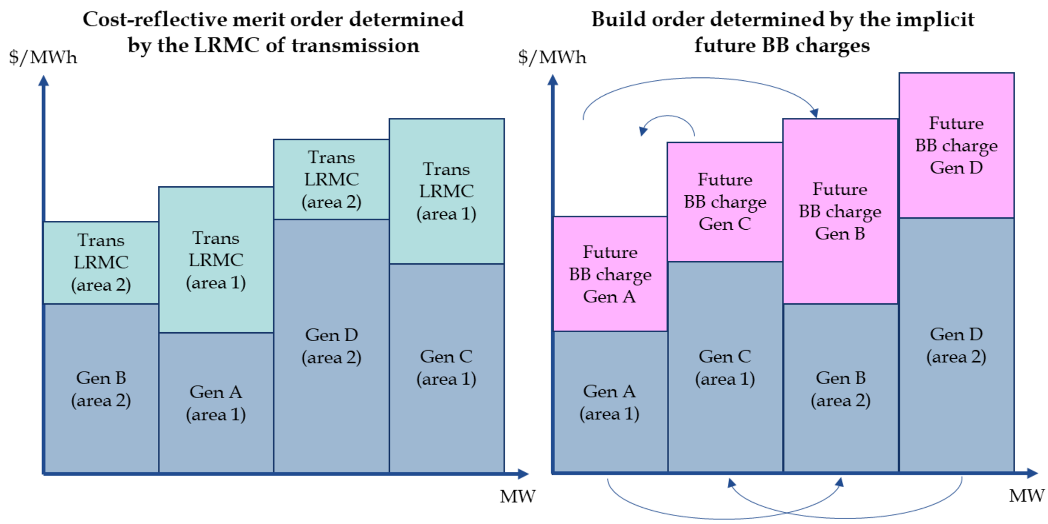
- the private benefits that those two plants might derive from a future investment might be very different, i.e., despite their equivalent impact upon the long-run cost of transmission, their respective BB 'shadow prices' might vary greatly.

This is simply another symptom of the fundamental problem we described earlier: private benefits are *not synonymous with long-run costs*. It therefore does not make sense to try and provide these types of BB price signals to customers. Even if generators could successfully 'decode' those implicit signals, they are not the right messages to send in the first place. They would be providing *unique signals* to each generator – none of which may correlate with future costs. This may give rise to perverse outcomes.

To see why, let us return to our earlier example of the four generators (A, B, C and D) investing in areas 1 and 2. Recall that the LRMC of transmission in area 1 (where Gens A and C are considering building) is *higher* than in area 2 (where Gens B and D are thinking about investing). If that difference in LRMC is signalled efficiently to the generators, the build order depicted on the left of Figure 4.2 emerges. However, the Authority's BB charge may yield something entirely different.

The inefficient shadow price signals could distort generator's investment decisions.

Figure 4.2: Potential distortions to generation build decisions



For the reasons set out above, the price signals that the four generators would all face under the proposed BB charge could all be unique and bear no resemblance at all to the LRMC of transmission in each location, i.e., the *efficient* price signal. Because each generator responds to its own bespoke – and potentially highly inefficient – implicit BB price, the build order could be distorted substantially. The build order on the right of Figure 4.2 illustrates.

Compounding these problems, the proposed TPM guidelines state that large consumers or generators who connect *after* an investment has been made – or that establish new large plants or additional generating units – must be assigned a share of the costs of sunk interconnection assets. The guideline does not specify how those costs should be assigned. It states simply that the TPM must provide a process for making such allocations.[200] The potential for unwelcome distortions here is obvious.

Depending upon *how* BB charges are assigned to new generation customers, it might affect the size and/or nature of the plant that is installed, e.g., a generator might decide to install a smaller plant to avoid paying a higher BB charge. It may also cause new entrant generators to build in sub-optimal locations. Indeed, it is hard to imagine how Transpower could allocate shares of sunk costs to new entrants *without* compromising the efficiency of entry decisions. This is a further manifestation of the basic problem described above; namely:

- a new entrant might be deemed to derive significantly greater private benefits from the interconnection assets located in 'location A' than 'location B', which would incentivise it to locate in the former, all other things being equal; but
- the impact the generator has on Transpower's future investment costs may be the same in both locations or it may even be preferable for it to build in location B – which might not be signalled, for the reasons already discussed.

Yet another distortion is created by the differential treatment of certain *existing* investments. The Authority has proposed to apply the BB charge to seven existing interconnection and HVDC assets. With the exception of the HVDC link, all of these investments were built after 2004 and had approved values of over $50m.[201] The overall effect of imposing this cut-off is to improve the economics of generation investments undertaken in areas supplied predominantly by assets built before 2004, i.e., where the grid tends to be older.[202]

The distinction between pre- and post-2004 would create an additional distortion.

Regardless of whether assets are old or new, their costs are sunk. The proposed approach would impose an arbitrary 'tax' on investments in locations where assets are newer than average. This would be economically nonsensical and could only give rise to dynamic inefficiency. More generally, as we explained in section 2.2.2, we are not aware of any international transmission pricing arrangements that involve the reallocation of past sunk costs.

Box 4.1: Properties of the RCPD and BB charges

It is worth noting briefly here that one of the criticisms that the Authority has levelled repeatedly at the RCPD charge is that it generally increases after Transpower has invested in the grid to increase capacity.[203] This is said to be inefficient, since prices should ideally *drop* when spare capacity is available following new investments. There are some clear problems with this criticism, especially when it is set alongside this aspect of the proposed BB pricing methodology; namely:

200 Proposed TPM Guidelines, clause 42.

201 Third Issues Paper, p.120.

202 Although we note that under the Authority's proposal Transpower does have the option of extending the application of BB charges to more existing assets if it wishes to do so.

203 Third Issues Paper, p.8.

The BB charge exhibits the same characteristic as the RCPD charge.

- when Transpower invests in new assets, its total revenue requirement increases, so existing prices either have to increase, or new prices must be introduced, i.e., it needs to recoup its entire revenue requirement; and
- Transpower *has reduced the strength of the RCPD peak signal* to reflect the increased grid capacity (by increasing the number of periods over which it is measured from 12 to 100 in the upper North and South Islands).

But even more fundamentally, the BB charge would *also* result in new entrants facing higher prices immediately after new investments had been made, i.e., *exactly the same supposed problem* that the Authority identifies with the RCPD charge. As we noted above, this would be particularly problematic when it comes to new generators deciding when/where to invest since the BB charge is, in effect, a variable charge for those entrants.

For all of these reasons, in our view, the price signal that would be provided to generators via the BB charge would be likely to have an adverse effect on their investment decisions that would compromise dynamic efficiency. These inefficiencies would result in higher wholesale energy prices and, in turn, more expensive retail prices for end customers. As we explain in more detail in section 6.3.4, none of these factors have been considered in the CBA.

4.3 Effects on the grid investment process

The Authority continues to contend that charging parties based on the benefits they are estimated to receive from investments might lead to more constructive engagement in the approval process, giving rise to more efficient outcomes. Previous Axiom reports[204] have explained extensively why that is unlikely to be the case. The Authority has not addressed those points. In short, the theory does not represent the practical context in which the new investment approval process takes place. In our opinion, introducing a BB charge would not have a beneficial effect on these proceedings – it would be more likely to have a negative impact.

4.3.1 No evidence of past inefficient investments

Past Axiom reports have highlighted that no relevant material has been provided to suggest that the Commission's input methodology (IM) has led to inefficient investment outcomes – or that it might do so in the future if a BB charge is not introduced. The Authority has sought to address that criticism in its Third Issues Paper by identifying three past investments that it says are 'likely' to have been inefficient. It states that:[205]

> *'There are examples of likely inefficient grid investments. When analysing the benefits of the post-2004 large historical grid investments (those with costs exceeding $50 million), to*

204 *See:* Axiom Report on Second Issues Paper, pp.30-32; Axiom Report on Supplementary Consultation Paper, p.39; Green *et al*, *Economic Review of EA Beneficiaries-Pay Options Working Paper*, A Report for Transpower, March 2014, pp.27-30; and Green H., *Economic Review of TPM Options Working Paper, A Report for Transpower*, August 2015, pp.28-33.

205 Third Issues Paper, p.255.

identify benefit-based charges, we were not able to identify net benefits for three of the investments: North Auckland and Northland (cost $473 million), Otahuhu GIS (cost $106 million) and Upper South Island dynamic reactive (cost $55.2 million). These investments were all approved by the Electricity Commission. While we note the benefit calculations we have conducted for these investments were historical and only considered benefits early in the lives of these investments, the lack of net benefits at this point raises questions around the efficiency of the timing of construction at the very least.

That several such major investments — with a total cost of more than $500 million — may have costs exceeding benefits confirms there are legitimate questions about whether the transmission pricing regime is fit-for-purpose, and effective in supporting the transmission investment approval regime.'

The three past investments identified by the Authority have not been shown to be inefficient.

We understand that at the Auckland TPM workshop the Authority stated that its vSPD methodology had indicated that the North Auckland and Northland (NAaN) investment had delivered *no benefits at all* between 2014 and 2018 (despite it having found significant benefits in past papers using the same approach[206]). We are informed that this was presented as an example of why the TPM supposedly needs to change. In our opinion, the modelling has not demonstrated that at all. On the contrary, it has yielded results that raise more questions than answers.

It does not seem plausible that Transpower could have spent $473m on a network investment that delivered *zero* benefits over this four-year window. Some would even say that it was impossible. Taken literally, what the Authority's results are suggesting is that customers would have been no worse off over this period if Transpower had simply disconnected the link. In our opinion, the more logical explanation is that the Authority's methodology is not capturing all the benefits that the investment is delivering.[207]

The Authority is suggesting that customers would have been no worse off if Transpower had disconnected the NAaN assets from 2014 to 2018.

The most obvious category of benefits that the methodology might be missing is reliability and resilience benefits. All three projects labelled 'inefficient' were *reliability* investments deemed necessary to meet grid standards. The most valuable benefits arising from these types of investments do not manifest in day-to-day operations. For example, having extra redundancy in the grid is not going to reduce nodal prices the vast majority of the time. In that sense, it is perhaps unsurprising that the vSPD approach has produced the results seen in the paper.

Those reliability investments become most valuable *when something goes wrong*. For example, the N-1 deterministic standard means that, when something major fails, the grid has been built with enough tolerance to stop the lights going out. For example, the chief benefit of Orion's investments in earthquake proofing did not materialise until disaster struck. If the Authority's vSPD approach had been used to

206 *See:* Electricity Authority, *Transmission pricing methodology review: Beneficiaries-pay options Working paper*, 21 January 2014, p.110; Electricity Authority, *Transmission Pricing Review, TPM options, Working paper,* 16 June 2015, pp.82-83; Second Issues Paper, p.214.

207 The Authority acknowledges – albeit only in a footnote (number 187) – its analysis spans only a short historical snapshot of the relevant assets' lives. Just because the costs appear to exceed the benefits during this period – which, in all cases, is relatively early-on in the assets' lives – does not mean that far greater advantages would not be forthcoming in later years when demand has grown. However, this is a minor problem compared to the methodological issues discussed below.

assess the efficiency of those investments *before* the earthquakes, it might well have determined – wrongly – that they had been wasteful (see Box 5.1 in section 5.2.2).

The Authority appears to have violated the proscription against hindsight and has not accounted for all the relevant benefits.

Second, is important to remember that when assessing the success of the investment framework one must avoid the 'proscription against hindsight'. The efficiency of decisions must be judged in light of the information that was available at the time that they were made, and *not after the fact*. To quote a US regulator:[208]

> *'A prudence review must determine whether the company's actions, based on all that it knew or should have known at the time were reasonable and prudent in the light of the circumstances which then existed. It is clear that such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the [commission] to merely substitute its best judgment for the judgments made by the company's managers.'*

Two of the investments flagged by the Authority – Otahuhu GIS and Upper South Island Reactive Support – received final approvals in late 2007.[209] This was mere months before the onset of the global financial crisis (GFC), which resulted in a significant flattening of load growth. When viewed *shortly after* that time, it is quite possible that these investments might have appeared unnecessary or untimely. However, the critical point is that neither Transpower nor anyone else could have anticipated the effects of the GFC *when the investment decisions were made*.[210]

Overall, in our opinion, applying the vSPD approach to assess the efficiency of historical reliability investments is therefore a flawed exercise. It cannot shed any light on whether the right investment decisions have been made, because it ignores some of the most important categories of benefits. The implausible results the Authority has produced for the NAaN investment is evidence enough. It is the logical equivalent of an airport concluding that it was 'inefficient' to have invested in firefighting and safety services, because there had not yet been any major incidents during which they had been called upon.

The benefit allocations contained in Schedule 1 of the proposed TPM guidelines are not robust.

One crucial consequence of this is that the allocations set out in Schedule 1 to the proposed TPM guideline, which Transpower would be required to apply when setting BB charges for existing investments, are not robust. All those allocations would have been afflicted with the methodological problem described above, i.e., a failure to account adequately for crucial benefits arising from improved resilience and reliability. These would not have manifested in nodal price outcomes, unless major incidents had occurred.

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208 *In re Western Mass. Elec. Col.*, 80 PUR4th at 501, See: Phillips (1993) *The Regulation of Public Utilities* 3rd ed, Arlington Virginia, Public Utilities Reports, Inc, p.340.

209 A final decision on the North Auckland and Northland upgrade was made on 30 April 2009.

210 Incidentally, even if the Authority's analysis was appropriate, it is unclear to us why the three investments should be excluded from the application of BB charges in their entirety. The logic underlying the Authority's proposal (flawed though it may be) would suggest that Transpower should allocate a sum equal to the total value of private benefits via BB charges, and then seek to recover any shortfall via the residual charge. After all, that is what would happen if a similar scenario arose for a future investment, i.e., BB charges would recover what they could, and the residual charge would recoup the rest

4.3.2 Many other practical points have been overlooked

The Authority's theory hinges on an assumption that if it introduces a BB charge, beneficiaries would 'come out of the woodwork' and engage fulsomely in grid investment approval processes, allowing the Commission to make better decisions. However, this overlooks a number of practical points that undermine the contention that there are substantial benefits on offer from improved scrutiny. For example:

The Authority has overlooked a number of obvious points that undermine its contentions regarding greater investment scrutiny.

- The regulatory regime applying to Transpower operates such that, once a regulatory allowance is set (and is thus 'sunk'), Transpower has an incentive to spend efficiently – additional scrutiny at the allowance setting stage is not obviously going to affect that incentive or the investments that it subsequently elects to undertake.
- During that allowance setting process the Commission itself has:
  - every incentive to scrutinise proposed investments;
  - significant information gathering powers that it can use to obtain the materials that it needs (powers which customers *do not* have); and
  - extensive experience reviewing such proposals that it can bring to bear.

  It is consequently hard to see how consumers and generators could match the Commission's effectiveness at finding efficiency-based reductions to Transpower's projected investments.
- Even if consumers and generators could be as effective as the Commission – which is doubtful – the Authority's theory assumes that they would be able to find *further* significant efficiencies in projected investments *beyond* those that the Commission would itself find, which does not seem very credible.[211]
- Although some interested parties may have a greater incentive to scrutinise investment, others may have less (e.g., because they are no longer affected by the investment), and others may be influenced by free-rider effects (where it is often easier to rely on others to scrutinise investments than to expend time and effort engaging directly).
- Even if additional scrutiny did lead to reduced projected and actual investment for a given regulatory period (which is unlikely for the reasons set out above), then at least some of those reductions could reflect efficient deferrals of investments into subsequent regulatory periods. This would, in turn, reduce the scope for finding reductions in those later periods.

A potentially useful 'sense check' of the Authority's claim is to consider the scrutiny that is typically afforded to the regulatory WACC when it is reviewed. This is perhaps the single most important determinant of the prices that customers

211 The Authority rightly recognises that the scope for finding efficiencies would differ across expenditure categories, depending on whether the Commission has looked at something or not. However, this misses the obvious point that the Commission's choice of which expenditure to investigate is driven by its experience and the likelihood of finding inefficiencies. Moreover, the Commission's statutory objective requires it to set efficient expenditure allowances. If there were obvious gains to be made from further scrutiny of Transpower's expenditure proposals, then the Commission would surely apply greater scrutiny itself to more effectively discharge that objective.

ultimately pay, yet stakeholder input is limited generally to the affected regulated networks or shareholders, large retailers, one or two national consumer representatives, and a handful of large users. It is hard to see proposed transmission investments attracting significantly greater scrutiny.

In other words, it still has not been established that there is a problem with the Commission's new investment framework that needs to be solved. Put simply, TPM reform cannot feasibly deliver the kinds of benefits that the Authority is envisaging – and certainly not the $77m sum that is has estimated in its CBA (which, as we explain further in section 6.4.2, is without any foundation). Moreover, even if there *was* a problem with the existing grid investment approval process, the Authority's proposed reform would be unlikely to improve matters.

4.3.3 The proposal would not improve the investment approval process

Under any conceivable variant of the TPM, there are likely to be submissions from parties that support an investment and those that oppose it – regardless of whether it is 'good' or 'bad'. That is because parties would not be motivated by what is best for the market. Rather, profit-driven enterprises would, quite understandably, want the outcome that delivers the most benefits *to them.* Even if an investment would be likely to maximise overall market benefits, there would inevitably be winners and losers. That would influence what parties would have to say to the Commission about any particular investment proposal:

The proposal would lead to more unhelpful opposition to investments.

- a party that is not a private beneficiary of a proposed investment (i.e., a loser) would be unlikely to take any solace in the fact that it maximises benefits for the market – it would oppose the proposal because of the negative wealth implications on its business (and its profits);
- even if a party would be a private net beneficiary of the investment (i.e., a winner) that would maximise overall market benefits, it may still have an incentive to lobby for something else that would deliver it even higher benefits, e.g., a smaller investment – or something built later; and
- all parties (winners and losers) would *always* have an incentive to say that investments would not benefit them as much as Transpower has said since, if those arguments were successful, their charges would be lower (and, as we explain below, benefit estimates would always be uncertain).

Irrespective of how the TPM is designed, the Commission will always have to weigh up a number of conflicting submissions – none of which will be motivated by maximising the net market benefit – and exercise its judgement. It will therefore invariably be its role to 'discover' the efficient transmission investment outcome. The TPM cannot short-circuit that process, and there is consequently no reason to think that the proposed reforms would have any bearing on the Commission's processes. The 'Auckland undergrounding' case study does not affect this conclusion, for the reasons set out in Box 4.2.

Box 4.2: Auckland undergrounding

The Authority has noted that there is currently some demand in Auckland to require the undergrounding of transmission lines. Overhead wires are far less visually appealing but, as the Authority has pointed out, underground lines are more costly. Neither Transpower nor the Commission considers wider environmental and aesthetic benefits when assessing undergrounding proposals and so, if a request was made to underground some of Auckland's lines, it is likely that it would be refused.

The Authority has raised the possibility that local councils might decide to change the local planning regulations to *mandate* undergrounding, knowing that, under the current TPM, Auckland consumers would only pay for part of the cost. It has suggested that, under its BB proposal, Auckland consumers would instead have to pay most or all of those costs, which might stop councils from modifying the planning regulations. However, there are a number of problems with this chain of logic.

The first thing to recognise is that it is only inefficient from a societal perspective for undergrounding to proceed if the total costs exceed the total benefits – including *all* amenity values. It might therefore be that the total benefits that would accrue to Auckland customers – including amenity benefits – would outweigh the total cost to Transpower. But because not all those social benefits are captured in the investment approval process, an efficient investment does not proceed. Changing the planning regulations might therefore *improve* dynamic efficiency in this case.

The 'Auckland undergrounding' case study does not provide a robust basis for reforming the TPM.

Of course, the scenario that the Authority has in mind is where the total costs of undergrounding exceed the benefits, but the total costs *facing Auckland customers* do not. But for that outcome to transpire it would need to be case that the local councils could – and would – ignore the costs that would be imposed on all other parts of the country. In our opinion, it is not clear that would be the case and, if it was, the obvious solution to that problem is to *change the planning regulations* to address that gap – not to reform the TPM.

That is because, although changing the TPM might address this one specific example (assuming there is indeed a potential problem), it would not work in all situations. That is because, although local councils can presumably be made to consider wider costs when making decisions, it is likely to be much harder for Transpower to place values of things like improved aesthetics when assessing the benefits of investments. By way of simple example:

- imagine that Transpower is proposing to build a new link to deliver generation from town A to load in town C;
- the link will also traverse town B, but it is not needed to serve load in that location, i.e., the customers of town B are not 'beneficiaries';
- the local council in town B decides that it does not want unsightly transmission towers along its streets, so it mandates undergrounding; and
- as a result of that decision, Transpower must spend, say, $10m more than it would otherwise have done absent those new local regulations.

When it came to assess the beneficiaries of the new link, would the customers of town B be required to pay anything? Probably not. Unlike in the Auckland undergrounding case study, the customers in town B are not really benefiting from either investment. So, unless Transpower seeks to estimate some form of incremental 'amenity' benefit (which seems unlikely), those customers would not pay for a share of either the cheaper link, or the more expensive one.

In other words, in this slightly different case study, a BB charge would do nothing to stop a local council from mandating undergrounding. In contrast, if the local council in town B was required to consider the wider costs of undergrounding (e.g., for customers in towns A and C) before making such a change, a potentially inefficient decision could be stopped. What might work in the Auckland scenario (assuming there is even a problem) therefore would not work in countless others that one could envisage.

Finally, there remains the simple fact that the Authority's case study is entirely speculative. The newspaper article to which it refers is from over two years' ago. If Auckland councils were willing and able to make the type of change that the Authority contemplates then they have had plenty of opportunity to do so. But they have not. In other words, even if there is a potential 'loophole' that might result in inefficient behaviour (which, as we explained above, is unclear), it is not being used.

The proposal could lead to more potential sources of opposition.

To the extent the proposal has any effect on the investment approval process, it could well be negative. For example, in some cases it might give rise to more unconstructive opposition to 'good' investments, which may actually make it harder for both Transpower and the Commission perform their roles. For example, when deciding whether to support any investment, a party would consider whether it might benefit more from something else, such as:

- a smaller investment that entailed lower costs; and/or
- an investment that took place at a later date when demand is higher, i.e., when it might be paying for a 'lower share' of the BB charge.

The potential beneficiaries of a 'good' investment may consequently oppose it, simply because they would benefit more from another option that offers fewer overall market benefits. The fact that the BB would seek to 'lock-in' beneficiaries once and for all after an investment has been made[212] would give rise to further problems, because:

- parties might recognise the potential for their *actual* benefits to differ markedly from the benefits that Transpower ascribed to them, due to the considerable uncertainties associated with that estimation exercise;[213] and
- these possibilities might make them more likely to agitate against investments from which they may benefit, simply because they fear the possibility of being burdened subsequently with a disproportionate share of the costs.

212 As we explain in section 5.2.3, there are some circumstances in which the BB charges applied to 'high-value' investments could be reallocated under the proposal. However, the Authority has explained that it expects such occasions would be 'rare'. *See:* Third Issues Paper, p.144.

213 The EA highlighted this risk in its first Issues Paper in 2012. *See:* Electricity Authority, *Transmission Pricing Methodology – issues and proposal, Consultation Paper*, 10 October 2012, paragraph 6.5.5.

The proposal could lead to less useful information being shared.

The introduction of a BB charge could also lead to *less* useful information being provided to Transpower and the Commission, not more. For example, customers are likely to hold their future investment and operating plans much closer to their chests (and/or intentionally understate them) if they expect that information might be factored into Transpower's net benefits calculations in ways that might lead to higher charges. This is the *opposite* of what the Authority is suggesting would happen if its proposal was implemented.

Parties would also be expected to focus unduly on the subjective assumptions that underpinned their own estimated private benefits.

Because the BB charge would require Transpower to estimate the benefits that parties are expected to derive from investments over its entire life (e.g., 40 to 50 years) it is also inevitable that parties would focus on the assumptions underpinning their respective benefit calculations. Because many of these would be intrinsically subjective, this would be a recipe for ongoing controversy and productive inefficiency.

We consequently remain of the view that the introduction of a BB charge would not result in the Commission being provided with more useful information during grid investment approval processes. Instead, it is more likely to create potential additional sources of opposition and lead to less useful information being shared, not more. It would also result in enormous emphasis being placed on subjective modelling assumptions that have disadvantaged particular customers. This would not aid the discovery of efficient investments – it would hinder it.

4.4 Summary

The benefits that are forecast to flow from introducing the proposed BB pricing approach would not eventuate, in practice. Instead, introducing the methodology would be likely to cause load and generation to respond by making *inefficient* consumption and investment decisions. The grid investment process would also be hindered significantly. Table 4.1 summarises.

Table 4.1: Potential inefficiencies arising from the shadow price signal

	Load	Generation
Usage	Because the key conditions for efficient shadow pricing do not hold, the BB charge would not enable Transpower to send efficient signals to customers to curtail demand when constraints start to re-emerge in the future.[214] This could result in Transpower having to invest to alleviate constraints sooner than it would otherwise have needed to if an explicit price signal had been sent to customers via the TPM.	Levying BB charges on generators would increase the costs of operating plant and, in turn their 'break-even' points. This would result in higher wholesale market prices to cover those higher costs or because of avoided / deferred generation investment. It is unlikely that those higher wholesale costs would be offset by long-term transmission cost savings because, as we note below, the BB charge would be unlikely to incentivise efficient new investment decisions.

214 Note that, although inefficient load-shedding would cease in the near-term if the proposal is implemented, this would be on account of the removal of the RCPD charge, not the introduction of

	Load	Generation
Investment	Levying BB charges on load customers is unlikely to affect their locational decisions since, in the vast majority of circumstances, other factors would have a far greater bearing. For example, residential customers do not decide where to live based on transmission charges, and the locational decisions of large industrial customers will generally be swayed by practical factors such as the location of forests, ports, workforce, etc.	Because the key conditions for efficient shadow pricing do not hold, the BB charges would not provide generators with an efficient price signal – especially because expected private benefits are not synonymous with forward-looking transmission costs. The proposal would also send the counterintuitive signal that it is cheaper for generators to locate where assets were built before 2004. This would compromise dynamic efficiency.
Engagement in grid investment processes	If the BB charge is introduced, it is likely to create more sources of dispute and generate incentives for parties to strategically withhold information. Customers would not share future operational/investment plans if this information might then be used to assign them a higher share of benefits. The requirement to recover the costs of an investment based on estimated private benefits over the life of an investment would serve to exacerbate the scope for disputes. Customers would naturally focus on modelling assumptions that have affected them adversely. This additional unconstructive opposition could compromise dynamic efficiency if it results in 'good' investments being blocked.	

The BB charge would therefore not elicit desirable *changes* in behaviour from customers. Any benefits would consequently need to reside in the charge's ability to minimise distortions to demand *after* investments have been made and/or to reduce productive inefficiencies arising from ongoing disputes and so on (i.e., to improve 'durability'). We consider these matters in the following section.

the BB charge – and there are many other ways to achieve that same outcome, e.g., via a LRMC-based charge.

5. Allocation of sunk costs

In Axiom's previous two reports, once it had been established that the proposed methodology would not provide an efficient forward-looking price signal, the focus switched to whether it might result in a more efficient allocation of sunk costs *after* investments had been made. The principal conclusions set out in those reports were the following:[215]

Previous Axiom reports concluded that the proposed methodology would not result in more efficient allocations of sunk costs.

- changing the way in which sunk costs are allocated by implementing a BB charging methodology would not necessarily improve allocative efficiency or, at least, not by any more than other more orthodox options; and
- the proposed approach would be likely to give rise to significant additional costs arising from the uncertainties and disputes that would result inevitably from the methodology, i.e., productive inefficiency.

As we mentioned earlier, the proposal has remained largely unchanged from the last paper and the rationales that have been presented are also much the same. Unsurprisingly therefore, the core conclusions that we have reached are also identical. In short, we continue to think that the proposed changes to the allocation of sunk costs would be neither efficient nor equitable. We elaborate below.

5.1 Allocative efficiency

Axiom's previous reports identified several key reasons why changing the way in which sunk costs are allocated by implementing the BB and residual charging methodologies would not necessarily improve allocative efficiency. For example, those reports highlighted the following:

- although any inefficient load shedding would cease if the proposal was implemented, this would be due to the *removal* of the RCPD charge, not the *addition* of a BB charge, e.g., an LRMC-based charge could do the same;[216]
- there were allocative inefficiencies arising from the HAMI-based parameter on the HVDC charge, but these have diminished significantly following the announcement and introduction of the SIMI-based parameter;
- the inefficient forward-looking price signals that would also be provided by the BB charge (the 'shadow-price' component) would serve to compromise the consumption decisions of both load and generation;[217] and
- the proposal to apply the depreciated historical cost (DHC) valuation approach to existing assets earmarked for BB charges was unnecessary and would have resulted in an inefficient time profile of prices.[218]

215 Axiom Report on Second Issues Paper, pp.34-44; Axiom Report on Supplementary Consultation Paper, pp.33-42.

216 Axiom Report on Second Issues Paper, pp.34-37.

217 Axiom Report on Second Issues Paper, pp.27-30.

218 *op cit.*, pp.40-41.

These points have not been addressed satisfactorily in the Third Issues Paper and, as such, they remain equally valid. This leaves open the possibility that the proposal would *reduce* allocative efficiency relative to more orthodox reform options. We explore these matters below.

5.1.1 The proposal would not promote allocative efficiency

The extent to which changing the way in which the sunk costs of the existing grid are recovered from customers can give rise to allocative efficiency benefits depends first and foremost upon the degree to which the current TPM is giving rise to unwelcome distortions. As previous reports have highlighted,[219] this depends upon the current level of inefficiently unserved demand, i.e., whether the current interconnection and HVDC charges result in:

- some parties not consuming as much of those transmission services as they would have at a price that reflected their private benefit; or
- some parties not consuming the services at all, i.e., refraining from consuming altogether because they are not willing to pay those charges.

There are two key potential sources of allocative inefficiency under the current TPM.

In these circumstances, demand that could have been served at prices that generate positive economic profits goes unmet, producing a deadweight loss. Any reduction in that deadweight loss must therefore come from an *increase in demand* from customers who *would not* have benefited from that consumption under the current TPM, but who *would* under the proposal. Put another way, the only way in which reallocating sunk costs can deliver an allocative efficiency improvement is if:

- some customers face *lower* prices than under the current TPM and consequently *increase* their consumption of transmission services; and
- those customers that face *higher* prices do not inefficiently *reduce* their demand, which would serve to undo the efficiency gains arising from the former.

This consequently begs the question: to what extent is there likely to be material unserved demand associated with the current TPM? In our opinion, there are two key sources of potential allocative inefficiency arising from the way in which the sunk costs of existing investments are recovered under the status quo – both of which are identified in the Issues Paper and the CBA. These are:

- the incentive created by the RCPD charge to shed load to avoid interconnection charges, even though there is currently spare capacity throughout much of the grid, i.e., total peak demand is generally below available capacity; and
- the potential inefficiencies arising from the Historical Anytime Maximum Injection (HAMI) charge applied to a proportion of HVDC assets, i.e., the incentives created for South Island generators to strategically withhold supply.

In terms of the first, as we have observed already, we agree with the Authority's observation that load customers may currently have undue incentives to reduce

219 See for example: Axiom Report on Second Issues Paper, pp.34-36; and Green *et al*, *Economic Review of EA Beneficiaries-Pay Options Working Paper*, A Report for Transpower, March 2014, pp.13-15.

their use of sunk interconnection assets so as to avoid RCPD charges through, say, the use of distributed generation. This is a potentially a source of static inefficiency, since there is currently spare capacity. Much of the demand that is currently being curtailed might therefore be served more efficiently by using the existing transmission grid assets.

It is not necessary to introduce a BB charge to achieve these allocative efficiency gains.

However, as we have already seen, the achievement of those allocative efficiency gains does not hinge on the introduction of the Authority's preferred option. In order to eliminate the existing inefficient level of unserved demand, all that needs to happen is to remove – or perhaps reduce the strength of – the existing RCPD charge. This could be achieved in several ways, e.g., by replacing it with an LRMC-based charge with a residual component. In addition to being more economically orthodox, an LRMC-based charge would not suffer from all the problems that would afflict the BB charge that have been described throughout this report.

The inefficiencies associated with the HAMI parameter that is still a feature of the HVDC charge (although becoming less so every year) were recognised by both Transpower and the Authority during the first TPM operational review. From 1 April 2017, the HVDC charge has therefore been gradually phased out and replaced by a South Island Mean Injection (SIMI) charge, which reflects South Island generators' total annual injection into the South Island grid, in MWh terms, averaged over the capacity measurement periods for the previous five pricing years.

In approving the change in methodology, the Authority observed that a SIMI-based charge would promote static efficiency for the long-term benefit of consumers, by reducing the incentive of South Island generators to withhold generation capacity. Even though the SIMI charge has not been fully phased-in, we understand that customers have already changed their behaviour in response to it, i.e., by offering more capacity.[220]

In other words, there is nothing that the proposal would do to discourage inefficient load-shedding that alternatives – such as LRMC-based prices with a residual charge – could not do at least as well or better. There also seems to be little, if any, work to be done to improve the static efficiency properties of the SIMI-based HVDC charge. In contrast, the BB charge in particular could *compromise* allocative efficiency by distorting the consumption decisions of load and generation customers in the ways described in sections 4.1 and 4.2.

5.1.2 The time profile of charges would be counterintuitive

Several of Axiom's previous reports have explained why applying a DHC valuation approach to set prices for bespoke transmission investments would yield an inefficient time-profile of charges.[221] Specifically, it would result in prices that were highest early on in an asset's life (i.e., when not much straight-line depreciation had been applied) and lowest right at the end of its estimated life when it was nearly

220 Axiom Report on Second Issues Paper, p.35.

221 *See for example:* Axiom Report on Second Issues Paper, pp.40-41; and Green *et al*, *Economic Review of EA Beneficiaries-Pay Options Working Paper*, A Report for Transpower, March 2014, pp.17-20.

fully depreciated and about to be replaced. This is the opposite of what efficient transmission pricing requires.

The Third Issues Paper has sought to address this 'time profile' problem for new assets by proposing that Transpower recovers the value of the commissioned assets in equal annual amounts over their lives.[222] The intention in these instances is to employ a methodology that would produce smooth prices throughout the life of the assets, which is more consistent with what one typically observes when a DHC approach is applied to an *entire regulated asset base* (rather than to specific assets).

However, the Authority has proposed to use the annual DHC values arising out of Transpower's individual price-quality path (IPP) when applying the BB methodology to set annual prices for the *existing* interconnection and HVDC assets that have been earmarked for the charge.[223] The principal reasoning underpinning this distinction is that departing from a DHC approach part-way through those assets' lives would supposedly risk customers paying more than the total costs of those investments. The Authority states that:[224]

There is no reason to think that applying a replacement cost approach to existing assets would result in 'over-recovery'.

> *'DHC recovers most of the cost of an investment in the early years of an asset's life, whereas IHC recovers relatively more later in its life. So using DHC for the start of the investment's life and IHC for the end could overall recover more that the total cost of the asset.'*

The Authority also notes that if the IHC and DHC charging profiles diverged, then this would have flow-on impacts for the quantum of revenue that would need to be recovered via the residual charge. In our view, this reasoning demonstrates a misunderstanding of the way that interconnection charges have been levied under the status quo. There is no reason to think that applying an IHC approach to existing assets would compromise allocative efficiency. But applying a DHC methodology would.

Firstly, insofar as the HVDC assets are concerned, the Authority's concerns are plainly misplaced. Transpower's IPP contains a specific HVDC revenue allowance, which limits the amount that it is permitted to recover for those assets under the TPM. So even though BB charges would be applied to both Poles 2 and 3, Transpower would *not* be able to set charges that resulted in it somehow 'over-recovering' the costs of those investments. That would not be possible, because its IPP would prevent it.

Secondly, there is no basis to think that customers might end up 'over-paying' for the interconnection assets that comprise the remaining investments, or that there would be attendant 'negative effects' on the residual charging element. The most important thing to realise is that Transpower has *not* applied bespoke interconnection charges for particular assets – including the six that have been flagged for BB charges. Instead, it has:

222 Proposed TPM guidelines clauses 14(a)(i) and 15(a)(i).

223 Proposed TPM guidelines clause 16.

224 Third Issues Paper, footnote 166, p.127.

- calculated the annual revenue that it must recover through the TPM – the majority of which comprises a return on and of the depreciated value of its regulatory asset base, which comprises *all* of its assets, old and new; and
- set RCPD-based charges for *all* of its interconnection assets, i.e., there is a single bucket called 'interconnection revenue' – there are not 'multiple buckets' that allocate the costs associated with particular assets to certain customers.

An IHC approach should be used for all assets subjected to the BB charge – including existing assets.

It is therefore not valid to ask whether applying an IHC valuation approach to specific assets would result in some customers 'overpaying' for those investments. Overpaying relative to what? There is no answer to this question, because there has *never been a price* for those individual assets under the TPM – it is consequently an irrelevant thought experiment. There have instead been prices that reflect the value of *all* interconnection assets, which have been paid by *all* customers. There is therefore no basis for the concerns expressed in the paper.

Thirdly, even if there was some reason to think that customers might 'over-pay' for those particular interconnection assets, in our view, that would still not necessarily be a sufficient reason to employ a DHC methodology. As the Authority has recognised, the total amount of revenue that Transpower would recover would not change, because that is set by the Commission (and independently of the TPM). All that would happen is that more of that revenue would be recovered via the BB charge, and less through the residual. For all of those reasons, we do not consider it to be necessary or efficient to apply a DHC approach to the existing investments earmarked for BB charges.

5.2 Productive efficiency

The Authority contends that its allocation approach would be fairer and more durable than the status quo. Axiom's earlier reports have highlighted why that is unlikely to be the case. In our opinion, introducing a BB charge would give rise to significant additional costs, i.e., to productive inefficiency.

5.2.1 It is the Authority that has created most of the uncertainty

The Authority concludes that the way in which the current TPM has allocated the sunk costs of past investments has not proved durable. This contention is predicated principally on its contention that, once the current TPM was introduced in 2008, a review of transmission pricing began 'almost immediately, leading to ten years' of uncertainty for the industry'.[225] However, this statement has the potential to mislead for several reasons.

Two TPM reviews commenced in mid-2009 – one by the Electricity Commission (EC) and the other by the New Zealand Electricity Industry Steering Group (to whom Axiom Director, Hayden Green, was a principal economic advisor). The latter focused primarily on the merits of introducing a 'tilted postage stamp' methodology. However, modelling by Transpower indicated ultimately that the net

225 Third Issues Paper, p.v.

benefits of introducing additional locational signals at that time would be small. The materials produced by the Steering Group were therefore handed over to the EC for inclusion in its review, i.e., the two processes were folded together.

That EC review – which then became an Authority review when the EC was disestablished – was, in turn, handed over to the Transmission Pricing Advisory Group (TPAG). That group produced a report[226] in June 2011 that recommended only modest changes to the TPM, e.g., transitioning the HVDC charge to a 'postage stamp' price. Put simply, the group found that the status quo was doing a reasonably good job and did not see the need for radical changes. The TPM was then settled for the ensuing sixteen months.

Then, despite the fact that a group of industry representatives had recommended only minor tweaks, the Authority released an Issues Paper (on 10 October 2012) proposing sweeping reforms, including the introduction of the untested 'SPD' methodology. As we explained in section 2, the ensuing seven years has seen a sequence of five similarly unorthodox and unprecedented proposals. Each of these proposals has been exposed subsequently as lacking sound economic foundations and none of them has been supported by a robust CBA.

The Authority is chiefly responsible for creating the uncertainty surrounding the TPM.

In other words, in our opinion, it is more reasonable to conclude that, prior to 10 October 2012, the TPM had been relatively stable. The extensive work of the two reviews that commenced in mid-2009 had concluded that, although the TPM was not perfect (which no pricing methodology ever is), there was no need for radical change. The main exception to this was the cost allocation enshrined in the HVDC charge. Since that time, all the uncertainty has been created by the Authority's review, which has fallen short of best regulatory practice in numerous respects.

For that reason, it is somewhat counterintuitive for the Authority to assert that a core benefit of its proposal ($26m) is 'increased certainty to investors'. In our experience, it is unusual – if not a little self-serving – for a regulator to assign a large benefit to clearing up the very uncertainty that it has created through its own actions. In this particular instance, improved durability could be obtained far more simply by the Authority stating categorically that it will be stopping its review and not contemplating any changes to the TPM for, say, the next ten years.

Or, by the same token, certainty and durability could be achieved by recommending a more orthodox, tried-and-tested methodology such as a variant of a LRMC-based price and a non-residual residual charge. In other words, the achievement of certainty is not linked inextricably to the implementation of the Authority's particular proposal. Quite the contrary. As we explain below, the proposed approach would neither lead to a more durable TPM nor improve certainty. In our view, it would be very likely to make things worse.

226 Transmission Pricing Advisory Group, *Transmission pricing discussion paper, For consultation,* 7 June 2011 (available: here).

5.2.2 The proposed approach would create even more uncertainty

Estimating accurately private benefits over the entire life of an interconnection investment would be impossible.

The proposed methodology would not be durable and would create additional uncertainty. As past Axiom reports have explained,[227] the primary reason for this is that it would be impossible for Transpower to forecast with any meaningful precision the temporal dynamics of private benefits over the 30- to 50-year (or thereabouts) life of an interconnection asset when deriving BB charges. There are numerous practical factors that would serve to complicate any such exercise. These complications include (but are not limited to) the following:

- if an investment is being sized so as to cater for potential future entrants, (e.g., if significant demand growth is forecast, or more generators are expected to connect at some point), it would be very difficult to factor those developments into the allocation of charges in any robust way;
- any private benefit analysis that was dependent upon future nodal prices would require assumptions to be made about how generators might bid into the market in the future – in our opinion, there is likely to be no robust way to mimic this type of market process through modelling;
- the extent to which a party benefits from an asset at any particular time would depend upon exogenous factors, such as whether it is a 'dry-year' or a 'windy-year', and so any analysis of benefits would need to take into account factors such as forecast hydrological conditions – an exercise fraught with potential for error; and
- in the case of *existing* assets (remembering that the Authority proposes to apply the BB methodology to some large investments made post-2004) there is the further substantial additional complexity of hypothesising what would have happened in the *absence* of the investments in question.

More complex approaches would not necessarily yield more accurate estimates, but they would give rise to many more costs.

In our opinion, these challenges cannot be overcome through the use of more sophisticated approaches to estimating private benefits – such as the vSPD method used by the Authority to come up with the indicative charges for 2022. Rather, more complex approaches may be no better at predicting the pattern of private benefits over 30- to 50-year periods than simpler approaches. While these approaches might seem more precise, in our view, that is largely false precision. More complexity does not necessarily mean greater accuracy.[228]

For example, as we explained in section 4.3.1, the vSPD method does not capture all the relevant benefits arising from investments. This is evidenced by the results that have been produced by the Authority's assessment of recent investments such as the NAaN project. As we noted above, the method suggested that *no* benefits accrued

[227] *See:* Axiom Report on Second Issues Paper, pp.37-39; Axiom Report on Supplementary Consultation Paper, pp.35-37.

[228] We note, for example, that the Midcontinent Independent System Operator (MISO) acknowledges these practical limitations in the variant of a BB charge methodology that it employs. Namely, only 80 per cent of the costs of qualifying new investments are allocated to the perceived beneficiaries (in 'Local Resource Zones') – with the remaining 20 per cent recouped via a system-wide postage stamp. This recognises the considerable margin for error that exists in estimating benefits, i.e., there is a 'downward adjustment' to cater for that uncertainty.

from that investment between 2014 and 2018. That does not seem plausible. The more logical explanation is that crucial categories of benefits – for example, reliability and resilience benefits – have been missed in that modelling exercise. The example in Box 5.1 illustrates.

Box 5.1: The vSPD method does not provide a complete picture

> Prior to the Christchurch earthquakes, the local electricity distribution business, Orion, made several investments in earthquake proofing. If the vSPD approach had been used to assess the efficiency of those investments *before* the earthquakes, it might well have determined – wrongly – that they were wasteful. That is because many of them would have had little – if any – influence on spot prices, i.e., removing those investments might have had no effect on the wholesale prices that prevailed during 'normal' operations.
>
> However, when disaster struck, those investments were invaluable. They meant that the damage was not as bad as it might have been, and they allowed Orion to 'get the lights back on' faster. It was *outside* normal operations that the investments delivered their most important benefits and revealed their true worth. The vSPD approach therefore only provides *part* of the picture. It does not capture the wide array of benefits that arise from transmission investments. So, whilst it might appear to be 'more accurate', it is not.

More complexity also means more administrative costs and, in all likelihood, more scope for disputes. For example, to apply the vSPD approach, Transpower would need to design and undertake a series of 'modelling runs' every time it built an asset valued $20m or more. In order to do so, it would need to come to a view on the various parameters set out above, including the value of lost load, forecast nodal prices, expected future demand growth and so on.

Complex approaches would give rise to more disputes than more pragmatic allocation methodologies.

Arriving at estimates of parameters would require subjective judgement, which could affect significantly the charges that different customers were assigned. Parties would therefore be expected to agitate continually for these assumptions to be changed, because they would know that even a small revision in their favour might significantly reduce their charges. This would lead to additional costs and, in turn, productive inefficiency.

It might be possible for Transpower to 'fix' *some* of the key modelling parameter values in advance for a period, e.g., five (perhaps even ten) years. However, that would neither improve the accuracy of the resulting benefit estimates, eliminate the potential for significant ongoing disputes, nor reduce the level of controversy and cost relative to the existing TPM, because:

- there would inevitably be substantial dispute over any initial values assigned to these modelling parameters, and the values assigned at each subsequent review, given the potential value at stake; and
- because any model would be likely to have significantly more constituent parts than the existing TPM (an inevitable consequence of using a complex quantitative model), there would be a wider 'potential set' of parameters over which there would be controversy when the TPM was set/revisited.

In any event, even if fixing modelling inputs in advance was an effective solution (which it is not), it would not be possible to lock-in every value. Taking the vSPD approach as an example, occasions would arise when the model could not be 'solved' with those pre-determined parameter values. Transpower would therefore need to have the flexibility to exercise its judgement when defining counterfactuals in order to produce a vector of prices. It could never become a simple 'crank the handle' exercise. Moreover, Transpower would also need to supplement any vSPD modelling with further analysis to capture the benefits that would otherwise be missed, e.g., reliability and resilience benefits (see Box 5.1).

The nature and effect of the judgements that Transpower would need to make to determine benefits may vary based on many factors, including the level of demand and other grid constraints. Every time Transpower had to make a 'judgement call', there would inevitably be winners and losers – and the losers would be expected to challenge those decisions if the sums in question were significant. This is especially so given that the idea would be to 'lock-in' those prices forever.[229] This would be a recipe for ongoing controversy, cost and productive inefficiency.

The Authority has stated previously that locking-in beneficiaries would not be a durable approach.

As we noted in section 2.1.3, when it was proposing instead the so-called 'SPD approach' in 2012 (which would have updated beneficiaries constantly over time), the Authority highlighted explicitly that measuring private benefits and then 'locking them in' would not be a durable methodology. It acknowledged many of the practical problems set out above. Recall that it stated that:[230]

> *'The approach proposed by Professor Hogan of applying beneficiaries pay involves determining the charge that would apply to parties prior to an investment, with the charge fixed over time. Although this approach has some merits, the Authority considers that a key difficulty with such a charge is* ***it is calculated on the basis of anticipated benefits rather than actual benefits****. This creates a risk for efficient investment as parties will be reluctant to invest if they may continue to be subject to a charge even though they no longer benefit from the investment. This could adversely affect competition and does not take into account new entry.*
>
> *Although allocating FTRs to parties subject to the charge may mitigate the adverse impacts of such a fixed charge to some degree, this would not address situations such as a major beneficiary exiting the market. Although the charge could be recalculated if such an event occurred,* ***this would inevitably be subject to considerable dispute, threatening the durability of the approach****. By contrast, the SPD method does not suffer from these problems.'* [our emphasis; internal footnote removed]

The contention that BB charging could reduce disputes is not compelling.

Of course, as soon as one moves away from a pure 'lock-in' approach and decides to revisit periodically the benefits estimates, a raft of other problems arises. Most notably, this creates incentives for parties to change their behaviour in inefficient ways prior to those 'resets' so as to reduce their future charges. It is those incentives that prompted, in part, the decisions to abandon several previous approaches. This

229 As we explain in section 5.2.4, there are some cases in which the BB charges applied to 'high-value' investments might be changed. However, the Authority has explained that it expects such occasions would be 'rare' under is proposed methodology. *See:* Third Issues Paper, p.144.

230 Electricity Authority, *Transmission Pricing Methodology: issues and proposal, Consultation Paper,* 10 October 2012, p.104.

illustrates why it would be difficult to implement *any* BB charging approach that would not cause *more* disputes. In our opinion, the contention that BB charging could somehow reduce disputes is not compelling.

5.2.3 Other avenues for ongoing costs and distortions

The potential for inefficient distortions and productive inefficiency to arise from additional administrative costs would extend beyond the basic design of the BB and residual charges. There are several other more specific ways that the proposed methodology could give rise to additional costs and disruptions – to Transpower in particular. First, the methodology would apply to *all* new HVDC and interconnection investments, i.e.:

- the threshold for the application of the 'standard' methodology is proposed to be $20m[231] which, although higher than the $5m proposed last time, would still encompass a large number of future investments; and
- although investments below $20m would only require the application of a 'simplified' methodology, Transpower would still need to come up with those approaches which, inevitably, would create controversy.[232]

Many things could disrupt Transpower's planning processes, or cause charges to be revisited.

The upshot of this approach is that, over time, transmission customers' charges would become more and more complex. For example, a transmission bill would not be just three numbers, i.e., a connection charge, a BB charge and residual charge. Rather, it could instead be a connection charge, a residual charge and then a long list of investments for which BB charges had been applied (perhaps twenty – maybe even fifty). Suffice it to say that this would increase substantially the ongoing costs to Transpower of administering the TPM.

Second, Transpower would have to 'provide a process' for applying BB charges to large consumers or generators who 'enter' or expand significantly (e.g., open new plant) after an investment has been made. No meaningful guidance has been provided as to how to do so, without risking distortions. In our opinion, it is highly unlikely that any such methodology exists, i.e., inefficiency is unavoidable. There would also be 'trigger' mechanisms for the BB and residual charges to be revisited in certain circumstances, for example:

- Transpower must adjust future annual BB charges if there has been, or will be, a material change in: the WACC, opex attributable to the BB investment, the remaining life of the investment or any other costs attributable to the investment – however, the draft guideline does not define 'material change';[233]
- Transpower may review the allocations of high-value investments (i.e., >$20m) if there has been, or if it expected there to be, a 'substantial and sustained change

[231] This is the threshold above which an investment is deemed 'major capex' (rather than 'base capex') under the Commission's capital expenditure input methodology.

[232] The Authority has endeavoured to provide some pragmatic suggestions for potential approaches, *see:* Third Issues Paper, p.134.

[233] Proposed TPM guidelines, clause 17.

in grid use' – the proposed TPM guideline states that a method must be derived for determining when this has occurred;[234] and

- Transpower may reassign BB charges to the residual charge when, for example, a grid investment turns out to be a 'white elephant'[235] – the proposed TPM guidelines require Transpower to determine a method for assessing a revised investment value in these circumstances.[236]

The triggers would allow adaptability – but that would come at a cost.

The 'material change', 'reassignment' and 'substantial and sustained change in grid use' triggers could be quite useful, in theory. Specifically, they might make the methodology more adaptable, over time. But that adaptability would come at a significant cost. For example, as we noted above, Transpower would need to derive methods for determining when – and how – these triggers should be activated. That would inevitably be a costly and controversial exercise that would lead to further disputes, given the potential importance of those mechanisms.

The triggers would not apply to all investments. The 'substantial and sustained change in grid use' criterion would apply only to 'high-value' investments. The allocations of investments with an initial value less than $20m could not be adjusted even if their usage had changed considerably. Similarly, 'reassignments' would not be available for investments with an initial value below $5m. Those allocations would also be set in stone. As the case study in Box 5.2 highlights, this has the potential to create some anomalous outcomes (see also footnotes 234 and 236).

Box 5.2: Potential closure of Tiwai Point smelter

The aluminium smelter at Tiwai Point currently has 622MW contracted at below-market prices until potentially 2030 (if it does not exit beforehand). It accounts for ~12-14% of total annual national electricity consumption and ~1/3 of South Island demand. If the smelter exits the market, this would have a profound impact on all aspects of the electricity supply chain. The principal effects on the transmission network would be:

- parts of the transmission grid would become highly congested, as power that typically flowed to the smelter suddenly 'switched direction' – this would be likely to necessitate some new investment; whereas

234 Proposed TPM guidelines, clause 26(c). It is also worth noting briefly here that this trigger mechanism can only be applied to high-value investments. This has the potential to lead to anomalous outcomes. For example, the Authority has suggested that one way of applying the 'simple method' would be to allocate the charges for a low-value investment between load and generation based on the allocation for a related high-value investment (*see:* Third Issues Paper, p.134). Yet, if the BB charges for the high-value investment in question were changed subsequently (e.g., because of a substantial change in grid use), the *related* prices for the low-value investment would stay the same. In our view, that seems counterintuitive.

235 Namely, a scenario in which customers make significantly less use of an investment than was anticipated initially by Transpower.

236 Proposed TPM guidelines, clause 36. Note that, here again, there is the potential for anomalous outcomes, since this process can only be undertaken for investments with initial values of $5m or more for which the 'simple' allocation method would have been applied. There is consequently the potential for the same counterintuitive scenario described in footnote 234 to occur. Namely, the BB charges for a high-value investment might change subsequently (e.g., through reassignment), yet the prices for related investments below the $5m threshold would not.

- other parts of the transmission grid would be likely to experience dramatic drop-offs in utilisation – particularly if the load centre they are servicing is, in effect, no longer there following the smelter's departure.

The triggers would not apply to all types of investment, which may create anomalies.

This is likely to lead to many potential instances of 'substantial and sustained changes in grid use' (clause 26(c) of the proposed new TPM guidelines) and candidates for 'reassignment' (clause 36). It would be a daunting undertaking for Transpower to recalculate and recalibrate the various benefits assessments to better-reflect the significantly different circumstances. Moreover, it would be limited in what it could do in those exercises.

Specifically, as we noted above, there are restrictions placed on the types of investments that can be reallocated. If customers were paying for investments that were barely being used following the smelter's exit, but their initial values were below $5m, Transpower would not be able to alter those charges. Similarly, the 'significant and sustained change of grid use' criterion could not be triggered for any investments with initial values less than $20m.

If the smelter was to exit and this proposed TPM was in place, there might consequently be large numbers of customers paying charges that no longer bore much resemblance to the benefits that they were deriving from wide arrays of assets. However, because of the restrictions in the proposed TPM guidelines, Transpower would not be in a position to change those charges.

Despite these restrictions, the existence of the triggers would be expected to compound the lobbying described in section 5.2.2. Specifically, parties would not only dispute Transpower's initial allocations of BB charges, they might also – depending upon how the criteria are fashioned – lobby continually for those triggers to be activated so that their charges could be reduced. They may even have strong incentives to alter their behaviour in inefficient ways to give rise to such adjustments, i.e., to breach the thresholds.

5.2.4 The proposal would not be unambiguously fairer

Throughout the consultation process, much has been made of the fact that there are currently customers – often in the South Island – who are paying for recent major investments that are being used to deliver services largely to other customers – often in the North Island. Similarly, South Island generators have long argued that they are not the only parties that benefit from the HVDC link. In both cases the negatively affected parties have claimed that these aspects of the TPM are not fair and have, at various times, lobbied for them to be changed.

It is unclear whether the BB charge would yield a more equitable cost allocation, since 'fairness' is subjective.

The Authority has pointed out – as have previous Axiom reports – that 'fairer' charges have the potential to be less contentious and more durable. The trouble, of course, is that unlike efficiency – which is an objective, measurable standard – equity is inherently subjective. What might seem fair to one party might appear unfair to another. It can also be affected by a variety of intertemporal considerations. It is therefore seldom possible to say with certitude whether a proposed pricing reform is 'fair', once broader considerations are put into the mix.

The current proposed reform is no exception. For example, the Authority has claimed that its proposed allocation is 'fair' because it reflects the outcome that would arise in a workably competitive market, i.e., it refers repeatedly to the slogan: "you pay for what you get".[237] However, this analysis is overly simplistic. Under the proposed approach, customers would be forced to pay prices based on a highly imperfect estimate of the benefits that they might receive over a series of uncertain scenarios over thirty to fifty years, and those charges might never change. They would also face a residual charge that includes costs for things that they do *not* get.

The Authority's proposed approach bears no resemblance to a competitive market outcome.

We are comfortable stating categorically that there is no competitive market in the world in which prices are set in this way. In competitive markets, prices are determined by the interaction of supply and demand.[238] Consumers will demand a product – voluntarily – when the private benefit they derive from consuming it exceeds the price that must be paid, taking into account the other consumption opportunities.[239] Firms may also engage in various price discrimination practices, setting different prices for different customers based on perceived differences in willingness to pay.

The most crucial thing to note is that the concept of 'beneficiary pays' is subsumed into the market resource allocation process. The value a customer receives from a good or service sets the price above which she cannot be charged. If a firm overestimates the benefits that customers will derive from its products and, therefore, the prices they are willing to pay, it will lose custom. And if a firm sought to 'lock-in' its prices for 50 years (which would be highly unusual) and got them wrong, it would almost certainly go out of business.

Conversely, under the Authority's proposed approach, if the BB charges turned out to be 'wrong' it is *customers* that would lose. That is the *opposite* of what happens in a competitive market. The Authority's repeated assertion that its BB charge is 'market-like' is therefore inaccurate. Moreover, it is far from clear that locking-in prices in this manner would be 'fairer', given all of the aforementioned uncertainties that would surround the estimation of benefits. Indeed, if all of the assumptions underpinning a BB price turned out to be wrong – which they could – the resulting charges could be argued to be extremely *unfair*, based on the Authority's own logic.

It is also unclear why it would be fair to subject some existing investments to BB charges, but not others. The Authority has endeavoured to explain why, in its view, it is important to reallocate the costs of existing investments. But why just seven?[240] This makes no sense. There is undoubtedly an ostensible appeal to the argument

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237 Third Issues Paper, p.18.

238 When substantial market power exists, the price at which firms are prepared to offer their output is determined not only by their costs of production, but also by the willingness of its customers to keep buying the product as it gets more expensive.

239 And firms will supply a product when the revenue earned from supplying it exceeds the costs that must be incurred to produce it, including a return on capital, taking into account the other production opportunities that may be more profitable.

240 The Proposed TPM guidelines do countenance Transpower extending the application of BB charges to additional pre-2019 investments, but they do not mandate it.

that 'Christchurch consumers should not have to pay for upcoming upgrades, plus a share of the recent investments that have benefitted Aucklanders.' But, like most arguments predicated on notions of 'fairness', it cuts both ways.

There is no equitable basis for reallocating the costs of some existing investments but not others.

For example, it is equally valid to ask whether customers in Auckland and Northland should be required to pay for a relatively arbitrary selection of recent investments, as well as a share of older investments that may have benefitted predominantly customers in *other* parts of the country. North Island customers might also point to several other anomalous outcomes. For example:

- in 2013, NZAS received $30m in government subsidies – collected, in part, from North Island-based taxpayers – to reduce its operating costs and prevent it from leaving the market;
- it has been estimated that NZAS's total transmission bill would go down by around $11.3m p.a. if the proposal was implemented, whereas, the total paid by the four northern most distributors would go up by $10.6m p.a.;[241] and
- customers in Auckland and Northland might justifiably question whether it would be fair to ask them to, in effect, fund yet another price cut for the smelter, given that they have done so indirectly already through their tax dollars.

For those reasons, in our opinion, it is also unclear whether it would be 'fair' to reallocate the past costs of existing investments – and there would seem to be no equitable basis for limiting any such exercise to a handful of recent investments. More generally, it might also be said to be 'unfair' to change the way in which sunk costs are allocated so soon after a major investment programme. Rightly or wrongly, this might be viewed by some as it 'shifting the goal posts' and it could even undermine the confidence that some participants have in future investment approval processes – and transmission pricing frameworks.

What is fair can almost never be established with certainty – and this case is no exception.

Ultimately, what is 'fair' can almost never be established with certainty or with universal agreement. It is for this reason that objective efficiency considerations should, rightly, take precedence in regulatory decision making. In our opinion, the proposal would compromise objective measures of efficiency for the reasons set out hitherto, and it cannot be said definitively to be 'more equitable' than either the status quo or more conventional alternatives, such as forward-looking LRMC-based approaches. Accordingly, we do not consider that there would be any material increase in 'durability' arising from perceived improvements in 'fairness'.

5.3 Summary

The Authority contends that its proposed approach would give rise to a more efficient, fairer and, consequently, more durable allocation of sunk costs. In our view, that is unlikely to be the case. There is nothing that the proposal could do to discourage inefficient load shedding that more orthodox alternatives – such as LRMC-based prices with a residual charge – could not do at least as well or better. However, the Authority's proposal could *compromise* allocative efficiency in a

[241] These are Vector ($7.1m); Counties Power ($0.1m); Northpower ($2.2m); and Top Energy ($1.2m).

variety of ways – especially in the future when grid constraints start to re-emerge with greater regularity.

The proposed approach would also give rise to significant additional costs arising from the uncertainties and disputes that would result inevitably from its introduction, i.e., productive inefficiency. We also do not agree that the proposal would promote competitive market outcomes or greater fairness. The approach is not 'market-like' in any meaningful sense and it is far from clear that it would be more equitable than the status quo. For example, reallocating the costs of just a handful of existing investments would seem to be both inequitable and illogical. Figure 5.1 summarises our key conclusions.

Figure 5.1: Potential effects on static efficiency and administrative costs

Reallocating sunk costs via the proposed methodology would not improve allocative efficiency

- Although inefficient load shedding would cease in the near-term if the proposal was implemented, this would be due to the removal of the RCPD charge, not the introduction of the proposed methodology – there are many other ways to achieve that outcome, e.g., via LRMC-based pricing
- There were static inefficiencies arising from the HAMI-based parameter on the HVDC charge, but these have diminished significantly following the phased introduction of the SIMI-based parameter
- The proposal to apply DHC-based charges to existing assets earmarked for BB charges is unnecessary and would result in an inefficient time profile of prices

Implementing the proposed approach could give rise to additional costs, i.e., reduce productive efficiency

- There would be significant additional costs associated with estimating private benefits – and these would increase with the complexity of the methodology
- More complex allocation methodologies – such as the vSPD approach would be likely to give rise to a significant increase in lobbying and disputation
- Transpower would need to determine a way of estimating reliability and resilience benefits, e.g., the vSPD approach does not capture these important benefits
- There would be more scope for ongoing disruptions through the design and application of the various 'trigger mechanisms', e.g., reassignments.
- The proposed approach would not be 'fairer' than the status quo and would therefore not result in fewer disruptions.

Accordingly, like its predecessors, we do not consider that the latest proposal has a robust economic foundation. There is no reason to think that it would provide more efficient forward-looking price signals or result in a superior allocation of sunk costs. Rather, the proposed approach is more likely to compromise significantly both static and dynamic efficiency. Furthermore, the CBA does not in any way diminish this conclusion – quite the contrary; if anything, it serves simply to reinforce that finding.

6. Assessment of the cost benefit analysis

The new CBA cannot provide any meaningful insight into the merits of the Authority's proposal.

The CBA represents the principal 'new' piece of analysis in the consultation package. As we have seen already, the broad scheme of the proposal itself is largely unchanged from the methodology the Authority was suggesting in December 2016. This new CBA is therefore the Authority's second attempt to supply an empirical justification for its proposal after its first – the OGW CBA – was revealed to be irredeemably defective. Broadly speaking, the Authority has used its CBA to compare its proposal (and one alternative) to the current TPM.[242] Based on that analysis, it concludes that:[243]

> *'…the proposal would deliver substantial benefits to New Zealand's economy and that the central estimate of **$2.7 billion** [resulting from the CBA], within the range of $0.2 billion and $6.4 billion, is a realistic estimate of net benefits.'* [our emphasis]

In our opinion, this latest CBA does not – and cannot – provide any meaningful insight into the merits of the Authority's proposal. There is no basis for the Authority to conclude that its proposal would yield a net benefit *at all*, much less the $2.7b sum it has suggested. The sheer number of shortcomings in the modelling has meant that, in the interests of parsimony, we have focussed in this section on only the most critical errors. Our all-inclusive assessment of almost[244] every element of the CBA – together with all its problems – is provided in Appendices A and B.

6.1 Key findings

The CBA is unduly narrow and exhibits many of the same flaws as its predecessor.

The CBA is remarkably narrow. For example, the Authority does not seek to quantify the costs and benefits of introducing an LRMC option, despite the fact that its own staff recommended such an analysis.[245] This is hard to understand, given the ample time there has been to undertake a comprehensive assessment (more than two years), and the fact that LRMC pricing options have garnered significant stakeholder support during submissions.[246] This immediately introduces bias into the CBA, since the fewer alternatives the Authority looks at, the more likely it is that the methodology it is proposing will appear to be the most beneficial.

242 That is arguably not the correct approach. The Authority is reviewing the TPM *guidelines*. There are many different ways in which Transpower might change the current pricing methodology *within* the existing guidelines, e.g., by increasing the number of periods over which contributions to RCPD are measured. In other words, the CBA immediately gets off on the wrong foot.

243 Third Issues Paper, p.55. Note that values are in NPV terms and 2018 dollars.

244 As noted in section B.1.7, the CBA modelling involved a significant amount of material and complexity. Although we have reviewed much of this (as reflected in the appendices), we have not – and we doubt any stakeholder has – been able to effectively review *all* of it.

245 Electricity Authority, *Nodal pricing and LRMC charging*, p.2.

246 It is also inconsistent with the Authority's Decision-Making and Economic Framework (DMEF) which, as it has acknowledged previously, 'ranks' LRMC-based approaches *higher* on the list of options than BB charging methodologies. We continue to think that the DMEF is not a useful tool but, even so, it is curious that it has been cast aside so swiftly in this instance.

Setting aside those more general problems, specific elements of the modelling itself give rise to even graver concerns. The previous CBA performed by Oakley Greenwood was criticised roundly and heavily for many reasons. For example, it abstracted away from the methodology that had *actually been* proposed, failed to represent the way the electricity market actually worked and how actors within it made decisions, and contained a litany of rudimentary modelling errors. [247] Regrettably, this latest CBA exhibits shortcomings that are eerily similar.

As we explain in more detail in the following sections, the CBA contains some obvious and, in many cases, very serious mistakes. Many of these errors are sufficiently serious in their own right to cast considerable doubt over the efficacy of the estimated net benefit. In culmination, they serve to undermine completely the reliability of that result. In our opinion, the new CBA is just as flawed – if not more so – than its ignominious predecessor. For example, the $2.7b net benefit estimate:[248]

The errors in the CBA undermine completely the reliability of the results.

- reflects the outcomes of modelling that does not depict the methodology that has actually been proposed; for example:
  - the grid use modelling (which produces 96% of the estimated net benefit) does not include the implicit forward-looking 'shadow' price signals that the Authority says would be supplied by the proposed BB charges; and
  - the 'top-down modelling' *does* include forward-looking price signals but, they are *wrong*, i.e., the model mistakenly assumes that consumers would face price signals that reflected a rudimentary measure of the LRMC of transmission, which is incorrect;[249]
- could be reproduced using virtually any methodology comprised solely of fixed charges, i.e., those fixed charges would not need to be based on estimated benefits – any number of alternatives could be used;
- includes $2.3b in wealth transfers that are neither benefits to New Zealand's economy nor improvements to the overall efficiency of the electricity industry – these are simply payments from one group of consumers (generators) to another (final consumers), i.e., this is not 'new wealth';[250]
- ignores the significant cost of additional investment in generation ($1.9b) and distribution networks (conservatively ~$27–$81m) that would be needed to support the noticeable increase in peak demand that the Authority has forecast to occur if its proposal was adopted;

247 *See:* Axiom Report on Second Issues Paper, pp.51-61 and Appendix B.

248 Throughout this section, financial values are reported in NPV terms and 2018 dollars, unless stated otherwise.

249 This is exactly the same mistake that Oakley Greenwood made in its CBA. It assumed – wrongly – that shadow prices would reflect a measure of the regional LRMC of transmission. However, as we explained previously, BB charges *would not be cost-reflective*. The BB shadow price signals that individual customers would face would not be equal to LRMC.

250 An alternative to removing the wealth transfer from the net benefit (to improve accuracy) would be to recognise the reduced revenue earned by generators as a cost in the CBA, of $3.9b.

- ignores the cost of additional carbon emissions that would be likely to be produced if peak demand increased as forecast (since gas fired peaking plants are used to meet that incremental demand);
- was calculated using assumptions and investment decision rules that do not reflect reality, including that investors would not consider future returns when deciding whether to invest in grid-connected generation, which produces modelled outcomes that defy common sense;
- relies on modelled outcomes that do not appear to reflect reality either, including that an increase in peak demand would lead to a significant price reduction and that generation investment would continue even when wholesale revenues declined drastically;
- includes estimated benefits that are highly unreliable and based on arbitrary assumptions, such as those relating to greater scrutiny of Transpower's investment proposals ($77m) and increased certainty for investors ($26m);[251] and
- includes several calculation errors and statistically unreliable inputs that further undermine confidence in the analysis and conclusions.

Once these and other shortcomings are factored in, it is not possible to conclude that the Authority's proposal would deliver a net benefit to New Zealand's economy or improve the overall efficiency of the electricity industry.[252] For example, if the problems described in just the third and fourth bullets were addressed, then the estimated net benefit of the Authority's proposal would drop to **-$1.5b**, i.e., it would become a substantial **net cost**.[253] In the remainder of this section we describe briefly the CBA methodology and explore some of these key problems.

6.2 Modelling approach and results

Three estimation tools are used to estimate costs and benefits.

The Authority adopts as its 'status quo' the current TPM. The costs and benefits of its proposed approach (and of the alternative option) are estimated relative to that current methodology. Three estimation tools (or 'assessment methodologies') are employed to estimate those costs and benefits. These are:

[251] The Authority here has made the same mistakes that it made in its first CBA. In each case assumptions have been made about the value of key inputs based on nothing more than its subjective assessment of the *answer* that the analysis should be producing. In other words, benefits have been *assumed* rather than *estimated*.

[252] The Authority interprets its statutory objective to mean that 'the TPM should promote overall efficiency of the electricity industry for the long-term benefit of electricity consumers'. *See:* Third Issues Paper, p.188.

[253] This figure is obtained by taking the $2.7b net benefit estimate and subtracting $2.3b then $1.9b. To be clear, we are not suggesting that this represents a sound estimate of the likely net benefit – or cost in this case – from implementing the Authority's proposal. It is simply the revised result that one obtains when the two issues are addressed. Even with those corrections, the CBA remains unfit for its intended purpose on account of the many other shortcomings identified in this report. In other words, the CBA cannot be used to provide *any* reliable gauge of the overall quantitative impact of the Authority's proposal.

- **A grid use model** – this is used to analyse how consumption, generation, prices and investment change in response to different TPMs and demand or investment scenarios. The model relies on:
  – assumed decision rules (e.g., when to invest in generation or batteries) and economic relationships (e.g., demand);
  – parameter inputs (e.g., elasticities) estimated by fitting econometric models to historical data; and
  – data sourced from Statistics New Zealand and the Authority's own Electricity Market Information database.
- **Top-down analysis** – this is used to assess how investment efficiency, scrutiny and certainty may change in response to different TPMs. This analysis relied on:
  – Monte Carlo simulation of assumed distributions, based largely on the Authority's judgement;
  – assumed economic relationships and input parameters (e.g., changes in the number of uncertainty events if the TPM proposal was adopted); and
  – historical and forecast peak demand, expenditure and generation capacity data.
- **Bottom-up build of costs** – this is used to estimate the costs for developing, implementing and operating a new TPM. It relied primarily on Transpower's 2016 estimate of applying a complex TPM and the Authority's judgement.

These estimation tools are used to derive costs and benefits for a variety of categories. Table 6.1 below summarises this taxonomy and identifies the estimation technique that was employed in each case. The Authority highlights in the Issues Paper that these categories are non-exhaustive.[254]

Table 6.1: Summary of costs and benefits

Category	Description	Estimation approach	Estimation tool
		Benefits	
More efficient grid use	Increased use of electricity at times when it is valued most highly by consumers	Present value of change in consumer surplus estimated by comparing projected changes in prices and usage *plus* the estimated increase in interconnection charges paid by consumers	Grid use model

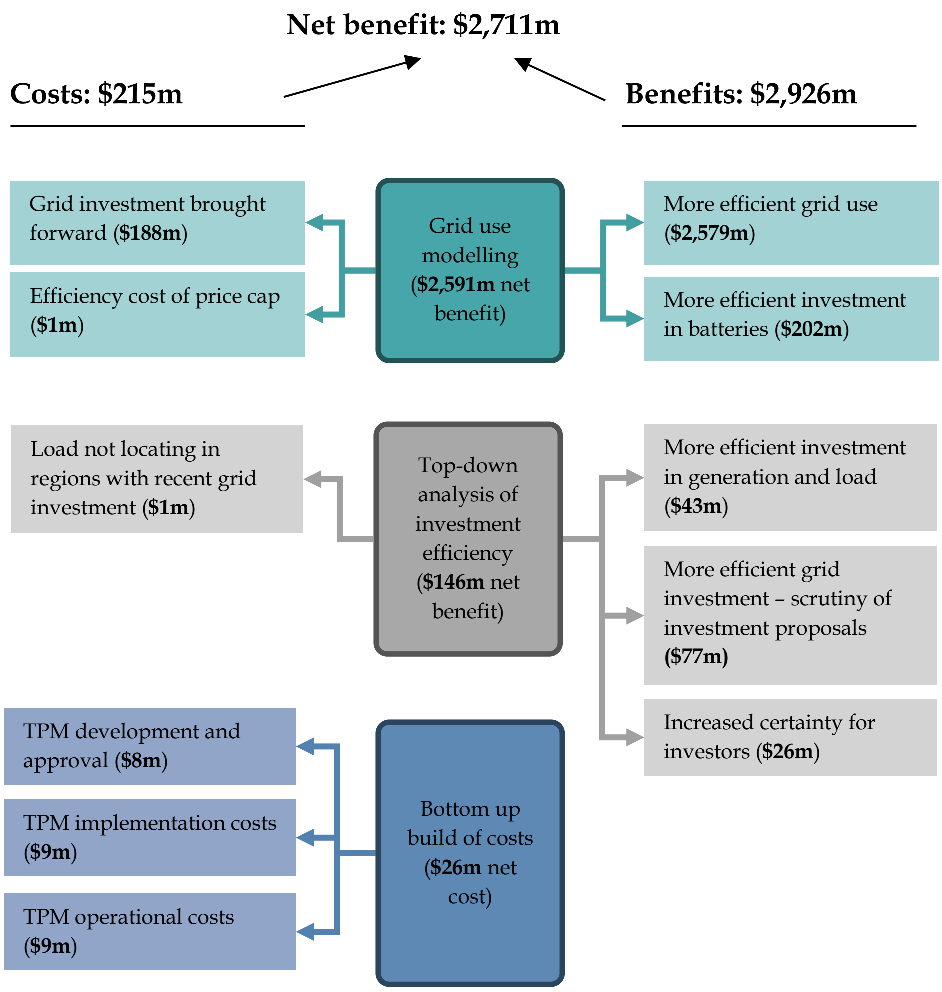
254 Costs and benefits that were *not* reflected in the CBA include the avoided costs of undergrounding (which, as we explained earlier in this report, is likely to be zero), avoided inefficient investment in emerging technology by mass-market consumers, any additional cost of distribution or generation investment (which is an enormous omission) and effects on industries, markets or policy objectives outside of the electricity industry, including any carbon or other environmental effects.

Category	Description	Estimation approach	Estimation tool
More efficient investment in DER	Reductions in investment in DER (grid-scale) batteries for the main purpose of avoiding transmission charges	Present value of projected avoided investment in batteries	Grid use model
More efficient investment by generators and large consumers	More efficient investment by generators and large consumers (since they would supposedly account for the costs of grid upgrades when making decisions) leading to reduced transmission investment	Present value of estimated reduction in total transmission investment	Top-down analysis / Monte Carlo simulation
More efficient grid investment – scrutiny of investment proposals	More efficient grid investment by Transpower due to greater scrutiny of its expenditure proposals from interested consumers and less lobbying for inefficient investments	Present value of expected reduction in grid investment caused by additional scrutiny estimated by multiplying projected capital expenditure by either 4%, 2%, or 1%, depending on expenditure category	Top-down analysis
Increased certainty for investors	Increased certainty reduces the required return on investment	Present value of change in total surplus estimated by simulating the impact on supply, demand and prices of reducing the frequency of 'uncertainty' events (from one every ten years to one every eleven years)	Top-down analysis / Monte Carlo simulation
Costs			
TPM development and approval costs	Costs such as policy analysis, modelling and legal fees	Detailed build-up of the employee / contractor time and cost needed based on Transpower's 2016 estimate of its TPM development costs, plus expected costs of legal challenge	Bottom up build of costs
TPM implementation costs	Costs of computer hardware and software, development and testing and user training	Detailed build-up of the employee/contractor time and cost needed based on Transpower's 2016 estimate of its TPM implementation costs, plus expected costs of legal challenge	Bottom up build of costs
TPM operational costs	Costs of data gathering and management, invoicing and customer liaison	Detailed build-up of the employee / contractor time and cost needed based on Transpower's 2016 estimate of its TPM operational costs	Bottom up build of costs
Grid investment brought forward	Cost of transmission investment occurring earlier to cater for increases in peak demand	Present value of the projected increase in direct grid investment caused by the increase in peak demand	Grid use model

Category	Description	Estimation approach	Estimation tool
Load not locating in regions with recent grid investment	Distortion from large energy-intensive consumers avoiding investing in a region that has a BB charge	Present value of estimated increase in total transmission investment caused by large consumers not relocating to where there is more transmission capacity	Top-down analysis / Monte Carlo simulation
Efficiency cost of price cap	Suppressed demand from customers with uncapped charges	Present value of change in consumer surplus and revenue recovered from load estimated by comparing projected changes in prices and usage from applying the price cap	Grid use model

Figure 6.1 summarises the benefits and costs that the Authority estimates would arise from its proposed methodology (under the 'central case'). The lion's share of the net benefit stems from the grid use modelling, which we consider below.

Figure 6.1: Summary of CBA approach (central case)



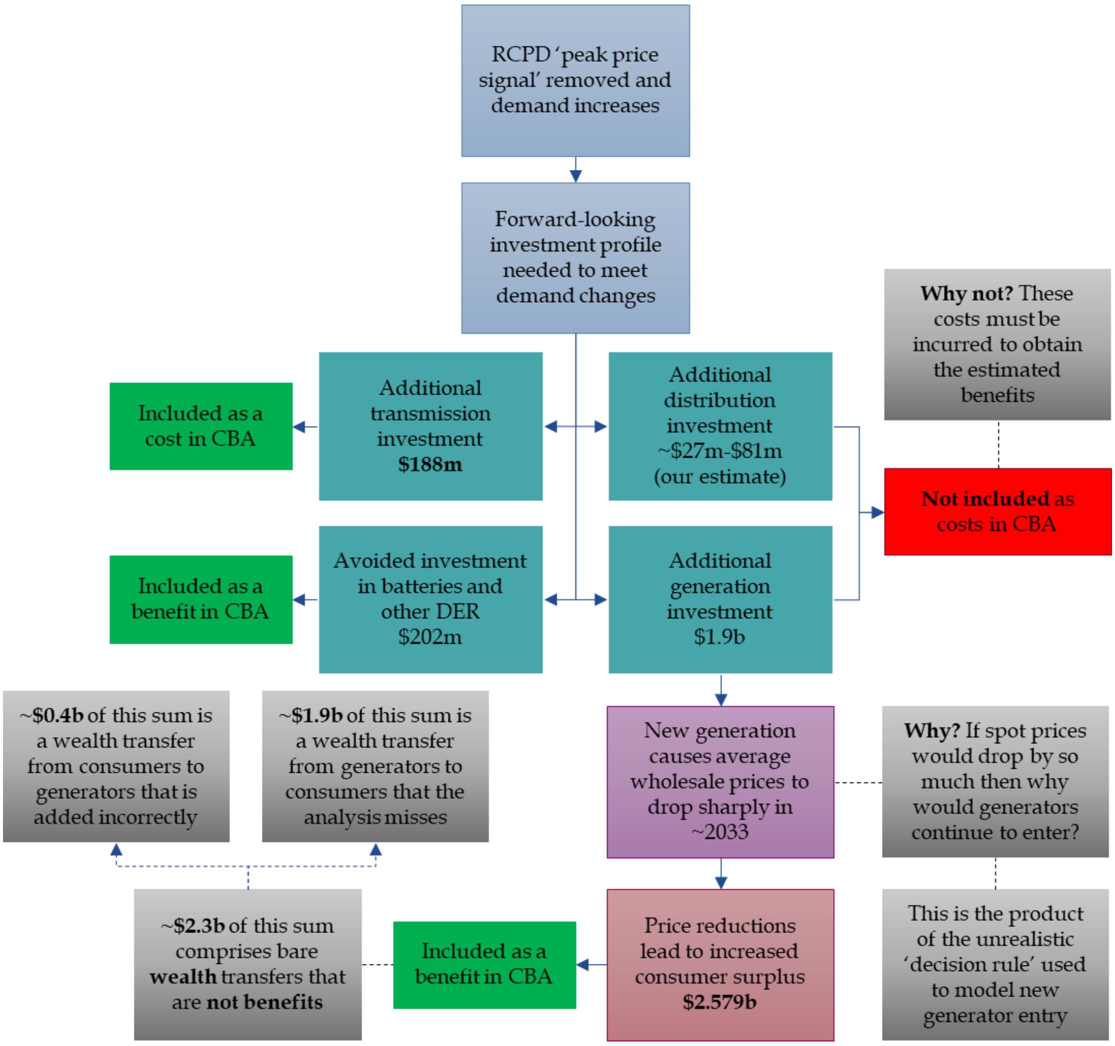
The vast majority – 96% - of the estimated net benefits are produced by the grid use modelling.

6.3 Grid use modelling

The vast majority (96%) of the estimated benefits from the Authority's proposal are produced from the grid use model. Nearly all (99.5%) of those benefits are said to arise from the 'more efficient grid use' that is forecast to result from the removal of the RCPD peak price signal. However, those purported benefits have no sound basis. As Figure 6.2 summarises, the modelling exhibits a cascading series of methodological errors – many of which are extremely serious – that culminate to produce a benefit estimate that is overstated by **more than $4b**.

Figure 6.2: The mechanics of the grid use model

The grid use modelling exhibits a cascading series of errors – many of which are extremely serious.



The model ignores nearly $2b of additional investment costs.

The model assumes that the removal of the peak price signal would lead to an increase in demand. In time, this leads to new investment in transmission ($188m) and generation ($1.9b), yet only the former is included as a cost in the CBA. The additional distribution investment that would be needed to meet that increased demand (which we estimate, conservatively, to be ~$27m-$81m) is also ignored. However, $202m in avoided investment on batteries *is* included as a benefit. This asymmetric treatment of costs inflates the net benefit estimate by **nearly $2b**.

Despite the model disregarding the cost of the additional $1.9b in forecast new generation, it includes the benefits that are said to flow from it. Specifically, that influx of new generation – that begins in the mid-2030s – is assumed to drive down wholesale prices, making electricity cheaper for final customers. The Authority estimates that those customers would be better-off to the tune of $2.6b as a result of those price reductions, which accounts for 96% of the overall net benefit estimate. However, there are two problems with this supposed sequence of events.

Much, if not most, of the new generation predicted by the model would not happen in the real world.

First, as a matter of basic economics, it is not at all clear why an enduring increase in demand in peak periods would lead to a price *reduction*. Why would the supply-side response outweigh the demand-side effect – and by such a considerable margin? This counterintuitive outcome is the result of the 'decision rule' that the Authority has applied to model generator entry. As we shall see, that rule assumes that generators would invest without giving any thought to the potential consequences for future spot prices. Afflicted with this myopia, the generators in the model consequently invest billions of dollars in new plant – a large proportion of which would almost certainly not produce a reasonable economic return.

It is this 'lemming-like' behaviour that is driving the peculiar reduction in spot prices that emerges around 2033. Of course, this would happen in a 'real world' market. Generators would factor future spot price movements into their decision making and, in many cases, opt *not* to invest. The wave of generation investment the model is predicting would therefore not transpire or, at least, not on nearly the same scale. The Authority then compounds this problem with a second error. Namely:

- it measures the benefits that final customers would receive from that (unrealistic) price reduction (i.e., the increase in 'final consumer's surplus'); *but*
- it neglects to net-off the *reduction* in benefits that *generators* would experience as a result of the price drop (i.e., the drop in 'generator surplus'[255]); *and*
- it then compounds this error by adding $368m to the net benefit to account for a transfer from consumers to generators, which is *entirely unnecessary*.[256]

Almost all of the increase in consumer surplus resulting from the forecast (unrealistic) price drop is a wealth transfer, i.e., not a benefit.

By definition, if someone is suddenly *paying* a lower price, someone else will be *receiving* that lower price. Here, final customers *pay less* for their electricity and generators are *paid less.* By our estimation, around **$2.3b** or **88%** of the (illusory) $2.6b benefits estimate – is a bare transfer of wealth from one set of customers (generators) to another (final customers).[257] It is not a benefit at all. The Authority has said that it does not take wealth transfers into account when making decisions but, consciously or otherwise, that is exactly what it has done.

255 Note that 'generator surplus' is not 'producer surplus' in the traditional sense, since generators are also consumers of transmission services.

256 The Authority does so because it thinks that this sum has been included as a cost elsewhere in the CBA and that an offsetting adjustment to 'benefits' is needed so that it 'nets out' to zero. However, the transfer *is not* treated as a cost anywhere else. Therefore, the adjustment is not appropriate.

257 This includes both a wealth transfer from generators to final consumers ($1.9b) and a wealth transfer from consumers to generators ($0.4b) that is added back (although incorrectly). With the latter, implicitly, the Authority is assuming that the wealth transfer must already be included as a cost in the CBA somewhere else. That being the case, it adds it back as a benefit so that it will 'net out' to zero. However, the wealth transfer *is not* treated as a cost anywhere in the CBA, so this erroneous adjustment inadvertently inflates the net benefit estimate by a further $0.4b.

Addressing the two most basic errors in the grid use model (adding the $1.9b in additional generation costs and removing the $2.3b in wealth transfers) reduces the overall net benefit estimate by **over $4b** to **-$1.5b**, i.e., to a **net cost**.[258] We explore these problems with the grid use model in more detail in the following sections.

6.3.1 The modelling of generator entry decisions is flawed

A key driver of the net benefit estimate produced by the grid use model is the additional grid-connected generation investment that it forecasts. However, as we foreshadowed above, that investment results from the application of a decision rule that makes very little sense from an economic perspective. In fact, it causes the model to predict that generators would invest in additional generation plant that may *not be profitable,* i.e., it would potentially give rise to *inefficient* investment. The Authority describes the rule as:[259]

> *'The modelling of generation investment assumes investors will install new generation plant in a given region after short-run wholesale prices in that region exceed long-run marginal cost in any year.'*

The model assumes that generators ignore future prices when making investment decisions.

In other words, the entry 'decision rule' that is adopted (equation 25 in the Technical Paper) assumes that generators would assess the financial viability of potential investments by looking only at *past and current returns* – and for a *single year*.[260] It also assumes that new generators would dispatch *all* of their capacity at the average dispatched per MW price. That does not comport with reality and is at odds with efficient investment decision making. Like in any market, generation entry decisions are based on one principal factor: *projected future cashflows*.[261]

To that end, one of – if not the single – most important matter that a firm would consider before investing in new generation is *future* wholesale prices, net of transmission charges.[262] To be sure, past and current spot prices may be a key factor in a generator's assessment of future prices, but they cannot substitute for them. For example, if a generator anticipated that its entry – and/or entry/expansion by others – would lead to a sharp reduction in nodal prices, then it would be disinclined to invest. It would also take into account how often it expected to be dispatched – it would not simply assume full utilisation.

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258 To reiterate, we are not suggesting that this represents a sound estimate of the likely net benefit – or cost in this case – from implementing the Authority's proposal. It is simply the revised result that one obtains when the two issues are addressed. Even with those corrections, the CBA remains unfit for its intended purpose on account of the many other shortcomings identified in the remainder of this section.

259 Third Issues Paper, p.25.

260 This is confirmed by inspecting the Python code used to implement the decision rule in the grid use model.

261 *See for example:* Copeland, Weston and Shastri, 2005, *Financial Theory and Corporate Policy*, Fourth Edition, p.18, where the authors explain that 'the objective of the firm is to maximize the wealth of its shareholders…[which is] more carefully defined as the discounted value of future cash flows'.

262 Although, as we explain subsequently, the model does *not* include the *forward-looking* shadow price component of BB charges. This represents another key shortcoming, because the Authority has not modelled its own proposal.

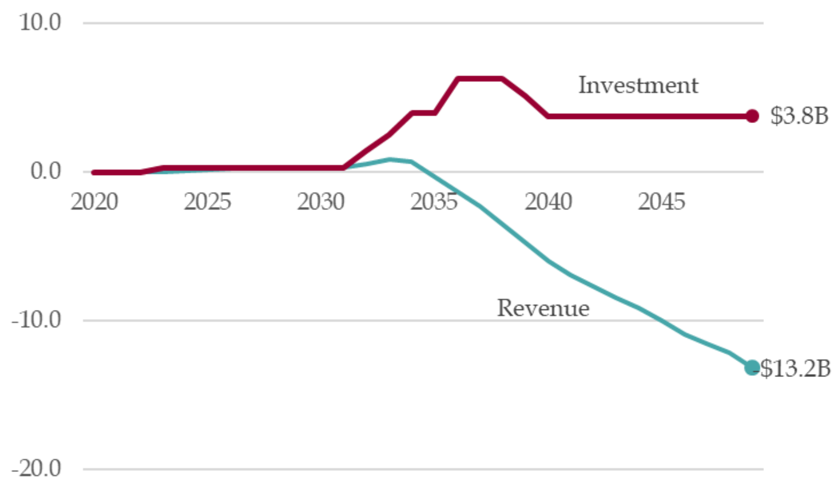
Generators are forecast to be worse off to the tune of $5.8b in NPV terms under the proposal.

To that end, the model is predicting that generation investment would increase by $3.8b over the 2020 to 2049 period, while wholesale market revenue (net of interconnection charges) would *fall* by $13.2b.[263] That is a very poor return on investment, to put it mildly. Collectively, in NPV terms, generators are forecast to be worse off to the tune of $5.8b under the proposal – with reductions in revenue accounting for $3.9b of that sum.

The Authority has suggested that the additional generation investment that occurs in its model can be presumed to be efficient, because it would be taking place in a competitive market. As we explain shortly, that proposition is nonsensical on its face (see section 6.3.4), but it is even more misguided in this context. The generators in the model are not 'investing in a competitive market' – they are investing in accordance with a decision rule (equation 25 in Technical Paper) that bears no resemblance to what would happen in the real world. Figure 6.3 illustrates.

Figure 6.3: Comparison of cumulative generator revenue and investment cost differences (proposal less status quo) ($b, $2018)[264]

The model assumes that generators would invest large sums while ignoring the impacts on prices and returns.



It is *possible* that *some* generators might be better off in the peculiar scenario that emerges from the grid use model. However, it is beyond dispute that most would be *far worse off* on average. Figure 6.3 illustrates the striking divergence between the amount that generators are assumed to invest under the grid use model and the steadily dwindling returns they receive. Put simply, the model assumes that generators would continue to happily invest very large sums while ignoring the consequential impacts upon wholesale prices and *expected* returns.

263 Both values are in total dollar terms. Note that the $1.9b in additional generation investment referred to earlier was in NPV (discounted) terms. In other words, generation investment increases by $3.8b in *total* over the 2020 to 2019 period relative to the status quo, and by $1.9b in *NPV terms*.

264 Data are sourced from the 'AOB.csv', 'RCPD.CSV' and 'generation_investment.csv' files for the 'All_major_capex' scenario. Generator revenue is calculated for a given year by multiplying the quantities for each backbone node and time period by the corresponding generator price and summing these together. A net revenue value is obtained by subtracting the interconnection charges faced by generators.

Much of the new investment driving the forecast spot price drops would not happen.

In summary, the counterintuitive generator entry decision rule has caused the Authority to conclude that the introduction of its proposal would lead to an influx of new generation that would drive down spot prices. That is almost certainly incorrect. In truth, much of the generation investment depicted in Figure 6.3 *would not occur*. Accordingly, the wholesale price reductions that are driving 96% of the Authority's net benefit estimate would not happen. And, without those price reductions, the $2.6b benefit from more efficient grid use would disappear.

6.3.2 The benefit estimate is largely a wealth transfer

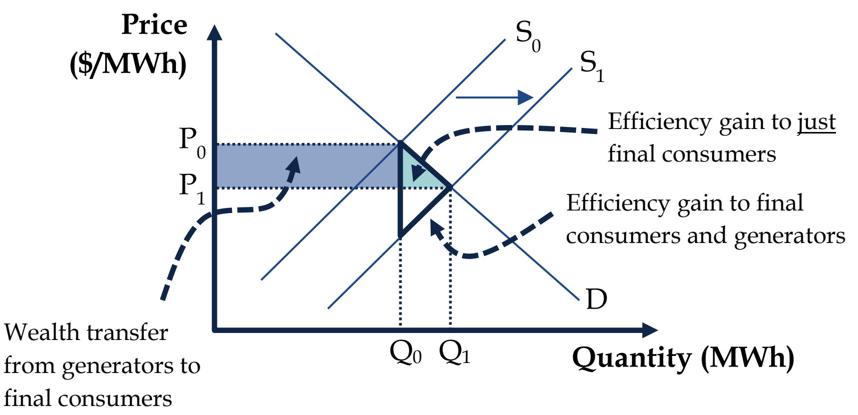
Having assumed – erroneously – that its proposal would lead to a wave of new generation and lower prices, the Authority then makes a second error. It assumes that the resulting efficiency gain from 'more efficient grid use' is equal to the benefits that *final* consumers derive from those lower prices. It is not. The Authority has inadvertently conflated changes in final consumer surplus with changes in allocative efficiency. These are *not synonymous*.

Figure 6.4 highlights this problem. The equation at the top is a simplified version of the consumer surplus calculation used by the Authority to determine its central CBA net benefit estimate (equation 10 in the Technical Paper). The chart beneath it is a stylised representation of what happens to consumer surplus when there is a movement *along* the demand curve (i.e., an increase in quantity demanded, following an outward shift of the supply curve).

Figure 6.4: Measuring consumer surplus with a shift along the demand curve

$$\Delta CS = \underbrace{-Q_0 \times (P_1 - P_0)}_{\text{Wealth transfer}} - \underbrace{0.5 \times (Q_1 - Q_0) \times (P_1 - P_0)}_{\text{Efficiency gain}}$$

Changes in consumer surplus contain both bare wealth transfers and changes in deadweight loss.



In the figure, the supply curve shifts outwards, which leads to an increase in the quantities supplied and demanded and a reduction in the market-clearing price. There are two effects from the reduced price:

- some surplus is shifted from generators to final consumers, i.e., a transfer of 'generator surplus[265]' to 'final consumer surplus' (see the blue rectangle); and
- some new consumer surplus is generated that is not taken from anyone else, i.e., a reduction in 'deadweight loss' (represented by the green triangle).[266]

Transfers do not result in any additional welfare or new wealth.

The former is a bare transfer of wealth. It arises because of the reduced prices that final consumers pay for electricity that they would have consumed anyway at the higher price. It comes entirely at the expense of generators who receive those now lower prices.[267] This does not produce any *additional welfare* that did not previously exist – it is a bare transfer of current wealth and is consequently *welfare neutral*. It is for that reason that the Authority has said it does not account for transfers in its decision making (despite doing precisely that in its CBA).

A reduction in deadweight loss creates new welfare.

In contrast, the reduction in deadweight loss (represented by the green triangle) clearly *is* an efficiency benefit. At the lower price, there is additional demand for electricity that *did not happen* at the previous, higher price. Provided that demand can be served a price that generators are willing to accept and that final consumers are willing to pay *new wealth* can be generated. In other words, it is possible to make some people better off without making others worse off.

Transfers tend to be much larger than changes in deadweight loss.

In other words, changes in consumer surplus entail both allocative efficiency improvements ('triangles') and bare wealth transfers ('rectangles'). Because triangles tend to be smaller than rectangles (at least in this context), the transfer component will often outweigh the reduction in deadweight loss – typically by a comfortable margin. Regrettably, the Authority has failed to make this basic but crucial distinction in its grid use model.

Instead, the equation the Authority has employed measures the *total change* in consumer surplus which, as we have seen, will include bare wealth transfers. By failing to differentiate between these two effects, the Authority has mistakenly included the 'wealth transfers' from generators to final consumers in its estimated net benefit. This has caused it to overstate the benefits that would flow from more efficient grid use – and to a startling degree.

In our assessment, the wealth transfer component described above accounts for around 73% or \$1.9b of the \$2.6b estimated benefit from more efficient grid use.[268] Those transfers are *not* 'gains' to the New Zealand economy. The Authority itself

[265] Note that 'generator surplus' is not 'producer surplus' in the traditional sense, since generators are also consumers of transmission services.

[266] If total welfare gains were being measured, then the entire area of the bolded dark triangle outline would be captured.

[267] In truth, that rectangle is the *net* wealth transfer. As the Authority itself recognises, the grid use model predicts some transfer of interconnection charges from generators to final consumers if its proposal is adopted, which are effectively netted out in that rectangle. This arises because the prices used to apply equation 10 include generation prices, transportation costs *and* interconnection charges, but exclude retail margins or costs.

[268] The details of this calculation – which is not straightforward – are set out in section B.1.3.

has said that it 'does not take wealth transfers into account in making decisions.'[269] It has even taken steps to remove them from analyses in some instances. For example, it *adds back* the wealth transfer from final consumers to generators related to the changes in transmission interconnection charges. The Authority describes this in the following way:[270]

The Authority has mistakenly included $1.9b in transfers from generators to final customers in its net benefit estimate.

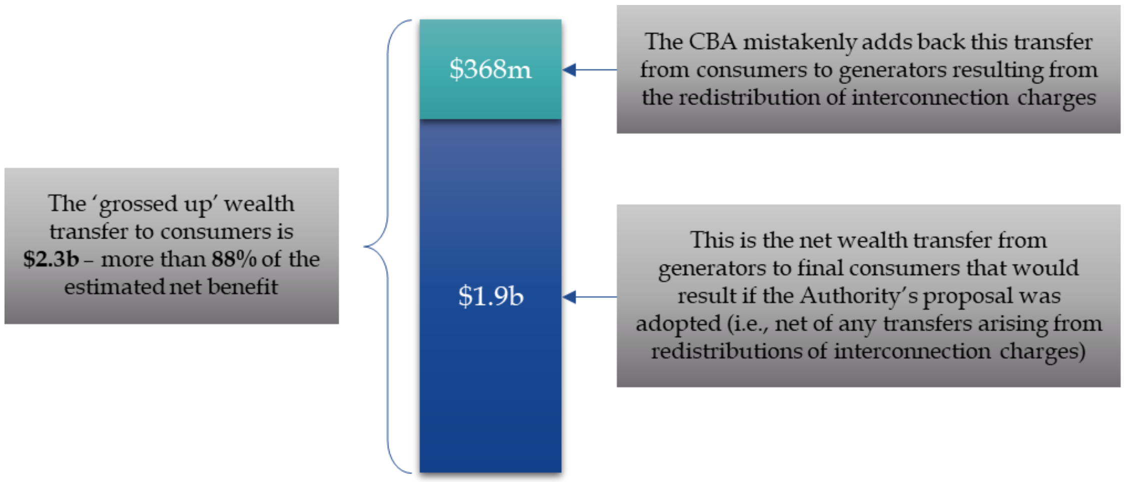
> *'Under the proposal, over the modelling period, consumers end up paying higher transmission charges and generators end up paying lower charges (compared to the status quo). So amongst other things, the proposal causes a wealth transfer from consumers to generators.'*

The Authority then compounds its error by adding needlessly another $368m to the net benefit estimate.

Unfortunately, as well-intentioned as this adjustment may have been, it is a mistake that serves to *exacerbate* the earlier error. The Authority adds $368m to the benefit estimate to reflect the interconnection changes that are transferred from generators to final consumers in the grid use model, i.e., a wealth transfer from the latter to the former. This would make sense if the $368m was included elsewhere in the CBA as a cost, i.e., adding it back in as a benefit would see it 'net out' to zero. But it is not.[271] The needless adjustment therefore serves to inflate the net benefit estimate by a further $368m. It pushes the total sum of inappropriate wealth transfers up to **$2.3b**, or **88%** of the estimated benefit from more efficient grid use. Figure 6.5 illustrates the compounding effect of these two errors.

Figure 6.5: Grossing up the wealth transfer benefit to consumers (not to scale)

All told, wealth transfers account for ~$2.3b or 88% of the net benefit estimate.



Given that the Authority went to the effort to account for this second wealth transfer – albeit erroneously – it is consequently difficult to understand why it did not endeavour to make some kind of adjustment when measuring the change in consumer surplus. After all, that calculation has substantially more bearing on the

269 Third Issue Paper, p.31.

270 *See:* cell M1 on the 'Summary grid use model' sheet of the Electricity Authority's 'Summary costs and benefits.xlsx' spreadsheet, published on 22 July 2019.

271 Importantly, the wealth transfer component of equation 10 reflects a *net* wealth transfer, i.e., the sum of the (positive and larger) wealth transfer from generators to final consumers due to lower wholesale prices and the (negative and smaller) wealth transfer from final consumers to generators from the reallocation of transmission (or interconnection) charges. Adding the $368m back simply converts the net wealth transfer from generators to final consumers into a larger *gross* one.

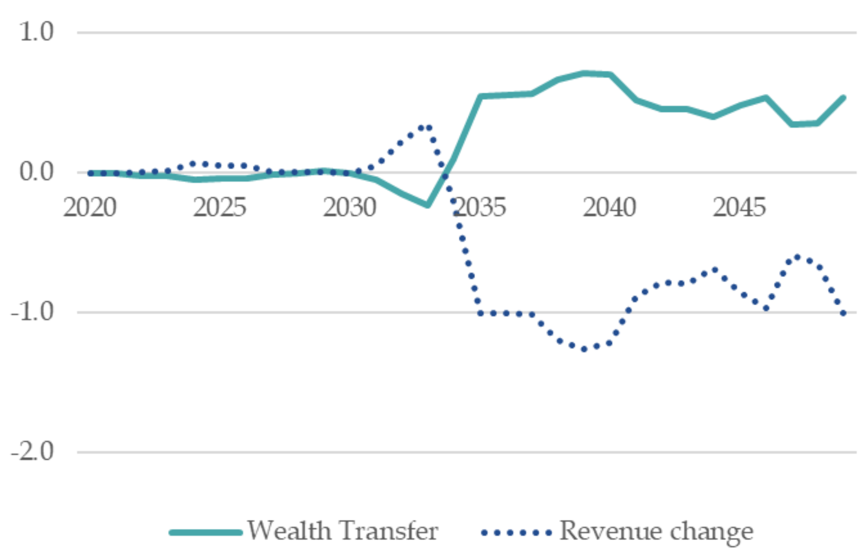
overall net benefit estimate. Strangely, at one point in its paper, the Authority contends that the reduction in nodal prices predicted by its grid use model would *not* give rise to a wealth transfer from generators to final customers. It offers a curious rationale:[272]

It is not possible for nodal prices to fall without existing generators losing out to end-consumers.

> *'Generators would not lose out to consumers, because, in the model, the falling prices are a result of generators expanding efficiently in response to increased demand and prices that justify the expansion. The expansion benefits both generators and consumers.'*

This explanation is not credible. Lower wholesale prices cannot benefit both the customers that are paying them *and* the generators that are receiving them. It is possible that some *new* generators might be better off, i.e., because they enter and earn at least a normal economic profit.[273] However, if that new entry causes wholesale prices to fall then, by definition, all *existing* generators would be unambiguously *worse off*. Money they would have earned at the higher wholesale price would flow to final customers, resulting in a very large wealth transfer. Figure 6.6 illustrates this point.

Figure 6.6: Comparison of transfer to generator revenue change ($billion, $2018)[274]



Wealth transfers are driving the benefit estimate.

Figure 6.6 compares the wealth transfer from generators to final consumers to the change in generator revenue. Unsurprisingly, the two curves are almost perfect mirror-images of one another. Higher wealth transfers from generators to final

272 Third Issues Paper, p.32.

273 However, the analysis set out in the previous section suggests that even *new* generators – i.e., those that enter in response to the modelled increase in wholesale prices – would often struggle to earn a reasonable return on their new investments. That is because of the aforementioned 'generation entry decision rule' which assumes that generators would invest without paying any attention to the potential impacts upon future spot prices.

274 Data are sourced from the 'AOB.csv', 'RCPD.CSV' and 'CS_results.csv' files for the 'All_major_capex' scenario. Generator revenue is calculated for a given year by multiplying the quantities for each backbone node and time period by the corresponding generator price and summing these together. A net revenue value is obtained by subtracting the interconnection charges faced by generators.

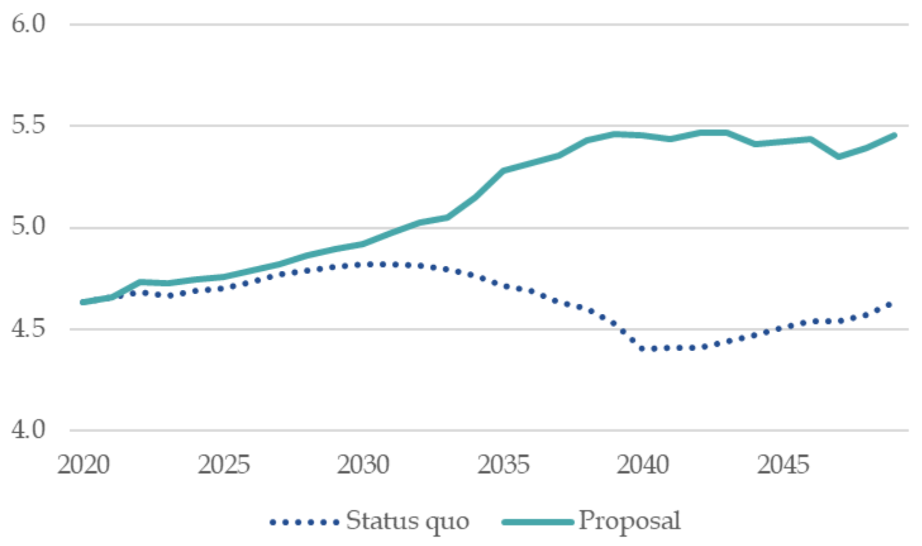
consumers correspond to lower revenues to generators, and vice versa. The two curves even cross the horizontal axis at the same point. Put simply, the lower wholesale prices are disadvantaging existing generators and resulting in enormous bare wealth transfers to final consumers. That is what is driving the benefit estimate.

6.3.3 Substantial additional costs have been ignored

The grid use model assumes that the removal of the RCPD price signal would lead to an increase in demand – particularly during peak periods. Figure 6.7 highlights the difference in peak demand under the Authority's proposal, relative to the status quo. The discrepancy is striking.

Figure 6.7: Peak consumption (TWh)[275]

Peak demand is forecast to be much higher under the proposal than the status quo.



To manage such an increase in peak demand, additional investment would be needed in:

- Transpower's transmission network;
- electricity distribution networks; and
- grid-connected generation.

The CBA picks up the first of these as a cost – which it estimates to be $188m[276] – but ignores the other two. It also disregards other costs likely to be associated with higher peak demand, such as any increase in carbon emissions. This introduces a clear source of bias into the analysis.

275 Data are sourced from the 'AOB.csv' and 'RCPD.csv' spreadsheets for the 'All_major_capex' scenario. The vertical axis is truncated to highlight the divergence in consumption.

276 In our opinion, this additional transmission investment cost is likely to be closer to $370m, for the reasons that we set out in Appendix B.5.4.

6.3.3.1 Distribution costs

In the case of electricity distribution costs, the Authority notes that:[277]

> *'The CBA does not include any costs for distribution network investment brought forward.* ***This is because the focus of the CBA is transmission, not distribution****. Accordingly, we have not evaluated either the incremental costs or the incremental benefits associated with the distribution network.*
>
> *On the benefit side, we have valued consumption at the price paid at the grid exit point (GXP), rather than the price paid at the customer's point of connection on a local network. This approach excludes the additional consumption benefits relating to the value that consumers place on the distribution network. The Authority is aware that most distribution networks around New Zealand have spare capacity.* ***It follows that incremental distribution costs of the proposal are likely to be low, and in the Authority's view, are likely to be exceeded by the incremental benefits associated with the distribution network****.'*

This is a very odd statement. The contention that the focus of the CBA is 'transmission' and that distribution costs can therefore be ignored is incorrect. The focus of the CBA is *not* on 'transmission' – it is on the costs and benefits that arise from a *proposed change in the TPM*. Consequential impacts on distribution networks are plainly part of that equation. Indeed, aspects of the CBA model clearly incorporate costs and benefits that are not elements of the transmission network – such as batteries, generation investments (in the top-down modelling), and so on. The Authority's statutory objective also refers to the electricity *industry*, not just sub-components of it.[278]

Additional distribution costs are clearly relevant to the CBA and should be included.

Distribution costs make up around 27% of consumers' bills – more than twice as much as the transmission component (10.5%).[279] Moreover, distribution network expenditure is influenced heavily by the need to manage peak demand. Put simply, increased peak demand leads to more investment and, in turn, higher consumer prices. Ignoring the impact that elevated peak period consumption would have on the distribution cost component of final customers' bills consequently undermines the usefulness of the CBA.[280]

As a conservative indication of this potential impact, the higher peak consumption over the 2020 to 2049 period corresponds roughly to a 1,388 MW increase in ratcheted peak demand at the backbone node level.[281] Assuming that the LRMC of

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277 Third Issues Paper, p.46.

278 *See: Electricity Industry Act 2010*, section 15.

279 See, for instance, Electricity Authority, 2018, *Electricity in New Zealand*, p.13.

280 The Authority's claim that most distribution networks in New Zealand have spare capacity is not credible either. Certainly, some areas of some networks will have spare capacity. But that cannot be the case everywhere on every network. If it were, then there would be no need for networks to forecast – and for the Commission to allow – augmentation expenditure as part of their default price path allowances. It would also be at odds with the Authority's own attempts to make distribution prices more cost-reflective. If no costs were associated with additional peak demand, then such reforms would not be needed.

281 This is calculated using the peak period quantity forecasts in the 'AOB.csv' and 'RCPD.csv' spreadsheets for each year and backbone node, converting them to an average MWh per hour (by

distribution network investment is between \$50–\$150/kW,[282] this would correspond to around \$27m to \$81m in additional expenditure over the period. This is a very significant amount given the size of some of the other costs and benefits that have been included in the CBA.

We note that the Authority has claimed that any such distribution costs would be 'more than offset' by incremental benefits. However, it is not at all obvious what benefits the distribution networks themselves would obtain, if any. Moreover, the benefits to consumers (e.g., from increased consumption during peak periods) are already factored into the CBA (i.e., they are wrapped up in the \$2.6b estimate). The Authority provides no indication at all as to what those benefits might entail. In our opinion, the most likely reason for this is that they do not exist.

6.3.3.2 Generation costs

In the case of the additional generation investment that is forecast to be required to meet the additional demand, the Authority recognises that this would give rise to both costs and benefits:[283]

> *'Additional investment in generation has both costs and benefits. The costs consist of the additional capital and operating expenditure for the additional generation plant. The benefits relate to the resulting reduction in wholesale electricity prices due to the increase in the supply of electricity into the wholesale market. That is, while the proposal is, in the shorter term, likely to cause an increase in energy costs, these are offset to some extent by increased generation investment.'*

The fact that the generation market is supposedly competitive is irrelevant.

The Authority's grid use modelling predicts that an additional \$1.9b of generation investment would occur if its proposal went ahead.[284] Clearly, that is a very large sum. However, its model includes only the benefits of that investment, not the costs.[285] The Authority offers the following rationale for that approach:[286]

dividing them by the 800 hours of peak period per year, or 1,600 30-minute trading periods). This simplification is conservative because, in practice, peak demand is not constant across the peak period, and is likely to be higher. Using peak 'observed' demand, ratcheted demand for a given year is calculated as the maximum observed demand for all years up to and including that year. If there is a drop in observed demand, then ratcheted demand does not change from the prior year. Ratcheted demand is used because it drives network investment.

282 See, for instance, Orion, 22 February 2019, *Methodology for delivering our delivery prices (from 1 April 2019)*, p.55, which includes an LRMC estimate of \$107/kVA (or ~\$86/kW assuming a power factor of 0.8). Various Australian electricity distributors report LRMC estimates of \$56/kW to \$119/kW for residential customers; *see for instance*: Jemena Electricity Networks, 20 September 2017, *Tariff Structure Statement 2016*, p.E-7; and Ausgrid, April 2019, *Tariff Structure Statement*, p.64. At an exchange rate of NZ\$1.06 per AU\$1, this equates to a range of \$60–\$126/kW.

283 Third Issues Paper, pp.37–38.

284 This is calculated by comparing the investment values reported in the 'generation_investment.csv' spreadsheet for the 'All_major_capex' scenario.

285 Although the Authority attempts to discount these benefits by averaging consumer surplus changes with and without energy price effects, it nevertheless includes some benefits from lower generation prices as we discussed above.

286 Third Issues Paper, p.47.

'The CBA does not include any costs for generation investment brought forward. This is because the generation sector is assumed to be competitive, so any generation investment that occurs as a result of the proposal ***is assumed to be efficient investment****.'* [our emphasis]

This explanation is unsatisfactory. Even if the wholesale market is effectively competitive, it does not follow that every investment decision made by generators is 'efficient'. Generators respond to the price signals that they are given. If the TPM supplies them with the 'wrong' signals, then the result could be inefficient investment outcomes. Indeed, the Authority has spent the last seven years explaining why, in its opinion, the current TPM does *not* produce efficient generation investment outcomes.

What the Authority is *really* saying here is that the additional generation expenditure can be disregarded *in this instance*, because it would be happening in response to *its preferred proposal*. That $1.9b in additional expenditure can therefore be *presumed* to be efficient and safely omitted from the CBA. The circularity in this logic should be self-evident: the analysis starts by assuming that the methodology being examined is efficient and then characterises everything that flows from it – even additional costs – as 'good'.

The Authority is assuming something that it should be testing.

This is no way to perform a CBA. It involves making an assumption about the proposal – i.e., that it is efficient – that the analysis is *supposed to be testing*. Put another way, the modelling has, in effect, commenced by 'first assuming the answer'. This introduces a clear bias into the CBA. The model should be including *all* the additional investments costs that would flow from the proposal – not just picking and choosing some and not others, based on a pre-conceived notion of which are 'efficient'.

In any case, even if the additional generation *would be* efficient (which does not seem plausible[287]), it *still comes at a cost* that should be included in the analysis. The fundamental idea of the CBA is to test whether those costs are outweighed by the benefits that are estimated to result, i.e., to measure *both* – not to include one and disregard the other. At the moment, the CBA is unsound, because it is:

Even if the additional generation investment would be efficient it still comes at a cost that must be included in the CBA.

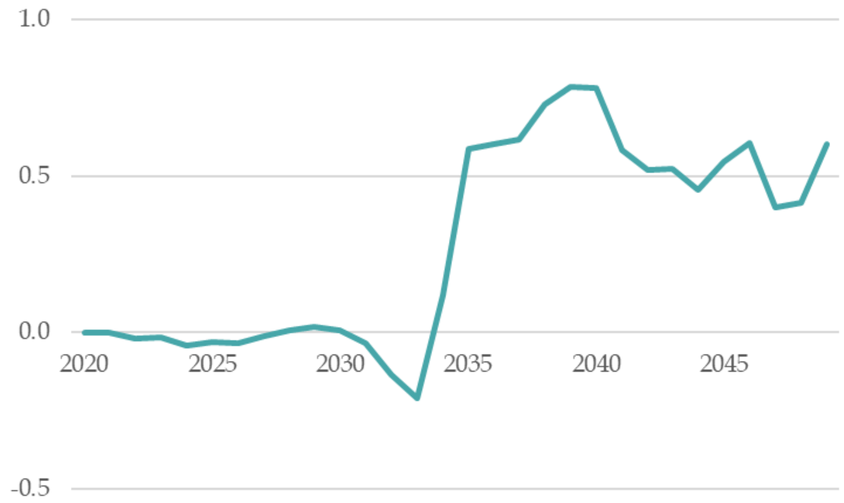
- measuring the supposed benefits of the new investment in generation including, for example:
  - the increase in consumer surplus arising from the lower estimated wholesale prices (most of which is a bare wealth transfer); and
  - the avoided costs of investments in batteries and DER; but
- *not* counting the cost of the investment that is needed to give rise to those benefits, i.e., the $1.9b in additional generation.

Indeed, in the model, consumer surplus increases significantly only *after* the forecast investment in new generation takes places, leading to significantly lower prices

[287] In our opinion it is highly unlikely that the $1.9b in new generation investment *could* reasonably be characterised as 'efficient'. In fact, it would be unlikely to transpire, in practice, for the reasons we set out in section 6.3.1

from 2034 onwards (see Figure 6.8 below).[288] We estimate that at least $2.1b of the increase in consumer surplus is due to generation prices changing, or roughly 95%.[289] It is therefore clearly the key driver. The model yields no benefits for the first twelve years and then the consumer surplus estimate shoots up as the forecast wave of new generation comes online in 2034.

Figure 6.8: Consumer surplus ($b, 2018 dollars)[290]



The CBA is measuring the forecast benefits arising from the new generation, but not the cost of it.

This treatment of benefits and the costs that give rise to them is therefore biased. The Authority's approach is analogous to measuring the net benefit that a child derives from a new car as the satisfaction she gets from it plus the avoided cost of bus fares, while ignoring what her parents or guardians had to pay for the vehicle in the first place. In other words, even if the additional $1.9b of generation investment was 'efficient' (which does not seem credible), it must still be included as a cost in the CBA.

6.3.3.3 Carbon emissions

In terms of carbon emissions, there is growing concern about the emissions that are produced during peak periods. There has also been increasing recognition of the

288 The consumer surplus gain remains significant even after changes in interconnection charges and transport costs are stripped out.

289 We estimate that $4.2b of the $4.4b in consumer surplus gain, calculated assuming that prices *do* change, is due to generation prices changing. This is estimated by using generation prices in the consumer surplus gain calculation, rather than prices including interconnection charges, transport costs and energy costs. Averaging the $4.2b consumer surplus gain with the equivalent value estimated assuming that prices *do not* change, gives at least $2.1b. Clearly, this analysis can only ever be indicative because it is using values that do not sit on the demand curve to estimate the consumer surplus gain. However, it does illustrate that most of the consumer surplus gain (around 95%) is driven by the change in generation prices. Data are sourced from the 'AOB.csv' and 'RCPD.csv' files for the 'All_major_capex' scenario. Equation 10 is used to calculate the change in consumer surplus.

290 Data are sourced from the 'CS_results.csv' file for the 'All_major_capex' scenario.

gains that could be made from reducing peak consumption. For example, the Energy Efficiency & Conservation Authority noted recently that:[291]

The Authority has stated that carbon costs are important, but they have not been considered.

> *'Reducing electricity demand at peak times is again shown to be a key opportunity for New Zealand to limit the need for more electricity infrastructure spending, and reduce emissions.*
>
> *A [Concept Consulting] report commissioned by the Energy Efficiency and Conservation Authority (EECA) shows cutting peak demand on winter evenings would have the biggest impact, as this eases pressure on electricity lines networks and expensive, carbon-intensive peaking generation.'*

The Authority explicitly ignores 'health or environmental policy objectives and outcomes' in its CBA.[292] However, that does not make them any less important to the New Zealand economy or to electricity consumers. In our opinion, those costs *should* be considered when assessing what changes should be made – if any – to the TPM. Indeed, the environmental costs of carbon emissions are just as important as the costs of investment in distribution networks and in generation.

6.3.4 The model does not reflect the Authority's actual proposal

The Authority explains that a key function of its proposed BB charge is to provide an implicit forward-looking 'shadow price' signal. As we explained earlier in this report, the idea is that customers would consider the impacts of their consumption and investment decisions on their future BB charges and, where appropriate, rationally self-ration. For instance, the Authority notes that:[293]

> *'…transmission customers that are required to pay a benefit-based charge for a future grid investment will have an incentive to take transmission costs into account in making decisions about their own investments and use of the grid.'*

A key function of the BB charge is to provide 'shadow price' signals.

It later elaborates that:[294]

> *'…charging users…for an investment after it is made is necessary to ensure that the efficiency benefits relating to new investments described above are realised. Over time, grid users' behaviour before a grid investment is made will likely adjust to reflect the charges they will face for the investment when it is made. If we do not charge the beneficiaries of the investments the full cost of the investment when it is made, then the behaviour of grid users before a particular investment is made will reflect this fact. We therefore consider that the best way to encourage users to take account of the full cost of the investment before it is made is to charge those who benefit from the investment the full cost of the investment when (after) it is made.'*

However, these 'shadow prices' are nowhere to be seen in the grid use modelling.[295] The demand and grid-scale generation investment equations used (and reflected in

291 Energy Efficiency & Conservation Authority, 29 March 2018, *Big benefits from reducing peak energy use*. Available: here.

292 Technical Paper, p.9.

293 Third Issues Paper, p.115.

294 Third Issues Paper, p.200.

295 As we note in section 6.4.1, the Authority has attempted to include shadow prices in its modelling of estimated benefits from more efficient transmission investment. The difficulty there is that those

the Python code) do not consider the impact that future transmission charges might have on current consumption and investment decisions. This is also evident in the charts included in the Issues Paper (e.g., Figures 6 and 7), which do not incorporate any 'shadow price' components.

These shadow prices do not feature in the grid use modelling. If they did, the results would be completely different.

If the modelling did incorporate these shadow prices – which are a core feature of the proposal – then the results would inevitably differ significantly from those published by the Authority. Without further analysis, it is hard to say for sure what impact shadow prices would have on the CBA net benefits. However, given all of the problems with the underlying economic theory, it is safe to assume that the impact would be negative.[296]

As it is, all that we can say for certain is that because shadow prices are an important part of the Authority's proposed methodology, it has not actually modelled its own proposal. This effectively renders this aspect of the CBA – which accounts for the vast majority of the estimated net benefit – irrelevant. At best, it is examining the merits of a proposal that is not even 'on the table'.[297] And, for the reasons set out in previous sections, the benefit estimate that the grid use model has produced for that irrelevant proposal is unreliable.

6.3.5 The model would produce the same answer for multiple options

The grid use model would produce the same net benefit estimate for virtually any approach comprised solely of fixed charges.

The grid use model not only neglects to reflect the methodology that the Authority has actually suggested, it would also predict exactly the same outcome for *any number* of alternatives. Provided that an approach is comprised *solely of fixed charges*, the grid use model would produce largely the same $2.6b benefit. There is no need for those fixed charges to be based on an estimate of private benefits. For example, the following methodologies would perform equally well:

- replacing the RCPD and HVDC charges with a single non-distortionary broad-based tax comprising only fixed charges, i.e., something akin to the proposed residual charge; or
- as implausible as it may seem, replacing the RCPD and HVDC charges with a purely random allocation of fixed charges, e.g., where each transmission customers' annual fixed dollar sums were drawn out of a hat.

shadow prices are based on expected *costs* of transmission investment, not private *benefits* to consumers, and so do not align with the Authority's proposal either.

296 As we explained earlier in this report, it is unrealistic to expect customers to be able to predict – and respond to – future BB charges, which the Authority has acknowledged in other contexts. Moreover, even if customers could anticipate their future BB charges, those prices would be sending *the wrong signals.*

297 This is the third time that the CBA has not modelled the methodology that has been proposed. The first CBA simply took an assumed 'efficiency parameter' and multiplied it by total electricity sector revenue – an approach that was roundly (and rightly) criticised as being devoid of merit. In that instance, there was no attempt at all to model the Authority's proposal. And in the OGW CBA an assumption was made that the methodology would provide forward-looking price signals equal to the regional LRMC of transmission. That did not reflect the proposal that was on the table either because, as we explained previously, BB charges (or AoB charges as they were known then) *would not be cost-reflective* – and certainly not equal to the regional LRMC of transmission. This has consequently been a recurring theme throughout the seven years of the TPM review.

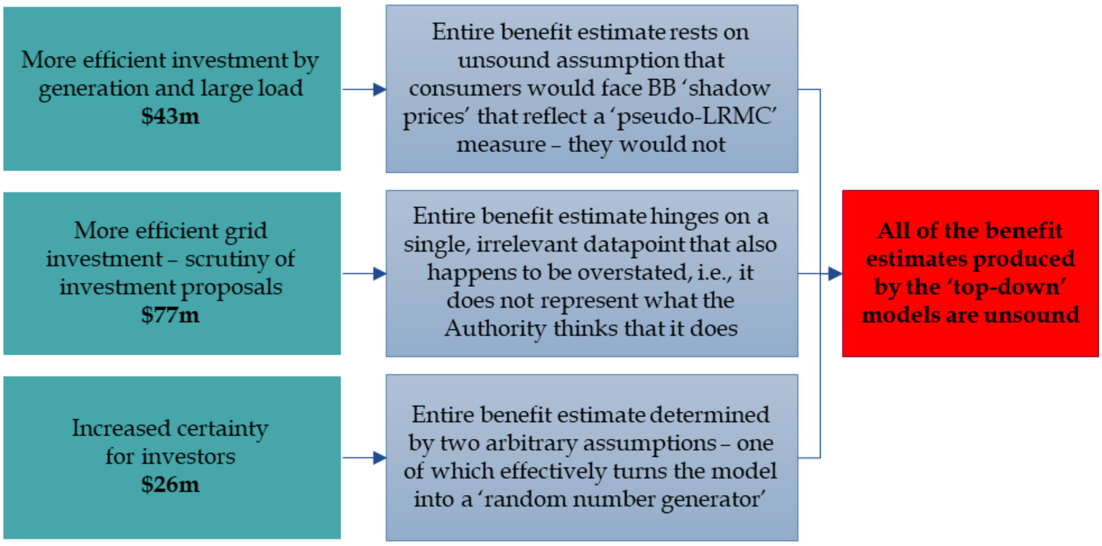
In other words, even taking the grid use model as given with its many flaws, the benefit estimate that it produces is *not* uniquely attributable to the Authority's proposal. What the model has *really* estimated is a benefit (albeit an erroneous one) that could be obtained by replacing the RCPD and HVDC charges with almost any variant of fixed charging. This is not symptomatic of robust modelling – particularly given the absurdity of the methodology described in the second dot point.

6.4 Top-down modelling

Top-down analysis is used to estimate the smaller and more bespoke costs and benefits. The three main categories of benefits are 'more efficient investment in generation and large load' ($43m), 'more efficient investment from greater scrutiny' ($77m) and 'increased certainty to investors' ($26m).

Top-down analysis is used to estimate the smaller and more bespoke costs and benefits.

Figure 6.9: Problems with the top-down modelling



As we explain in the following sections, and as Figure 6.9 indicates, all of these estimates are produced using deeply flawed methodologies and inputs. Consequently, none of these benefits estimates are robust.

6.4.1 More efficient investment in generation and load

The CBA uses 'Monte Carlo analysis' to simulate the potential benefits from efficient investment by generators and large loads. These benefits manifest in the form of reduced or deferred investment in the transmission network. This analysis assumes that generators and large loads (i.e., transmission consumers) would respond to expected *future* BB charges by reducing or shifting their generation and consumption to areas where the transmission network has more capacity, thereby reducing investment needs.

In other words, generators and consumers are assumed to respond to implicit shadow prices. However, just as with the OGW CBA, those shadow-prices do not reflect the price signals that customers would actually be facing under the BB

The model includes shadow prices – but the wrong ones. Those price signals would not reflect LRMC.

charging framework. They are again based on a simplistic measure of LRMC[298] which, as we explained in section 3.4.1, is wrong. In reality, the implicit price signals that each customer would face under the BB charge would be:

- impossible for all but the most sophisticated of customers to discern, even assuming they were inclined to respond to them; and
- *not* cost-reflective, i.e., BB shadow price signals would only resemble LRMC by sheer coincidence.

If accurate shadow pricing signals had been modelled, the result would be more likely to have been a net cost.

In other words, although the Authority has attempted in this particular model to replicate something resembling its own proposal by including shadow prices of a sort (unlike in its grid use model – see section 6.3.4), it has failed. Under the Authority's proposal, customers would face bespoke shadow price signals that reflected their subjective perceptions of benefits – and those signals would not reflect LRMC. That is *not* what the Authority has modelled and, indeed, it is not obvious how such an approach *could* be quantified.

For the reasons we set out at length in section 4, the BB charging methodology would be likely to cause load and generation to respond by making *inefficient* consumption and investment decisions. It follows that if the Authority had somehow managed to model its own proposal it would be unlikely to have concluded that benefits would arise from more efficient investment by generation and load. Instead, any such exercise would be more likely to have yielded a net cost.

6.4.2 Greater scrutiny of investments

The Authority has estimated that $77m in benefits would be obtained by consumers facing BB charges subjecting Transpower's investment proposals to greater scrutiny. We explained in section 4.3 why there is no reason to think that there is a problem with the Commission's grid investment approval process that needs solving. We also set out why the Authority's proposal would be likely to *compromise* those proceedings. In the interests of brevity, we do not repeat those points here.

There is no sound basis to think there are any benefits on offer from 'greater scrutiny of investments' by customers.

There is therefore no cause to think, as a matter of economic principle, that there are *any* benefits on offer from 'greater scrutiny of investments' by customers. The Authority's CBA does not establish otherwise. For starters, the Authority relies on just a single observation. Namely, it notes that the Commission reduced Transpower's proposed enhancement and development (E&D) base capex projects

298 Specifically, the Authority assumes that increases in peak demand give rise to additional transmission investment. It calculates this rate of incremental investment expenditure each year as: forecast incremental network expenditure in that year *divided by* the change in peak demand between the previous year and that year. This approach gives rise to estimates of expenditure per additional MW that vary from $178,822 (in 2026) to $2,895,453 (in 2032), taken from the example calculation in the 'Efficient investment' sheet of the 'Investment efficiencies model.xlsx' file. These are somewhat like pseudo LRMC estimates, calculated using only a year of expenditure and demand growth. These are the 'shadow price signals' to which customers are assumed to respond. They bear no resemblance at all to the *actual* price signals that would be provided by a BB charge.

allowance by 4.4% between the draft and final determinations for the second regulatory control period (RCPD2).[299]

From this single datapoint, the Authority assumes that it can apply efficiency factors of 4%, 2%, 1% or 0% to Transpower's proposed capex over the 2022 to 2049 period, depending on the type of expenditure. These assumed percentages applied to that future expenditure program yield the $77m benefit estimate. Relying on a single observation is inherently risky in the best of circumstances – and even more so when it is being used to project benefits out to 2049. Here, the problems are even greater, in that:[300]

- the 4.4% reduction followed scrutiny from *the Commission*, not *customers*, i.e., it is not a relevant metric because the Commission will be able to perform a similar oversight role for *future* transmission proposals – the reduction was not achieved because BB charges were in place (because they were not);
- the *relevant* question is whether reductions were on offer *above and beyond* those identified by the Commission and, given the multitude of practical factors described above, that seems highly unlikely if not implausible, i.e., the Commission is in the best position to identify potential efficiencies; and
- it is also possible that the Commission got its decision wrong – regulators and their advisors can and do make mistakes, which is one of the many reasons why it is imprudent to base an entire analysis on a single observation (and, in this case, on an irrelevant one).

The entire analysis is based on a single, irrelevant datapoint.

Perhaps even more problematically, the Authority appears not to have realised that its model assumes implicitly that the additional 4.4% that Transpower was proposing to spend would not have delivered *any benefits at all*. That assumption is not appropriate. It is virtually impossible to conceive of any scenario in which that additional capital expenditure would have delivered *zero* benefits. The Commission presumably determined simply that the benefits that would be delivered by the additional 4.4% of investment did not justify the cost. To use a simple example, if Transpower was proposing to spend $1,000 (to use a round number), the Commission might have determined that $44 (4.4%) of that sum would deliver only $40 in benefits and cut the allowance to $956. However, in this stylised example, the efficiency gain is not 4.4% ($44 ÷ $,1000), it is *0.4%* ($4 ÷ $,1000).

Not only is the single datapoint irrelevant, it is also inflated inadvertently.

299 Third Issues Paper, p.42.

300 The methodology is very similar to the approach the Authority used to arrive at its $173.2m net benefit estimate in its First Issues Paper. There, it multiplied total sector revenue (based on assumed growth rates) by an 'efficiency parameter' of 0.3%. The Authority sought to justify the selected efficiency parameter by comparing it to the long run total factor productivity (TFP) growth rate that had been applied by the Commission to determine the default price-quality paths for electricity distribution businesses. However, as Axiom's economists pointed out, these two factors were not measuring the same thing and the comparison therefore could not reveal anything meaningful about the robustness of the assumed value. The parallels here are quite striking. Here again, the Authority is multiplying large numbers (in this case, future capex projects) by efficiency factors that have been assumed, rather than estimated. And, once more, those assumptions have no sound basis. *See:* Green *et al*, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, pp.16-17.

In other words, even if the 4.4% datapoint upon which the Authority has based the entirety of this modelling was relevant (which it is not), it is *clearly the wrong number*. The *true* efficiency gain would be likely to be many magnitudes smaller than 4.4% and, by extension, the percentages that the Authority has adopted are also likely to be overstated substantially. As such, even on its own terms, the $77m estimated by the model is artificially inflated – most likely considerably.

The model ignores the additional costs that would arise from the extra scrutiny.

Finally, the model does not take into account the additional costs that Transpower, the Commission and stakeholders would incur as a result of that additional scrutiny. If the Authority's theory is to be believed, all parties would need to prepare or engage with additional material and participate fulsomely throughout the process, relying on internal resources and often external support. These extra costs would be significant, and none have been factored into the analysis.

6.4.3 Reduced uncertainty for investors

It is unclear whether it is appropriate to include this category of benefits in the CBA, given that the Authority has created the uncertainty in question.

The CBA assumes that investors would benefit from reduced uncertainty if the Authority's proposal was implemented – to the tune of $26m. There is no doubt that reduced policy uncertainty can lead to economic gains.[301] However, as we explained in section 5.2.1, prior to the October 2012, the TPM had been relatively stable. The extensive work of the two reviews that commenced in mid-2009 had concluded that, although the TPM was not perfect (which no pricing methodology ever is), there was no need for radical reform.[302]

Since that time, all the uncertainty has been created by the Authority's review, which has fallen short of best regulatory practice in numerous respects. For that reason, it is somewhat counterintuitive for the Authority to assert that a core benefit of its proposal ($26m) is 'increased certainty to investors'. In our experience, it is highly unusual – and arguably more than a little self-serving – for a regulator to assign a large benefit to clearing up the very uncertainty that it has created through its own actions.

In this particular instance, improved durability could be obtained far more simply by the Authority stating categorically that it is stopping its review and not contemplating any changes to the TPM for, say, the next ten years. Or, alternatively, certainty might be achievable if the Authority proposed a more economically orthodox reform option, such as an LRMC-based pricing option – a candidate suggested by several parties throughout the review. In contrast, it is highly unlikely that the proposed option would do much – if anything – to reduce uncertainty.

Throughout this report we have documented the plethora of problems that would afflict the proposed methodology if it was to be implemented. Substantial uncertainty would surround the estimation of benefits, the durability of those charges over time, the scenarios in which they would be revisited and, ultimately, the durability of the regime. In our opinion, there is a very good chance that these

301 Third Issues Paper, p.44.

302 The main exception to this was the cost allocation enshrined in the HVDC charge.

There are many potential ways to improve certainty for investors – but the proposed methodology is not one of them.

problems would render the methodology unsustainable and prompt major changes to be made in the near-term to make it more workable.

All of these practical realities are ignored in this aspect of the CBA modelling. On its face, the model appears to be very sophisticated. However, when the elaborate computer code is stripped away it becomes apparent that the results are driven primarily by two crucial inputs; namely:

- an assumption that the proposed TPM would defer the frequency of 'uncertainty' events (i.e., a major review of the methodology) from 1 every 10 years to 1 every 11 years; and
- the selection of '100' as the benchmark level of uncertainty – which is an assumption that is required to translate the top-down modelling framework into a benefit estimate.

The modelling hinges primarily on two arbitrary assumptions that have no empirical foundation.

There is no objective empirical basis for either of these inputs. As for the first assumption, no analysis at all is presented to justify the selection of the 10- and 11-year periods. They are guesses. Changing those intervals has a substantial impact on the estimated benefit. For example, if one assumes instead that the proposal would lead to an 'uncertainty event' once every 21 years instead of every 20 years, the estimated benefit drops to around $15m. It is alarming that the result is so sensitive to such a spurious assumption. The second input is even more worrisome.

The second assumption undermines completely the efficacy of the modelling. In order to produce a benefit estimate, the model must assign a baseline 'value' to uncertainty. Ideally, the benefits estimate would not hinge upon that number. After all, it is a purely random baseline value – it is not something that *can* be quantified. In other words, it should not matter whether the model uses 1, 100, 1,000 or 1,000,000,000 for that 'baseline' value. Each of those equally viable candidates should yield *the same answer*.[303]

It is not exaggerating to say that this model is little more than a random number generator.

But they do not. The Authority picks a baseline value of 100 – as good a selection as any other – and this produces a benefit estimate of $26m. However, if it had picked 1,000 – a no less viable candidate – the benefit would have been more than 10 times higher, at over $260m.[304] And if it had selected a baseline value of 1 – which, again, is no more 'right or wrong' than any other number – the benefit estimate would be nearly zero. This problem is fatal to the model's credibility. It is no exaggeration to state that the model is little more than a random number generator.

The Authority presumably tested a variety of different combinations of inputs before deciding upon 10-years/11-years and 100. That begs the question: why did it decide upon 100 instead of, say, 1 or 1,000, or on 10- and 11-year periods instead of, say, 15- and 16-year windows? The most logical answer is that those values were selected because of *the benefits value they were producing*, i.e., the number might have

303 For example, changing the base value in the consumer price index (CPI) from 1,000 to 10,000 would not change the estimated quarterly rate of headline inflation.

304 This would be the equivalent of Statistics New Zealand changing the base value in the CPI from 1,000 to 10,000 and concluding that the quarterly rate of headline inflation was 10% instead of 1%.

'seemed about right'. However, that is reverse engineering and not an appropriate way in which to perform a CBA.

6.5 Other issues

There are several other issues with the modelling that raise further questions about the net benefit estimates.

6.5.1 Inclusion of historical investments

The net benefit estimate goes up by $18m if BB charges are not applied to any existing investments.

The Authority's net benefit estimate goes up by $18m if the seven existing investments flagged for BB prices are excluded and subjected only to the non-distortionary residual charge.[305] This is unsurprising. As previous Axiom reports have explained at length, no dynamic efficiency benefits can be achieved from reallocating 'sunk costs', but there *is* the clear potential for static efficiency costs to arise. The CBA serves simply to reinforce this widely accepted economic proposition.

The reasons offered for including the seven existing investments anyway are not persuasive.

Nevertheless, the Authority suggests that those seven existing investments should still be reallocated via the BB charges. It begins by stating that $18m is 'not significant in the context of the scale of the benefits estimated'[306] and can therefore be ignored. However, as we have seen, the $2.6b net benefit is substantially overstated. In reality, $18m is a *very substantial* number relative to the *true* net benefit of the proposal, which is more likely to be zero, or negative. And in any case, $18m is not much less than the $26m benefit that the Authority includes from 'improved certainty for investors', which is clearly considered to be material.

The Authority then contends that including the seven existing investments would give rise to various 'unquantified durability benefits'. It must therefore believe that the value of these 'durability' benefits *exceeds* $18m. For the reasons we set out earlier, there is no compelling reason to think that there would be *any* benefits from improved durability. In our opinion, the proposal would compromise durability. Consequently, even taking the CBA model at face value, there would appear to be no justification for reallocating the past costs of any existing investments.

6.5.2 Statistically insignificant results

When the inputs and outputs to the various regression models are examined more closely even more problems emerge. In particular, several key inputs to the grid use model are statistically insignificant or based on regression estimates that are mathematically meaningless.[307] For example:

305 Third Issues Paper, p.49.

306 *Ibid.*

307 There are also several examples of calculation or formula errors throughout the modelling, as we explain in Appendix B.4.3.

- thirty-six estimated elasticities used in the *time of use demand model* are statistically insignificant at the 5% level – which is almost half of the parameters estimated from that model;[308]

The modelling is full of statistically insignificant outputs and inputs.

- the model-fit statistics for the chosen *aggregate, first stage, model of distribution-connected load* econometric model (an adjusted R^2 of 0.58 and an F-statistic of 88.11) suggest that there is a significant amount of variation in actual demand left unexplained by the model;[309]
- four of the six parameters estimated from that same model are statistically insignificant at the 5% level – one of which (the income elasticity of 0.11) is used as a direct input to the grid use model; and[310]
- similarly, six of the fourteen parameters estimated from the translog cost model used in the *aggregate, first stage, model of industrial demand* econometric model are statistically insignificant at the 5% level.[311]

Given that it is inherently difficult fitting theoretical econometric models – such as those reflected in the 'almost ideal demand system' used in the CBA – to real world data, it comes as no surprise that the Authority has wound up relying on so many statistically insignificant parameter estimates and model specifications. Nevertheless, because they *are* statistically unreliable, it is necessarily the case that the results from the grid use modelling that relies on them must *also* be unreliable. After all, 'rubbish in; rubbish out'.

6.5.3 Time pattern of net benefits

The time-profile of the Authority's net benefit estimate is very peculiar. Figure 6.10 illustrates the cumulative NPV of the net benefits forecast to arise from the Authority's proposal over time. The green line is simply the result that comes out of the Authority's CBA – with all the errors described hitherto still in play. It shows that, even with all those mistakes left unaddressed, the projected net benefit is *virtually zero* up until around 2034. Then, at that twelve-year mark:

308 This was determined by first using R to run the code in the 'TOU_demand_model.R' file and then analysing the regression statistics contained in the 'laaids_mass_sd_restr_x' and 'laaids_dc_sd' R objects. The time of use model is applied by fitting equation 21 of the Technical Paper separately to actual data for distribution-connected and the equivalent for transmission-connected demand – giving 84 estimated parameters, of which 36 were not statistically significant at the 5% level (43% of the total number of parameters). If just the 48 parameters shown in Table 12 of the Technical paper are considered, then 19 of the 48 estimated parameters are not statistically significant at the 5% level (or 40%).

309 These statistics are shown in Table 10 of the Technical Paper. Comparing the statistics for the other models tested by the Authority, shown in the other columns of that table, suggest that noticeable changes to model structure and resulting parameter estimates do not materially change the model fit. For instance, the specification in column 'C' includes a statistically significant own price elasticity of -0.29 (compared to the -0.11 adopted in the CBA), with the same number of variables, a slightly lower F-statistic higher and a slightly higher adjusted R^2.

310 Again, this can be seen in the results shown in Table 10 of the Technical Paper.

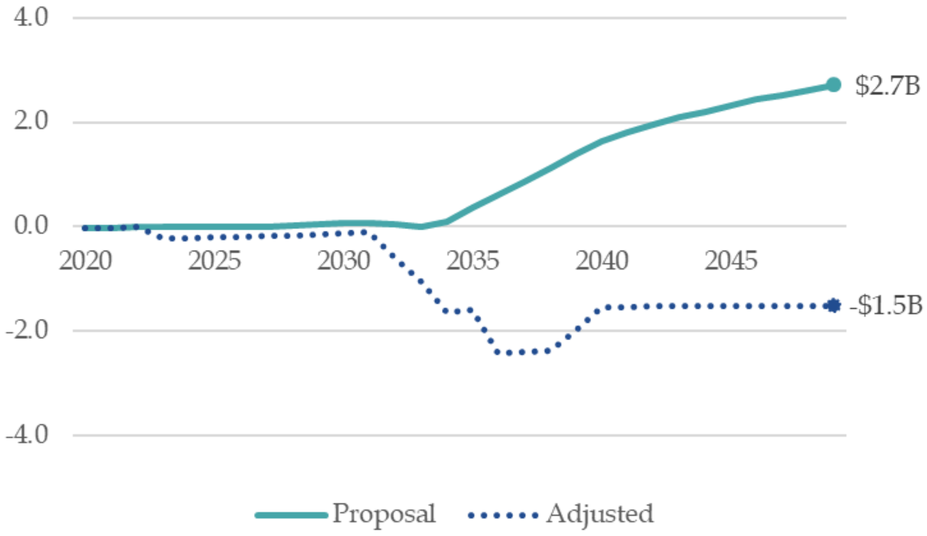
311 This can be seen in the 'cost_function_results.csv' output file generated when running the 'CostFunctionEstimation.R' script in R.

- an influx of new generation is forecast to take place (unrealistically, for the reasons described in section 6.3.1);
- forecast wholesale prices drop sharply (a wholly predictable outcome that generators are assumed to ignore); and
- from that point forward, net benefits grow steadily (remembering that almost all of this a bare wealth transfer and therefore not an efficiency benefit at all).

The dotted blue line shows what happens to the NPV of net benefits if the modelling is adjusted to address two of the more obvious errors – namely, to *exclude* the $2.3b of wealth transfers and to *include* the $1.9m of additional generation costs. This partially corrected cumulative estimate – now of a substantial net *cost* – follows a broadly similar trajectory through time.

Figure 6.10: Cumulative net benefits by time (NPV terms, $billion, $2018)[312]

Taken at face value, the CBA suggests that there would be no significant net benefit (in NPV terms) until ~2034.



The time profile of costs and benefits depicted in Figure 6.10 calls into question why the Authority is seeking to reform the TPM now. It has stated that it considers that changing the TPM is necessary and becoming increasingly urgent, since it is supposedly leading to inefficient investment and consumption outcomes.[313] Yet even taking its own CBA modelling at face value – with all its flaws – then:

- the proposal would not deliver a significant net benefit in NPV terms for *twelve years*; yet

312 Data used to generate the net benefit profile were sourced from the 'CS_results.csv', 'total_dg.csv', and 'transmission _costs.csv' files for the 'All_major_capex' scenario, the 'transmission_costs.csv' file from the 'Demand_major_capex' scenario, the 'Investment efficiencies.xlsx' and 'Summary of costs and benefits.xlsx' files and results from applying the Python code were used to estimate investment efficiency benefits.

313 Third Issues Paper, p.ii.

- as we mentioned earlier, the Authority expects that there would be a significant 'uncertainty event' – such as a major TPM review – after *eleven years.*[314]

The CBA model is suggesting that there would be eleven years of virtually no net benefits and then the TPM could change substantially.

In other words, even on its own terms, the CBA model is suggesting that there would be eleven years of virtually no net benefits and then the TPM could change substantially. Consequently, even if all the errors in the CBA are ignored there is still no obvious reason to implement the Authority's proposed option – and certainly not as a matter of urgency.

Based on its own modelling assumptions, the proposal might deliver barely a dollar in net benefits before the methodology changes again. Moreover, even if those future benefits were not largely (if not entirely) illusory (which they appear to be in this case), it is doubtful that *any* model could make predictions with any reasonable degree of certainty so far into the future.

6.6 Summary

The modelling CBA contains a plethora of errors – some very serious. Several are sufficient in their own right to cast considerable doubt over the efficacy of the Authority's net benefit estimate. In culmination, they serve to undermine completely the reliability of that result. In our opinion, the new CBA is just as flawed – if not more so – than its ignominious predecessor. Indeed, many of the errors that have been made in this latest model are eerily similar to those made by OGW and/or by the Authority in the CBA in its First Issues Paper.

Once these shortcomings are recognised, it is simply not possible to conclude that the Authority's proposal would deliver a net benefit to New Zealand's economy or improve the overall efficiency of the electricity industry. For example, addressing just two of the more obvious errors (the accidental inclusion of wealth transfers and the inappropriate exclusion of additional investment costs) would reduce the estimated net benefit to **-$1.5b**, i.e., it would become a **net cost**.[315] Ultimately, just like its predecessors, this CBA is of no probative value.

314 As we indicated earlier, this eleven-year assumption has no objective basis. It is simply taken 'as given' here for the sake of illustration.

315 To be clear, we are not suggesting that the -$1.5b represents a sound estimate of the likely net benefit – or cost in this case – from implementing the Authority's proposal. It is simply the revised result that one obtains when the two issues are addressed. Even with those corrections, the CBA remains manifestly unfit for its intended purpose on account of the many other shortcomings identified in this report.

Appendix A Description of the CBA modelling

The CBA modelling is very complex. It involves numerous steps, several different quantitative models and tens of thousands of lines of computer code. It is virtually impenetrable to all but a select audience – and the Technical Paper is not especially illuminating. Consequently, in this appendix we seek to provide a clearer explanation of how the CBA has been performed and the specific inputs, assumptions and components that have influenced the results. Appendix B then explores the many problems with the modelling.

A.1 Overall approach

The CBA attempts to compare the estimated costs and benefits that would arise if the current TPM was replaced with either the Authority's proposal or another alternative. This involves several steps:

- defining the status quo or base case (i.e., the outcome if the current TPM were to remain);
- identifying relevant costs and benefits;
- estimating those costs and benefits – and the net benefit – for each alternative to the status quo; and
- comparing the net benefits before concluding whether the proposal or the alternative option is better than the status quo.

Judgement was required in each step, with the Authority rightly recognising that a CBA 'is not a precise exercise'.[316]

A.1.1 Scenarios: the status quo and alternatives

The Authority adopts as its status quo the current TPM – and assumes that it would remain in place. All costs and benefits are estimated relative to that current methodology. However, that is not the correct approach. The Authority is reviewing the TPM *guidelines*. There are many different ways in which Transpower might change the current pricing methodology within the existing guidelines, e.g., by increasing the number of periods over which contributions to RCPD are measured.[317] In other words, the CBA immediately gets off on the wrong foot.

The Authority then chooses to compare that unduly narrow formulation of the status quo to its proposed TPM and one alternative.[318] It does not consider other options, including those proposed by stakeholders previously, such as LRMC pricing. This is perplexing, because it contradicts the advice contained in the Authority's own LRMC paper, which recommended that the option be tested

316 Third Issues Paper, p.20.

317 This is precisely what Transpower did in its first operational review and what it was considering doing again in the second review before it was subsequently abandoned.

318 This is discussed in Appendix E to the Issues Paper.

further through a CBA.[319] The Authority has had more than two years to perform the modelling, which makes these omissions even more conspicuous.[320]

A.1.2 Relevant costs and benefits

The CBA assesses a defined set of costs and benefits using the range of estimation approaches and tools summarised in Table A.1. The Authority acknowledges that it does not include certain categories of costs and benefits, including:

- unquantified avoided inefficient investment in emerging technology by mass-market consumers;
- avoided costs of undergrounding;
- any additional costs of distribution or generation investment; and
- effects on industries, markets or policy objectives outside of the electricity sector, including any environmental effects.

Table A.1: Selected costs and benefits

Category	Description	Estimation approach	Estimation tool
Benefits			
More efficient grid use	Increased use of electricity at times when it is valued most highly by consumers	Present value of change in consumer surplus estimated by comparing projected changes in prices and usage *plus* the increase in interconnection charges paid by final consumers	Grid use model
More efficient investment in DER	Reductions in investment in DER (grid-scale) batteries for the main purpose of avoiding transmission charges	Present value of projected avoided investment in batteries	Grid use model
More efficient investment by generators and large consumers	More efficient investment by generators and large consumers (since they would supposedly account for the costs of grid upgrades when making decisions) leading to reduced transmission investment	Present value of estimated reduction in total transmission investment	Top-down analysis / Monte Carlo simulation
More efficient grid investment – scrutiny of investment proposals	More efficient grid investment by Transpower due to greater scrutiny of its expenditure proposals from interested consumers and less lobbying for inefficient investments	Present value of expected reduction in grid investment caused by additional scrutiny estimated by multiplying projected capital expenditure by either 4%, 2%, or 1%, depending on expenditure category	Top-down analysis

319 Electricity Authority, *Nodal pricing and LRMC charging*, p.2.

320 It is also inconsistent with the Authority's Decision-Making and Economic Framework (DMEF) which, as it has acknowledged previously, 'ranks' LRMC-based approaches *higher* on the list of options than BB charging methodologies. We continue to think that the DMEF is not a useful tool but, even so, it is curious that it has been cast aside so swiftly in this instance.

Category	Description	Estimation approach	Estimation tool
Increased certainty for investors	Increased certainty reduces the required return on investment	Present value of change in total surplus estimated by simulating the impact on supply, demand and prices of reducing the frequency of 'uncertainty' events (from one every ten years to one every eleven years)	Top-down analysis / Monte Carlo simulation
Costs			
TPM development and approval costs	Costs such as policy analysis, modelling and legal fees	Detailed build-up of the employee / contractor time and cost needed based on Transpower's 2016 estimate of its TPM development costs, plus expected costs of legal challenge	Bottom up build of costs
TPM implementation costs	Costs of computer hardware and software, development and testing and user training	Detailed build-up of the employee/contractor time and cost needed based on Transpower's 2016 estimate of its TPM implementation costs, plus expected costs of legal challenge	Bottom up build of costs
TPM operational costs	Costs of data gathering and management, invoicing and customer liaison	Detailed build-up of the employee / contractor time and cost needed based on Transpower's 2016 estimate of its TPM operational costs	Bottom up build of costs
Grid investment brought forward	Cost of transmission investment occurring earlier to cater for increases in peak demand	Present value of the projected increase in direct grid investment caused by the increase in peak demand	Grid use model
Load not locating in regions with recent grid investment	Distortion from large energy-intensive consumers avoiding investing in a region that has a BB charge	Present value of estimated increase in total transmission investment caused by large consumers not relocating to where there is more transmission capacity	Top-down analysis / Monte Carlo simulation
Efficiency cost of price cap	Suppressed demand from customers with uncapped charges	Present value of change in consumer surplus and revenue recovered from load estimated by comparing projected changes in prices and usage from applying the price cap	Grid use model

A.1.3 Estimation tools

The Authority uses three main estimation tools (or 'assessment methodologies') to estimate the costs and benefits. These are:

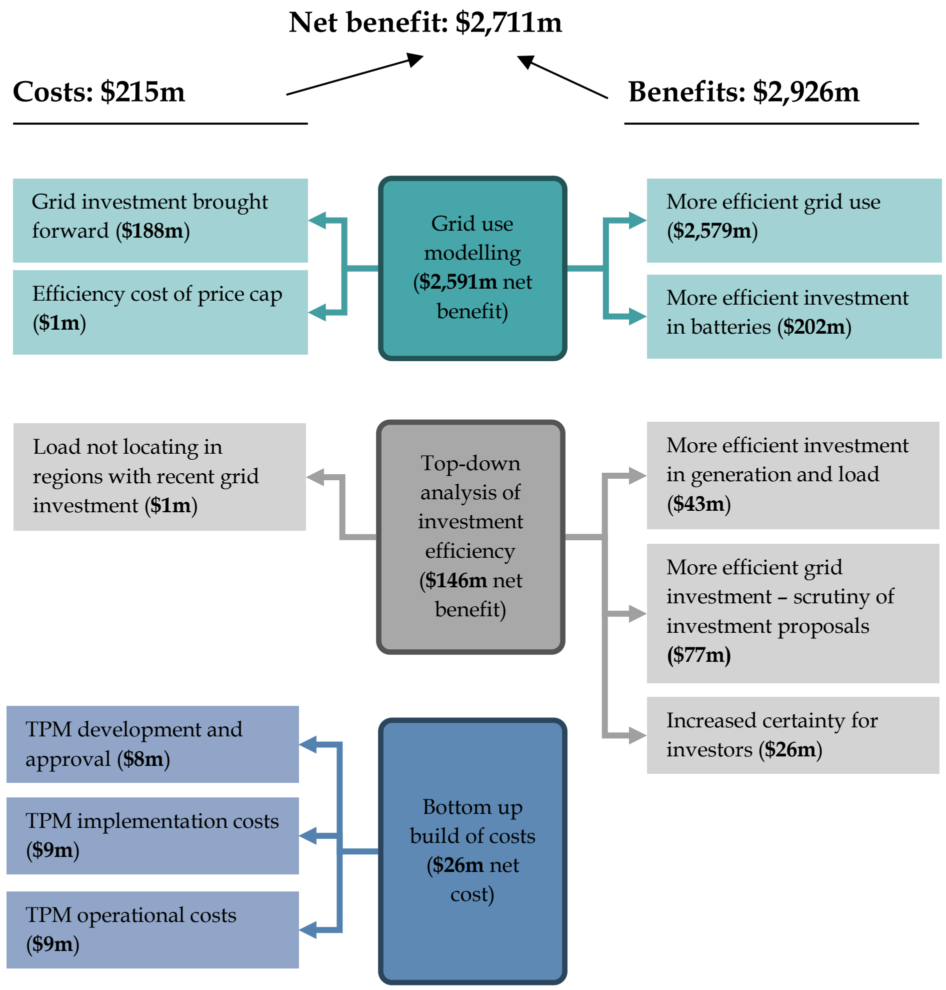
- **A grid use model** – this is used to analyse how consumption, generation, prices and investment change in response to different TPMs and demand or investment scenarios. The model relies on:

– assumed decision rules (e.g., when to invest in generation or batteries) and economic relationships (e.g., demand);
– parameter inputs (e.g., elasticities) estimated by fitting econometric models to historical data; and
– data sourced from Statistics New Zealand and the Authority's own Electricity Market Information database.

- **Top-down analysis** – this is used to assess how investment efficiency, scrutiny and certainty may change in response to different TPMs. This analysis relied on:
  – Monte Carlo simulation of assumed distributions, based largely on the Authority's judgement;
  – assumed economic relationships and input parameters (e.g., changes in the number of uncertainty events if the TPM proposal was adopted); and
  – historical and forecast peak demand, expenditure and generation capacity data.
- **Bottom-up build of costs** – this is used to estimate the costs for developing, implementing and operating a new TPM. It relied primarily on Transpower's 2016 estimate of applying a complex TPM and the Authority's judgement.

Different tools are used to estimate values for different costs and benefits, as Figure A.1 summarises. The values shown are those for the central case of the Authority's proposal. The lion's share of the net benefit is estimated using the grid use model – which is considered further in section A.2.

Figure A.1: Summary of CBA approach (central case)



A.1.4 Inputs and outputs

The Authority relies on a wide range of inputs, assumptions and estimated parameters to apply the three sets of assessment tools. These include (among many others):

- historical electricity volumes and prices (for generation, demand, and transportation) by backbone node;
- annual energy volumes by industry from the Ministry of Business, Innovation and Employment (MBIE);
- national account data and employment statistics from Statistics New Zealand;
- Transpower's latest revenue forecasts (used to estimate transmission costs);
- lists of available potential new generation (including capacity and cost);
- details about the cost and configuration of grid-scale batteries based on the 100MW Tesla battery recently installed in South Australia;
- population and income growth projections from Statistics New Zealand;
- Transpower's 2016 estimate of complex TPM development, implementation and operational costs; and

- a social discount rate of 6% in real terms.

After using these inputs to apply the three estimation tools, the Authority estimates the costs and benefits set out in Table A.2 for both the proposal and the alternative option. The bracketed ranges reflect differences in input assumptions and methodologies considered more or less conservative than the central case (which is not bracketed). To calculate its ranges, the Authority subtracts the 'high costs' estimate from the 'high benefits' estimate; and the 'low costs' estimate from the 'low benefits' estimate.[321]

Table A.2: Summary of quantified costs and benefits ($m)

Quantified benefits	Proposal	Alternative
More efficient grid use	$2,579 ($81 - $5,678)	$1,775 ($4 - $4,197)
More efficient investment in batteries	$202 ($137 - $786)	$222 ($137 - $786)
More efficient investment in generation and large load	$43 ($9 - $112)	–
More efficient grid investment – scrutiny of investment proposals	$77 ($29 - $125)	–
Increased certainty for investors	$26 ($10 - $48)	–
Total quantified benefits	**$2,926 ($266 - $6,749)**	**$1,997 ($141 - $4,983)**
Quantified costs	Proposal	Alternative
TPM development / approval	$8 ($4 - $12)	$6 ($3 - $8)
TPM implementation costs	$9 ($4 - $13)	$4 ($2 - $5)
TPM operational costs	$9 ($5 - $14)	$0.3 ($0.2 - $0.5)
Grid investment brought forward	$188 ($51 - $324)	$135 ($6 - $264)
Load not locating in regions with recent grid investment	$1 ($0 - $2)	–
Efficiency costs of price cap	$1	–
Total quantified costs	$215 ($65 - $366)	$144 ($11 - $278)
Results		
Net (benefits less costs)	**$2,711 ($201 - $6,383)**	**$1,853 ($130 - $4,705)**

Source: Third Issues Paper, Table 4, p.21

A.2 Grid use model

The grid use model is used to estimate 96% of the net benefit – and so makes up the core of the CBA. This section elaborates on how that model functions and the key outputs that it produces.

A.2.1 A series of relationships

The grid use model is essentially a set of equations used to explain how demand, prices, generation and investment relate to one another. The Technical Paper uses 29 equations to explain how the model works, grouped into three 'models':

1. **A demand model (24 equations)** – which is used to model the relationship between prices and demand in what is referred to as an 'almost ideal demand

321 As we highlight subsequently, that is not an appropriate manner in which to derive a range.

system' based on economic theory. Some of the equations are used to estimate parameter inputs, such as elasticities. Others are used to iterate demand and prices over time (i.e., over the horizon out to 2049). And others are used to estimate changes in consumer welfare.

2. **A generation investment model (1 equation)** – which uses an investment decision rule and a schedule of potential investments to model what generation is installed and when. The decision rule assumes that potential investors look at current profitability when deciding whether to invest, not future revenues. The generation investment model interacts with the demand model in two important ways:
   - investment is made in any year in which the prices produced by the demand model for the previous year generate enough revenue to cover long run marginal costs and interconnection charges assuming that all capacity is dispatched; and
   - the prices produced by the demand model are affected by the amount, location and cost of dispatching installed generation.
3. **A DER investment model (4 equations)** – which also uses an investment decision rule and assumed battery configuration (e.g., life, capacity, cost, efficiency) to model what battery capacity is installed and when. The decision rule assumes that potential investors look at current grid delivered prices and expected transmission charges when deciding whether to invest. The DER investment model also interacts with the demand model in two crucial ways:
   - battery investment is made when the prices produced by the demand model generate enough revenue to cover long run marginal costs and expected peak transmission charges; and
   - the quantity demanded arising from the demand model is affected by the amount and location of battery investment.

The Authority operationalises the grid use model using statistical software called 'R' and the programming language 'Python'.

A.2.2 Modelled outcomes

Based on the inputs, assumptions, and assumed relationships, the grid use model predicts some curious outcomes, which we describe below.

A.2.2.1 *The status quo*

In the status quo (i.e., assuming that the current TPM remains), the model forecasts that:

- aggregate annual consumption would increase by 19% over the period from 2020 to 2049, with significantly greater consumption during off-peak periods (roughly 67%) – this is in line with forecast growth in connections (of 23%);

- average[322] prices faced by consumers – including interconnection charges, transport costs and energy prices – would increase by 15% in real terms over the same period, while average prices paid to generators would increase by 12%;
- generation investment would be modest, at $6.5b in total over the period to 2049, with significant battery investment starting from 2027 at $0.5b; and
- aggregate annual generation revenue would increase in line with forecast consumption, albeit by slightly more (at 34% from 2020 to 2049).

A.2.2.2 *The Authority's proposal*

The status quo predictions are set out in Figure A.2 to Figure A.9 and compared to those predicted under the Authority's preferred proposal. The key differences being that under the latter:

- consumption is slightly higher (by roughly 0.4%), while connection numbers remain the same – implying a slight increase in consumption per final consumer;
- peak consumption is higher over the period (by about 11%), with a noticeable divergence (from the status quo) from 2030 onwards;
- average prices faced by consumers and average prices paid to generators are noticeably lower from 2034 onwards, after increases in 2033;
- generation investment increases significantly by $3.8b to $10.3b in total over the 2020 to 2049 period, while generation revenue reduces by $13.2b (net of interconnection charges);[323] and
- battery investment is significantly lower (at only $91m).

Based on these observations it appears that, under the Authority's proposal, three key things are happening:

1. Peak consumption is forecast to increase in the early 2030s in a way that pushes up peak prices over 2031 to 2033.
2. This increase in peak prices then leads to significant investment in new generation in 2034 and 2035.
3. That new generation investment pushes down the prices paid by final consumers and paid to generators from 2034 onwards.

This sequence of events is consistent with the Authority's own interpretation:[324]

> *'Under the proposal, we expect that increased peak demand (caused by the removal of the RCPD charge) would lead to an increase in peak wholesale energy prices and greater expenditure on electricity (from grid-connected generation).[61] This increase would not be*

322 Here, 'average' is calculated on a per MWh basis.

323 Both values are in total dollar terms. Note that generation investment increases by $3.8b in *total* over the 2020 to 2019 period relative to the status quo, and by $1.9b in *NPV terms*.

324 Third Issues Paper, p.37.

much compared to the removal of the RCPD charge. At the same time it would stimulate investment in generation capacity and so lead to lower energy prices.'

As we explain later, it is this reduction in prices that leads to the significant increase in consumer surplus estimated by the Authority that accounts for 96% of the $2.7b in net benefits.

A.2.2.3 *Projected consumption*

Figure A.2 and Figure A.3 compare the annual consumption and peak consumption projected for both the status quo and the proposal.

Figure A.2: Comparison of annual consumption (TWh)[325]

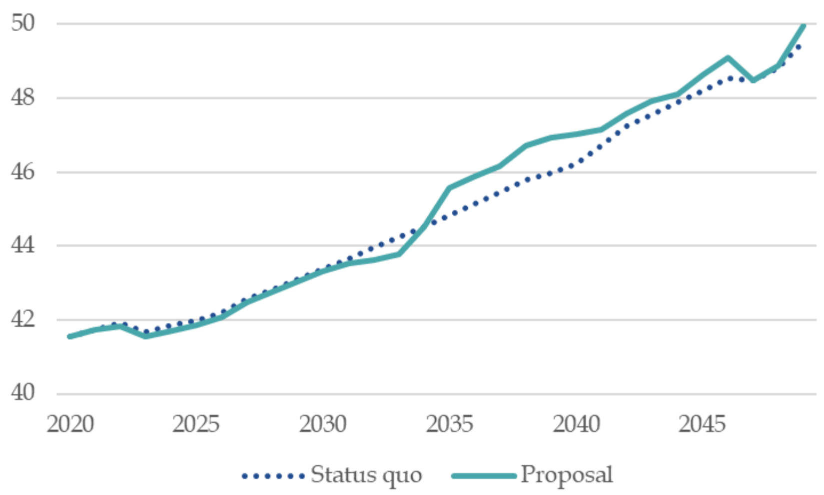
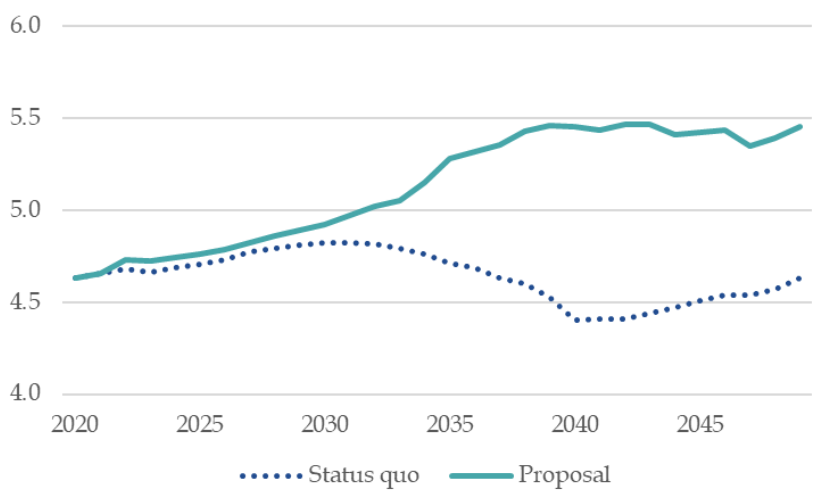


Figure A.3: Comparison of peak consumption (TWh)[326]



325 Data are sourced from the 'AOB.csv' and 'RCPD.csv' files for the 'All_major_capex' scenario and includes consumption for all backbone nodes.

326 *Ibid.*

The figures highlight that, from 2030, peak consumption drops in the status quo but increases markedly under the proposal, despite aggregate consumption following a very similar profile across the two options.

A.2.2.4 *Projected prices*

Figure A.4 and Figure A.5 compare the projected average consumer and generation prices. They show an increase in prices that occurs over the 2031 to 2033 period under the Authority's proposal, followed by a significant and sustained drop from 2034 onwards. Interestingly, the profiles in both figures are quite similar, indicating that interconnection charges and transport costs are fairly stable across each option.

Figure A.4: Comparison of average consumer prices, including interconnection charges, transport costs and energy prices ($/MWh, $2018)[327]

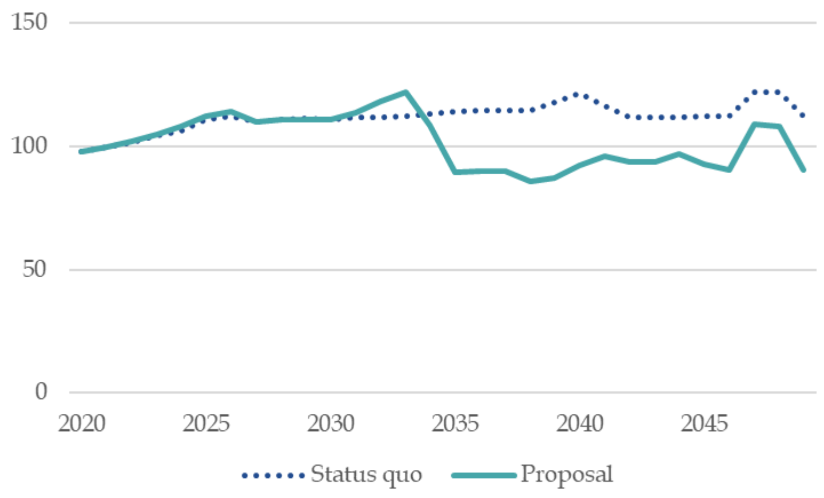
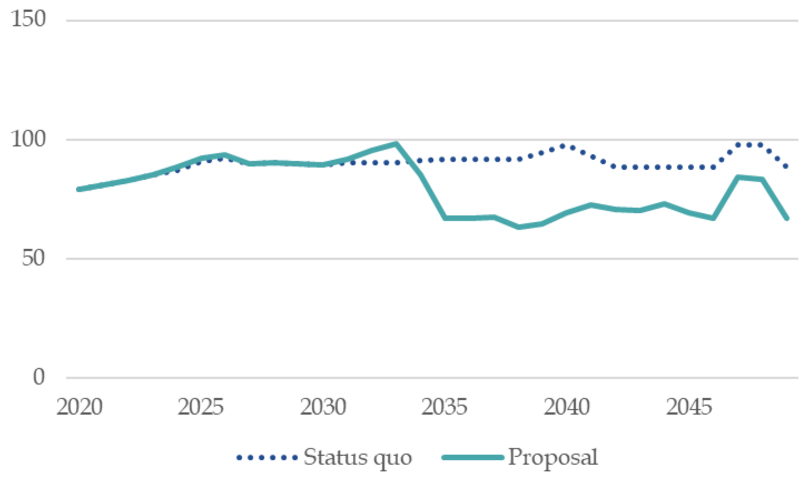


Figure A.5: Comparison of average generation prices ($/MWh, $2018)[328]



[327] Data are sourced from the 'AOB.csv' and 'RCPD.csv' files for the 'All_major_capex' scenario. Average prices were calculated for a given year by multiplying prices for each backbone node and time period by the corresponding consumption quantities and dividing by total consumption.

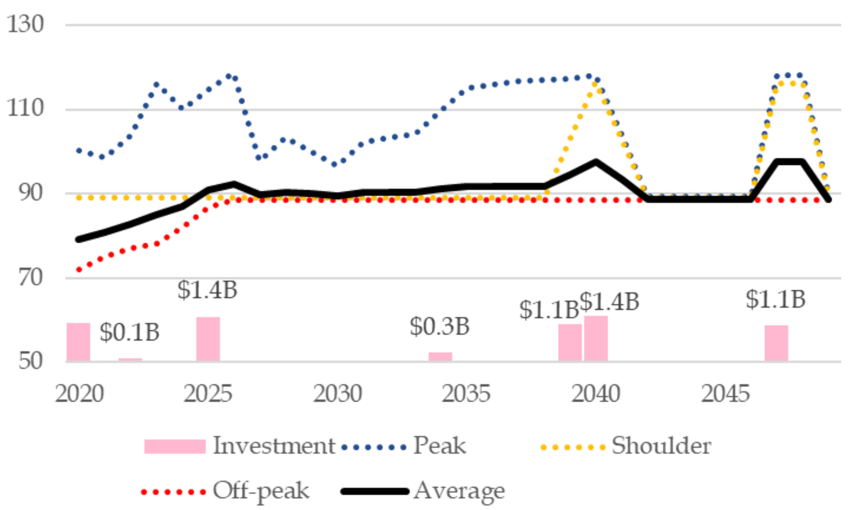
[328] *Ibid.*

Looking at prices a little more closely, Figure A.6 and Figure A.7 split out the average generation prices for the status quo and the proposal respectively into the peak, shoulder and off-peak time periods,[329] with generation investment shown underneath. The profile for the status quo is fascinating for several reasons:

- there are some blips in price in 2040 and 2047–2048 that appear to correspond to spikes in generation investment;
- there is almost perfect alignment of prices from 2042 to 2046; and
- there is an obvious break in the profile of peak prices from 2041 onwards.

There is no obvious explanation for these observations. It is not at all clear what would be driving such an unusual profile of generation prices.[330] It certainly does not comport with anything that one would typically expect to see, which casts substantial doubt over the efficacy of the modelling.

Figure A.6: Breakdown of generation prices - status quo ($/MWh, $2018)[331]



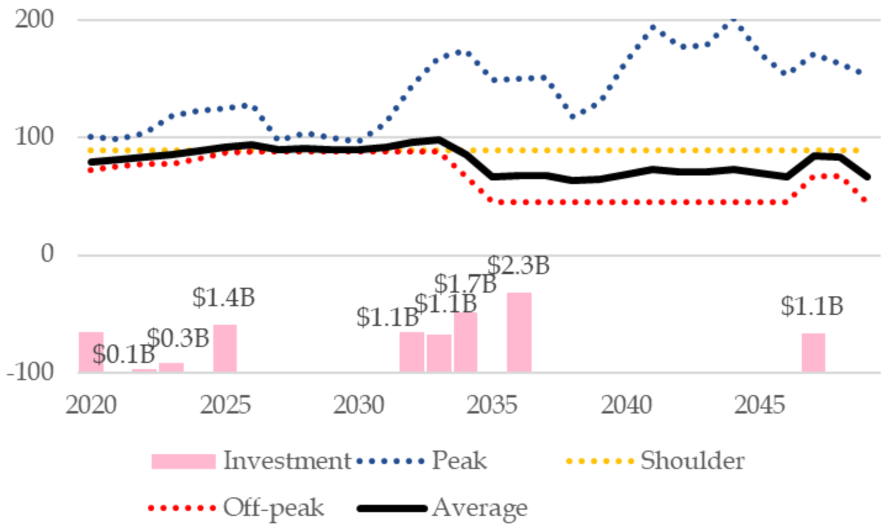
The profile for the proposal is a little more intuitive. Peak prices start increasing from 2030 onwards, apparently in response to the increase in demand. This prompts the significant generation investment over 2033 to 2035 and again in 2037, which in turn drives significant reduction in all prices from 2034 onwards. Unlike with the status quo profile, the prices for the three time periods do not converge.

329 Note that the vertical axes have been truncated to make it easier to view the differences, so care should be taken when comparing the two figures with each other.

330 As we explore in section B.2.3, the significant investment in grid-connected batteries *may* be the cause. If those batteries were used primarily to arbitrage between time periods, this could lead to an alignment in prices across those periods. But it seems implausible that batteries could lead to complete alignment. We know of no other empirical predictions to that end.

331 Data are sourced from the 'RCPD.csv' file for the 'All_major_capex' scenario. Average prices were calculated for a given year and time period by multiplying prices for each backbone node by the corresponding consumption quantities and then dividing the result by total consumption for that time period and year.

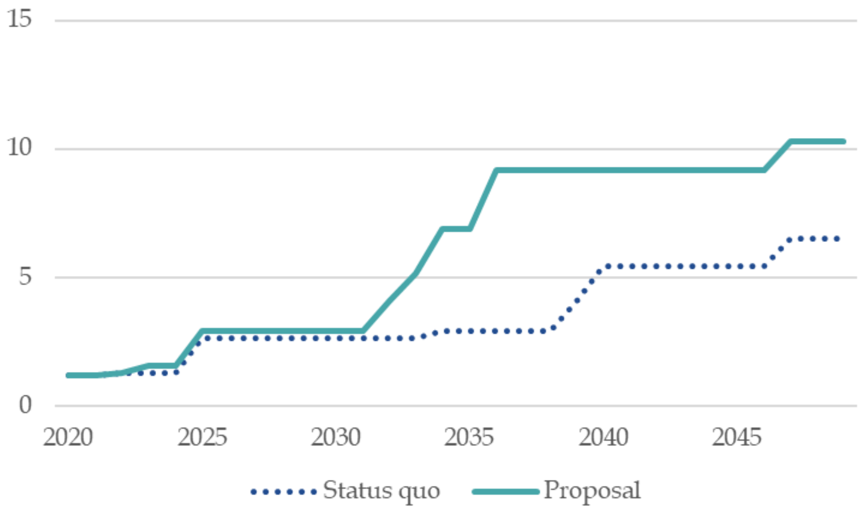
Figure A.7: Breakdown of generation prices - proposal ($/MWh, $2018)[332]



A.2.2.5 *Projected investment*

Figure A.8 and Figure A.9 compare the cumulative investment in grid-connected generation and batteries, respectively. In the first figure, the proposal leads to $1.9b *more* in grid-connected generation than the status quo. In the second figure, the proposal leads to $202m *less* in grid-scale batteries, which is likely to be at least partly attributable to the assumed significant increase in generation.

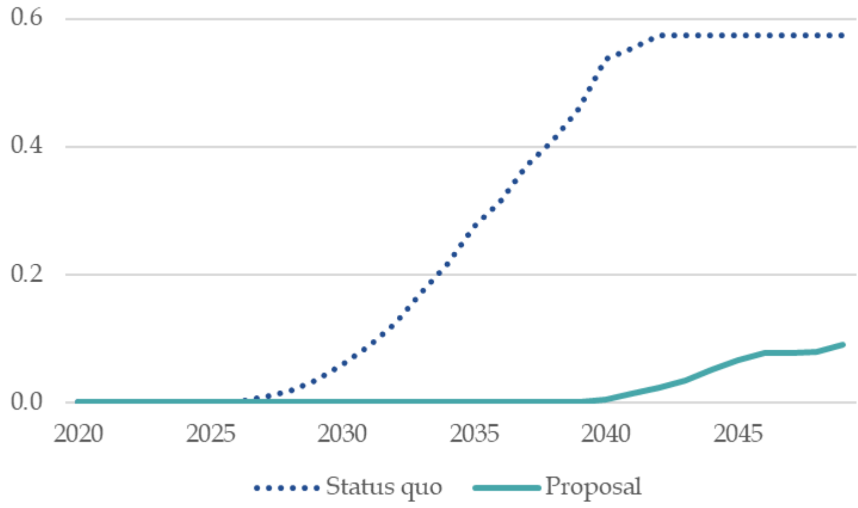
Figure A.8: Cumulative investment in grid-connected generation ($billion, $2018)[333]



332 Data are sourced from the 'AOB.csv' file for the 'All_major_capex' scenario. Average prices were calculated for a given year and time period by multiplying prices for each backbone node by the corresponding consumption quantities and then dividing the result by total consumption for that time period and year.

333 Data are sourced from the 'generation_investment.csv' file for the 'All_major_capex' scenario.

Figure A.9: Cumulative investment in grid-scale batteries ($billion, $2018)[334]



A.3 Top down analysis

Top-down analysis is used to estimate the smaller and more bespoke costs and benefits. This section explains briefly how this was done.

A.3.1 Investment efficiency modelling

The CBA uses Monte Carlo analysis to simulate the potential benefits from efficient investment by generators and large loads. These benefits manifest in the form of reduced or deferred investment in the transmission network.

This analysis assumes that generators and large loads (i.e., transmission consumers) would respond to expected *future* BB charges by reducing or shifting their generation and consumption to areas where the transmission network has more capacity – and so a reduced need for investment. In other words, generators and consumers are assumed to respond to 'implicit shadow prices' that reflect the expected future consequences of current decisions.

However, just as with the OGW CBA, those shadow-prices do not reflect the price signals that customers would actually be facing under the BB charge. They are again based on a simplistic measure of LRMC[335] which, as we explained in section 3.4.1, is

334 Data are sourced from the 'total_dg.csv' file for the 'All_major_capex' scenario.

335 Specifically, the Authority assumes that increases in peak demand give rise to additional transmission investment. It calculates this rate of incremental investment expenditure each year as: forecast incremental network expenditure in that year *divided by* the change in peak demand between the previous year and that year. This approach gives rise to estimates of expenditure per additional MW that vary from $178,822 (in 2026) to $2,895,453 (in 2032) , taken from the example calculation in the 'Efficient investment' sheet of the 'Investment efficiencies model.xlsx' file. These are somewhat like pseudo LRMC estimates, calculated using only a year of expenditure and demand growth. These are the 'shadow price signals' to which customers are assumed to respond. They bear no resemblance at all to the *actual* price signals that would be provided by a BB charge.

wrong. Instead, the implicit price signals that each customer would face under the BB charge would be:

- impossible for all but the most sophisticated of customers to discern, even assuming they were included to respond to them; and
- *not* cost-reflective, i.e., BB shadow price signals would only resemble LRMC by sheer coincidence.

In other words, although the Authority has attempted to model something resembling its own proposal by including shadow prices of a sort, it has failed. Under the Authority's proposal, customers would face bespoke shadow price signals that reflected the benefits that they expected to receive from an investment. That is certainly *not* what the Authority has modelled and, indeed, it is not obvious how it *could* be quantified.

Setting that flaw aside, an externality framework is then used to relate (via equations) the estimated cost of increased load or generation in a given area into shadow prices that prompt consumer and generator responses, leading to corresponding reductions in transmission investment. The programming language Python is used to model those relationships and simulate the assumed variables that are needed to populate the equations.

Benefits from more efficient load (or demand) and generation investment decisions are measured separately. So too are the costs of load or generation not locating in regions with recent investment in transmission capacity, which would serve to push up current BB charges for any transmission users located there.

A.3.2 Scrutiny modelling

The CBA estimates how much transmission investment would decrease if interested stakeholders apply greater scrutiny to investment decisions. This reduction is estimated by multiplying the transmission investment that Transpower is forecast to undertake over the 2022 to 2049 period by an assumed productivity gain of either 4%, 2%, 1% or 0%, depending on the category of expenditure. The assumed productivity gains are derived from a single observation.

Namely, the Authority notes that the Commission reduced Transpower's proposed enhancement and development (E&D) base capex projects allowance by 4.4% between the draft and final determinations for the second regulatory control period (RCPD2). The four efficiency factors are extrapolated from this single data point which, as we explain below, in addition to being irrelevant, is clearly the wrong number. The analysis is undertaken in the '*Investment efficiencies*' spreadsheet.

A.3.3 Durability modelling

The CBA also uses Monte Carlo analysis to simulate the benefits to investors from reduced policy uncertainty. A key assumption is that implementing the TPM would reduce the frequency of 'uncertainty' events.

The analysis uses a simplified static equilibrium framework to model the impact of uncertainty on supply and demand. Monte Carlo simulation is used to 'shock' that equilibrium with a reduction in uncertainty to see how total surplus changes (i.e., the sum of consumer and producer surplus). The analysis was also undertaken using Python computer code. The modelling appears, at first blush, to be extremely technical and sophisticated.

However, the results are influenced largely by a small number of critical assumptions. For example, the Authority has had to determine what the 'shock' would look like (including whether it is positive or negative) and the benchmark level of uncertainty. As we explain subsequently, these two assumptions – that cannot be tested or verified in any way – are ultimately driving the results.

A.3.4 Development, implementation and operation costs

Finally, the CBA includes estimated costs of developing, implementing and operating the proposed TPM. These are based largely on estimates submitted by Transpower to the Authority in 2016 in relation to a different proposal. Some adjustments are made to those estimates, including to add costs expected to be incurred by the Authority and stakeholders.

Perhaps unsurprisingly, it is this component of the CBA that appears the most credible – primarily because there is a reasonable empirical basis for most of the constituent elements. Clearly, if the Authority's proposal is adopted, parties would incur design, implementation and development costs. That is beyond dispute. The only question is how much those costs would be – not whether they would arise in the first place.

Appendix B Key concerns with the CBA

Every aspect of the CBA is deeply flawed in numerous respects. Generally speaking, the problems with the modelling fall into four categories:

- there are many foundational analytical shortcomings, including the erroneous inclusion of wealth transfers and the failure to account for obvious substantial additional relevant costs;
- there are several prominent instances in which assumptions have been made that do not reflect the way the electricity market actually works or how the actors within it make decisions;
- there is a multitude of inconsistencies and internal contradictions within the modelling that introduce bias, e.g., avoided investments in batteries are counted as a benefit, but new investment in generation is not counted as a cost; and
- various aspects of the way in which the modelling has been performed introduce further intrinsic uncertainties (including the conspicuously long timeframe that has been employed) and additional errors.

We explore each of these in turn in this appendix. As we shall see, the upshot is that the CBA cannot provide any meaningful insight into the merits of the proposal.

B.1 Foundational analytical problems

The CBA contains several foundational analytical shortcomings. The most prominent problems include the following:

- neither the grid use model (which generates 96% of the estimated net benefits) nor the top-down modelling reflect the methodology that the Authority has proposed; for example:
  - the grid use modelling does not include the implicit forward-looking 'shadow' price signals that the Authority says would be supplied by the proposed BB charges; and
  - the 'top-down modelling' *does* include forward-looking price signals but, they are *wrong*, i.e., the model mistakenly assumes that consumers would face price signals that reflected a rudimentary measure of the LRMC of transmission, which is incorrect (see section 3.4.1).[336]
- the benefit estimate produced by the grid use model for the Authority's proposal could be achieved using virtually *any* methodology comprised solely of fixed charges, i.e., those fixed charges would not need to be based on estimated benefits – any number of alternatives could be used;

[336] This is exactly the same mistake that Oakley Greenwood made in its CBA. It assumed – wrongly – that shadow prices would reflect a measure of the regional LRMC of transmission. However, as we explained previously, BB charges *would not be cost-reflective*. The BB shadow price signals that individual customers would face would not be equal to LRMC. Indeed, if they would, then why would the Authority not simply have recommended an LRMC charge?

- other reasonable alternatives (e.g., LRMC based charges) are not considered in the CBA – which creates a bias in favour of the proposed methodology;
- the modelling mistakenly includes $2.3b in wealth transfers that are neither benefits to New Zealand's economy nor improvements to the overall efficiency of the electricity industry – these are simply payments from one group of consumers to another, i.e., this is not 'new wealth';[337]
- the modelling ignores the significant cost of additional investment in generation ($1.9b) and distribution networks (conservatively ~$27–$81m) that would be needed to support the noticeable increase in peak demand that the Authority forecasts would occur if its proposal is adopted, as well as environmental costs;
- optimism bias appears to have led to costs and benefits being included and modelled in ways that support the proposed methodology without appropriate theoretical and/or empirical foundations; and
- many aspects of the modelling – especially of grid use benefits – are needlessly complicated, which makes it impossible to comprehend for all but a select audience and masks fundamental shortcomings with it.

Many of these problems are sufficiently serious in their own right to cast substantial doubt over the CBA results. In culmination – and when combined with the other shortcomings identified subsequently – they highlight why the CBA is wholly unfit for its intended purpose.

B.1.1 The Authority has not modelled its own proposal

The Authority explains that a key function of its proposed BB charge is to provide an implicit forward-looking 'shadow price' signal. The idea is that customers would consider the impacts of their consumption and investment decisions on future transmission costs. For instance, the Authority notes that:[338]

> *'…transmission customers that are required to pay a benefit-based charge for a future grid investment will have an incentive to take transmission costs into account in making decisions about their own investments and use of the grid.'*

It later elaborates that:[339]

> *'…charging users…for an investment after it is made is necessary to ensure that the efficiency benefits relating to new investments described above are realised. Over time, grid users' behaviour before a grid investment is made will likely adjust to reflect the charges they will face for the investment when it is made. If we do not charge the beneficiaries of the investments the full cost of the investment when it is made, then the behaviour of grid users before a particular investment is made will reflect this fact. We therefore consider that the best way to encourage users to take account of the full cost of the investment before it is made*

[337] An alternative to removing the wealth transfer would be to recognise the reduced revenue earned by generators as a cost in the CBA, of $3.9b.

[338] Third Issues Paper, p.115.

[339] Third Issues Paper, p.200.

is to charge those who benefit from the investment the full cost of the investment when (after) it is made.'

However, these 'shadow prices' are nowhere to be seen in the grid use modelling and, as we explained in section A.3.1, the implicit price signals it includes in the top-down modelling are wrong.

In terms of the grid use modelling, the demand and grid-scale generation investment equations used (and reflected in the Python code) do not consider the impact that future transmission charges might have on current consumption and investment decisions. This is also evident in the charts included in the Issues Paper (e.g., Figures 6 and 7), which clearly do not incorporate any 'shadow price' components. If the modelling did incorporate these shadow prices – which are a core feature of the proposal – then the results would inevitably differ significantly from those published by the Authority.

Without further analysis, it is hard to say for sure what impact shadow prices would have on the CBA net benefit. However, given all of the problems with the underlying theory, it is safe to assume that the impact would be negative. As we explained earlier in this report, it is unrealistic to expect customers to be able to predict – and respond to – future BB charges, which the Authority has acknowledged in other contexts.[340] Moreover, even if customers could anticipate their future BB charges, those prices would be sending *the wrong signals.*

BB price signals are not cost-reflective and, as we explained in section 4, they would consequently cause load and generation customers to respond by making *inefficient* consumption and investment decisions. If the Authority had modelled these impacts accurately (which would be very challenging, given the bespoke nature of the BB shadow prices that each customer would face) then it is highly unlikely – perhaps even implausible – that it would have obtained a net benefit.

These problems have also affected the top-down modelling – namely, the $43m estimated benefit from more efficient investment by load and generation. As we explained in section A.3.1, the shadow prices that the Authority has incorporated into this analysis do not reflect the price signals that customers would actually face under the BB charge. The Authority has assumed customers would face a simplified version of an LRMC based charge, which is not accurate, since private benefits are not synonymous with long-run costs.

As it is, all that we can say for certain is that because shadow prices are a crucial element of the Authority's proposed methodology, it has not actually modelled its own proposal. This effectively renders nearly every aspect of the CBA irrelevant. As we noted earlier, this was one of the most fundamental problems with the OGW CBA that the Authority was forced to abandon. That analysis assumed – wrongly – that BB shadow-price signals would resemble the regional LRMC of transmission. Regrettably, history has repeated itself in crucial aspects of this latest CBA.

340 *See for example:* Electricity Authority, *Review of distributed generation pricing principles, Consultation Paper*, 17 May 2016, Appendix E.2-E.3.

B.1.2 The model would produce the same answer for multiple options

The grid use model not only neglects to reflect the methodology that the Authority has actually suggested, it would also predict effectively the same outcome for *any number* of alternatives. Provided that an approach is comprised *solely of fixed charges*, the grid use model would produce effectively the same $2.6b benefit. There is no need for those fixed charges to be based on an estimate of private benefits. For example, the following methodologies would perform equally well:

- replacing the RCPD and HVDC charges with a single non-distortionary broad-based tax comprising only fixed charges, i.e., something akin to the proposed residual charge; or
- as implausible as it may seem, replacing the RCPD and HVDC charges with a purely random allocation of fixed charges, i.e., where transmission customers' annual fixed dollar sums were drawn out of a hat.

In other words, even taking the grid use model as given with its many flaws, the benefit estimate that it produces is *not* uniquely attributable to the Authority's proposal. What the model has *really* estimated is a benefit (albeit an erroneous one) that could be obtained by replacing the RCPD and HVDC charges with almost any variant of fixed charging. This is not symptomatic of robust modelling – particularly given the absurdity of the methodology described in the second dot point.

B.1.3 Other alternatives ignored

The CBA considers three alternative options; namely, the status quo, the Authority's proposal and an alternative option. It did not consider other options, including those proposed by stakeholders previously, such as LRMC pricing options, or Transpower's 'simplified-staged alternative'. The Authority could well argue that it has undertaken a qualitative analysis of a number of options – including LRMC pricing options. However, that is not a satisfactory response, because:

- as we explained in section 2.3.1, its qualitative assessments of those alternative options have not been balanced, i.e., characteristics that are shared by the Authority's own proposal are often deemed to be irreparable flaws when seen in another methodology; and
- in the case of LRMC pricing options, the Authority's own LRMC paper (which was sent to Professor Hogan for comment) concluded that further analysis of the approach was needed – including further testing via a CBA.[341]

The Authority might also point out that it did not want to over-complicate the analysis or add further cost and effort. But that would not be a very persuasive response either. The Authority would be the first to concede that the previous CBA performed by Oakley Greenwood was very poor – in part due to its unduly narrow focus. It has had more than two years to put that unfortunate experience behind it

341 Electricity Authority, *Nodal pricing and LRMC charging*, p.2.

by performing a robust, comprehensive analysis. This makes it all the more difficult to understand why more options were not examined.

The absence of additional methodologies serves to inflate artificially the perceived attractiveness of the Authority's proposal.[342] If other reasonable alternatives were included, then they may well have yielded higher net benefits using the Authority's CBA methodology. For example, as we have explained throughout this report, if there are potential benefits on offer from more efficient grid use (e.g., because the RCPD signal is currently too strong), they could be obtained from other more orthodox approaches – like an LRMC-based charge. They are not uniquely attributable to the Authority's proposal.

B.1.4 Wealth transfers included

The Authority has made *two* errors relating to wealth transfers. First, it treats wealth transfers from generators to final consumers (resulting from lower wholesale prices) as benefits, when they should have been removed. Second, it adds back a wealth transfer from consumers to generators (resulting from a reallocation of interconnection charges) as a further benefit, when there was no need for such an adjustment (because it was not treated as a cost anywhere else in the CBA).

B.1.4.1 *Leaving in wealth transfers from generators to final consumers when they should be removed*

A key shortcoming of the Authority's analysis is that it uses changes in consumer surplus, rather than deadweight loss/allocative efficiency, to measure more efficient grid use. By doing so, the Authority mistakenly includes wealth transfers from generators to final consumers in its net benefit estimate. Such transfers are *not* 'gains' to the New Zealand economy. Indeed, the Authority itself has said that it 'does not take wealth transfers into account in making decisions.'[343] Including them in the CBA serves to inflate the estimated net benefit – considerably in this case.

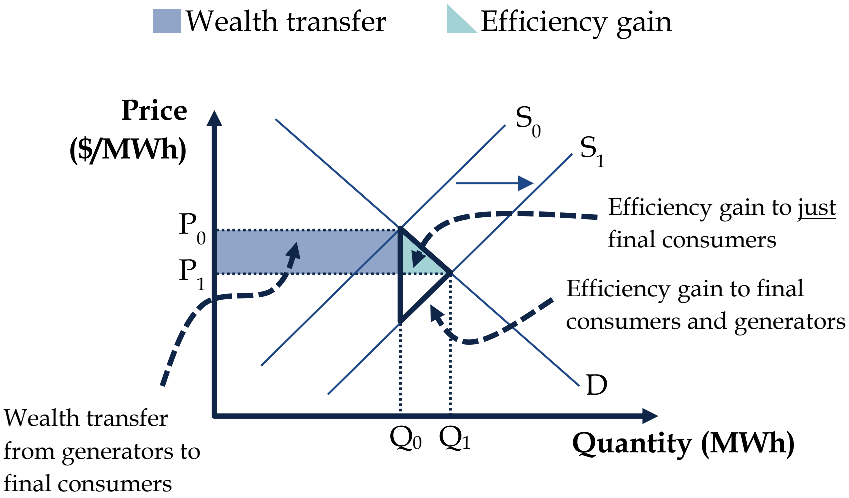
Figure B.1 helps highlight this problem. The equation at the top is a simplified version of the consumer surplus calculation used by the Authority to determine its central CBA net benefit estimate (equation 10 in the Technical Paper). The chart beneath it is a stylised representation of what happens to consumer surplus when there is a movement *along* the demand curve (i.e., an increase in quantity demanded, following an outward shift of the supply curve).

342 This is rather like scratching a horse at the races – the odds of the remaining horses winning go up.

343 Third Issue Paper, p.31.

Figure B.1: Measuring consumer surplus with a shift along the demand curve

$$\Delta CS = \underbrace{-Q_0 \times (P_1 - P_0)}_{\text{Wealth transfer}} - \underbrace{0.5 \times (Q_1 - Q_0) \times (P_1 - P_0)}_{\text{Efficiency gain}}$$



In the figure, the supply curve shifts outwards, which leads to an increase in the quantities supplied and demanded and a reduction in the market-clearing price. There are two effects from the reduced price:

- some surplus is shifted from generators to final consumers, i.e., a transfer of 'generator surplus[344]' to 'final consumer surplus' (see the blue rectangle); and
- some new consumer surplus is generated that is not taken from anyone else, i.e., a reduction in 'deadweight loss' (represented by the green triangle).[345]

The former is a bare transfer of wealth. It arises because of the reduced prices that final consumers pay for electricity that they would have consumed anyway at the higher price. It comes entirely at the expense of generators who receive those now lower prices.[346] This does not produce any *additional welfare* that did not previously exist – it is a bare transfer of current wealth and is consequently welfare neutral. It is for that reason that the Authority has said it does not account for transfers in its decision making (despite doing precisely that in its CBA).

In contrast, the reduction in deadweight loss (represented by the green triangle) clearly *is* a benefit. At the lower price, there is additional demand for electricity that *did not happen* at the previous, higher price. Provided that demand can be served a price that generators are willing to accept and that final consumers are willing to

344 Note that 'generator surplus' is not 'producer surplus' in the traditional sense, since generators are also consumers of transmission services.

345 If total welfare gains were being measured, then the entire area of the bolded dark triangle outline would be captured.

346 In truth, that rectangle is the *net* wealth transfer. As the Authority itself recognises, the grid use model predicts some transfer of interconnection charges from generators to final consumers if its proposal is adopted, which are effectively netted out in that rectangle. This arises because the prices used to apply equation 10 include generation prices, transportation costs *and* interconnection charges, but exclude retail margins or costs.

pay *new wealth* can be generated. In other words, it is possible to make some people better off without making others worse off.

In other words, changes in consumer surplus entail both allocative efficiency improvements ('triangles') and bare wealth transfers ('rectangles'). Because triangles tend to be smaller than rectangles (at least in this context), the transfer component will often outweigh the reduction in deadweight loss – typically by a comfortable margin. Regrettably, the Authority has failed to make this basic but crucial distinction in its grid use model.

Instead, the equation the Authority has employed measures the *total change* in consumer surplus which, as we have seen, will include bare wealth transfers. By failing to differentiate between these two effects, the Authority has mistakenly included the 'wealth transfers' from generators to final consumers in its estimated net benefit. This has caused it to overstate the benefits that would flow from more efficient grid use – and to a dramatic degree. However, determining the exact impact of this error on the overall benefits estimate is not straightforward.

That is because equation 10 is predicated on there being a movement *along* the demand curve. That is not actually correct. In truth, the grid use model is implying that there is a movement *of* the demand curve (e.g., a shift or tilting). That is because the demand in one time period (e.g., off-peak) is influenced by demand in another time period (e.g., peak). That being the case, a *completely different* equation is needed to measure the change in consumer surplus – not equation 10. That is a more complicated task, and not what the Authority has actually done.[347]

Nevertheless, if one takes the Authority's approach as given and assumes that it was appropriate to use equation 10 (which, in truth, it is not), then the resulting benefit (of $2.6b) clearly includes wealth transfers. The magnitude of this error can be estimated using the output files generated by the model.[348] Performing that analysis reveals that this particular wealth transfer component of the consumer surplus change accounts for around 73% or $1.9b of the $2.6b.

As we noted earlier, the Authority recognises that wealth transfers should not be counted as benefits. It has even taken steps to remove them from the analysis in

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347 If the change in total (consumer and generator) welfare were measured, it would almost certainly differ from the value estimated by the Authority. That is in part because Equation 10 does not pick up 'gaps' between curves. However, the likely extent of that difference is unclear.

348 For instance, using the raw quantities and prices from the 'CS_results.csv' spreadsheet for the 'All_major_capex' scenario, the change in consumer surplus can be split into the wealth transfer and efficiency gain components of equation 10. In Excel terms, the wealth transfer for a given year, backbone node and time period can be calculated as:

$$-MIN(Q_0,Q_1)\ x\ (P_1 - P_0) + IF(SIGN(P_1 - P) = SIGN(Q_1 - Q_0),-0.5\ x\ (P_1 - P)\ x\ (Q_1 - Q_0)).$$

The second term (within the 'IF' function) includes the green shaded triangle as a wealth transfer (positive or negative) where the price and quantity both increase or both decrease. Although such an occurrence would ordinarily indicate a movement *of* the demand curve (given that that curve is ordinarily downward sloping), for illustrative purposes it is assumed to reflect a movement *along* an upward sloping portion of the demand curve – consistent with the assumptions behind equation 10 (which cannot apply to a movement *of* the demand curve).

some instances. For example, it adds back the wealth transfer from consumers to generators related to the changes in transmission interconnection charges. The Authority describes this in the following way: [349]

> *'Under the proposal, over the modelling period, consumers end up paying higher transmission charges and generators end up paying lower charges (compared to the status quo). So amongst other things, the proposal causes a wealth transfer from consumers to generators.'*

Incidentally, as we explain in the following section, this appears to be a well-intentioned mistake. There was, in fact, no need to add this wealth transfer back into the benefits estimate, because it is not included as a cost elsewhere in the CBA, i.e., the adjustment is needless. But setting that aside, given that the Authority went to the effort to account for *this* wealth transfer – albeit erroneously – it is consequently difficult to understand why it did not endeavour to do the same when measuring the change in consumer surplus. After all, that calculation is of substantially more significance to the overall benefit estimate.

Strangely, at one point in its paper, the Authority contends that the reduction in nodal prices predicted by its grid usage model would *not* give rise to a wealth transfer from generators to final customers. It offers a curious rationale:[350]

> *'Generators would not lose out to consumers, because, in the model, the falling prices are a result of generators expanding efficiently in response to increased demand and prices that justify the expansion. The expansion benefits both generators and consumers.'*

This explanation is not credible. Lower wholesale prices cannot benefit both the customers that are paying them *and* the generators that are receiving them. It is possible that some *new* generators might be better off, i.e., because they enter and earn at least a normal economic profit.[351] However, if that new entry causes wholesale prices to fall then, by definition, all *existing* generators would be unambiguously *worse off*. Money they would have earned at the higher wholesale price would flow to end customers, resulting in a very large wealth transfer. This is precisely the scenario depicted in Figure B.1.

In other words, even before one examines the grid use modelling, it is not tenable to suggest that the scenario being depicted does not give rise to vast wealth transfers. It plainly does. This is confirmed by the modelling itself. Outputs from that modelling suggest that, under the Authority's proposal (relative to the status quo):

349 *See:* cell M1 on the 'Summary grid use model' sheet of the Electricity Authority's 'Summary costs and benefits.xlsx' spreadsheet, published on 22 July 2019.

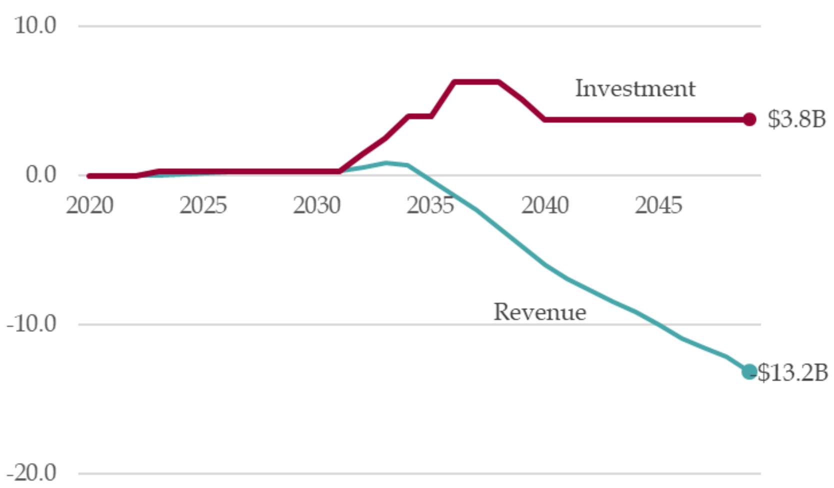
350 Third Issues Paper, p.32.

351 However, the analysis set out in the previous section suggests that even *new* generators – i.e., those that enter in response to the modelled increase in wholesale prices – would often struggle to earn a reasonable return on their new investments. That is because of the aforementioned 'generation entry decision rule' which assumes that generators would invest without paying any attention to the potential impacts upon future spot prices.

- generation investment would *increase* by some $3.8b in total over the 2020 to 2049 period;[352] while
- generation revenue (net of interconnection charges) would *reduce* by $13.2b.

The model is therefore suggesting that generators as a group would invest an awful lot, but not receive much in return – a problem that we return to in section B.2.2. Collectively, in NPV terms, generators are worse off to the tune of $5.8b under the proposal – with reductions in revenue accounting for $3.9b of that sum. A sizeable fraction of that revenue drop (depicted in Figure B.2 below) would undoubtedly comprise the estimated $1.9b in wealth transfers from generators to final consumers described above.[353]

Figure B.2: Comparison of cumulative generator revenues and investment costs differences (proposal less status quo) ($billion, $2018)[354]



Another way of looking at this is to compare the wealth transfer to the change in generator revenue. We undertake this analysis in Figure B.3. As expected, the two curves are almost perfect mirror-images of each other. Higher wealth transfers from

352 Generation investment is forecast to increase by $3.8b in total and by $1.9b in NPV terms.

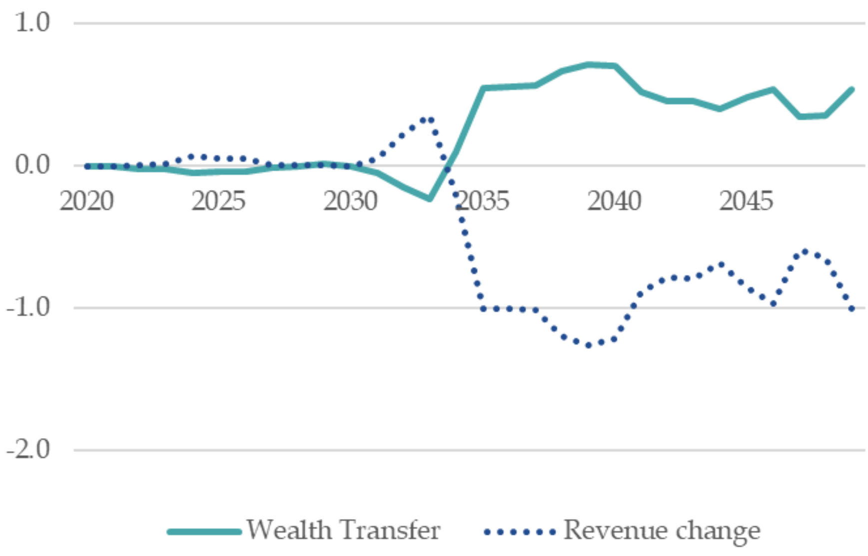
353 One response to this analysis might be that much of the $2.2b change in consumer surplus reflects benefits from removing the RCPD charge and replacing it with the BB and residual charges. However, that seems highly unlikely given that:

- as the Authority points out, consumers end up paying *more* in interconnection changes – there would have been no apparent (albeit mistaken) need to add back this particular wealth transfer if that were not the case; and
- the estimated change in consumer surplus remains high even if we look at just the change in generator prices (i.e., excluding inter-connection charges and transportation costs) – for instance, the $4.4b in consumer surplus change estimated when price changes are factored in reduces to $4.1b if generation prices are used, i.e., still a very large sum.

354 Data are sourced from the 'AOB.csv', 'RCPD.CSV' and 'generation_investment.csv' files for the 'All_major_capex' scenario. Generator revenue is calculated for a given year by multiplying the quantities for each backbone node and time period by the corresponding generator price and summing these together. A net revenue value is obtained by subtracting the interconnection charges faced by generators.

generators to final consumers correspond to lower revenues to generators, and vice versa. The two curves even cross the horizontal axis at the same point.

Figure B.3: Comparison of transfer to generator revenue change ($billion, $2018)[355]



As we mentioned earlier, it is *possible* that some generators might be better off in the scenario depicted above. However, with these numbers, it is beyond dispute that most would be *far worse off* on average. As we discuss further below (section B.2.2), that is likely on account of the perverse investment decision rule used in the grid use modelling, which assumes – unrealistically – that generators ignore future prices and revenues when deciding whether to invest. In truth, much of the investment depicted in Figure B.2 *would not happen* in practice, and so the predicted increase in consumers surplus would not eventuate either.

B.1.4.2 *Adding back wealth transfers from consumers to generators when there is no need*

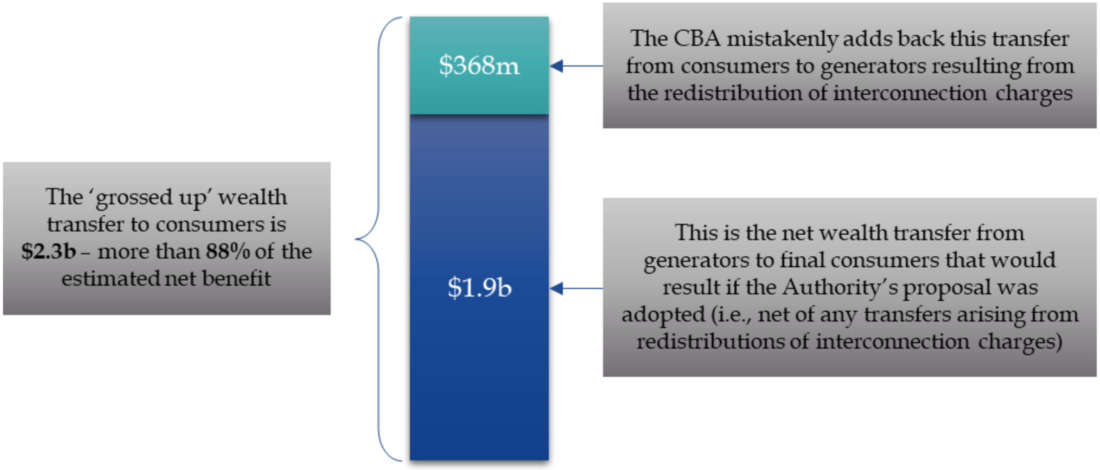
The Authority observes that the grid use model projects that consumers' share of interconnection charges would go up, while generators' share would reduce, if its proposal was implemented. This largely reflects a wealth transfer.[356] The Authority therefore assumes that it is appropriate to add back that value – $368m – because it presumably believes that it has been treated as a cost somewhere else in the CBA. In other words, it presumes that an equal-and-offsetting adjustment is needed to the 'benefits' side of the equation.

355 Data are sourced from the 'AOB.csv', 'RCPD.CSV' and 'CS_results.csv' files for the 'All_major_capex' scenario. Generator revenue is calculated for a given year by multiplying the quantities for each backbone node and time period by the corresponding generator price and summing these together. A net revenue value is obtained by subtracting the interconnection charges faced by generators.

356 However, not all of the change in interconnection charges would reflect a wealth transfer. The grid use model forecasts additional transmission investment would also be needed to meet the forecast increase in peak demand. This new investment would increase total interconnection charges for both consumers and generators, i.e., it would not be a pure reallocation.

The trouble is that the $368m is *not* treated as a cost anywhere else. None of the costs included in the CBA pick up this transfer from consumers to generators. Perhaps the Authority considers that its estimated change in the consumer surplus would be higher if there was no such wealth transfer. That may be true; but including it as a net benefit would not make sense. As we noted earlier, such a change in consumer surplus is the wrong measure precisely *because* it includes (net) wealth transfers already. Adding the interconnection wealth transfer on top of it only serves to make the problem even worse, as Figure B.4 illustrates.

Figure B.4: Grossing up the wealth transfer benefit to consumers (not to scale)

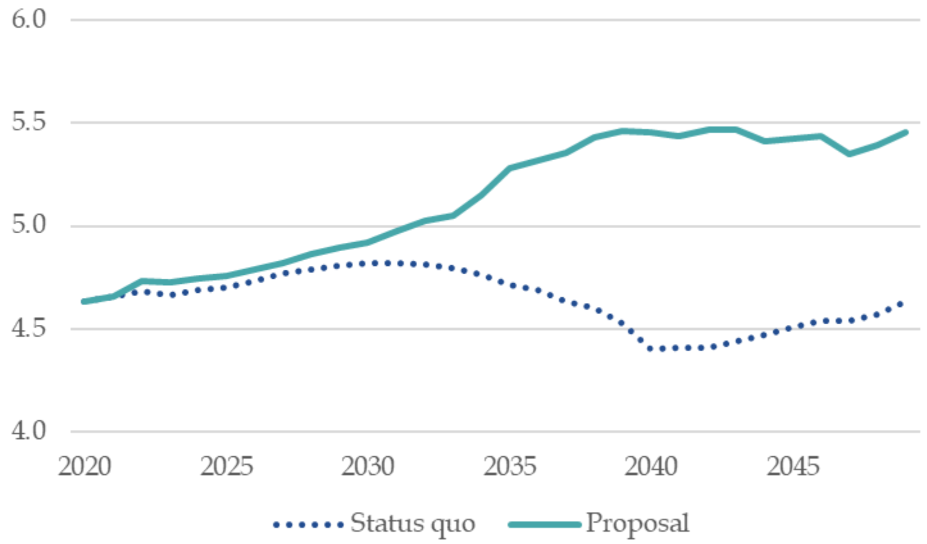


The needless adjustment serves to inflate the net benefit estimate by a further $368m. That pushes the total sum of inappropriate wealth transfers up to $2.3b, which represents 88% of the estimated benefit from more efficient grid use.

B.1.5 Consequences of higher peak demand missed

A key prediction of the grid use model is that consumption would increase significantly during peak periods under the Authority's proposal relative to the status quo. Figure B.5 illustrates this differential.

Figure B.5: Peak consumption (TWh)[357]



To manage such an increase in peak demand, additional investment would be needed in:

- Transpower's transmission network;
- electricity distribution networks; and
- grid-connected generation.

The CBA picks up the first of these as a cost – which it estimates to be $188m[358] – but ignores the other two. The CBA also ignores other costs associated with peak demand, such as any increase in carbon emissions.

B.1.5.1 *Distribution costs*

In the case of electricity distribution costs, the Authority notes that: [359]

> *'The CBA does not include any costs for distribution network investment brought forward.* ***This is because the focus of the CBA is transmission, not distribution****. Accordingly, we have not evaluated either the incremental costs or the incremental benefits associated with the distribution network.*
>
> *On the benefit side, we have valued consumption at the price paid at the grid exit point (GXP), rather than the price paid at the customer's point of connection on a local network. This approach excludes the additional consumption benefits relating to the value that consumers place on the distribution network. The Authority is aware that most distribution networks around New Zealand have spare capacity.* ***It follows that incremental distribution costs of the proposal are likely to be low, and in the Authority's view,***

357 Data are sourced from the 'AOB.csv' and 'RCPD.csv' spreadsheets for the 'All_major_capex' scenario. The vertical axis is truncated to highlight the divergence in consumption.

358 In our opinion, this additional transmission investment cost is likely to be closer to $370m, for the reasons that we set out in Appendix B.5.4.

359 Third Issues Paper, p.46.

***are likely to be exceeded by the incremental benefits associated with the distribution network**.'*

This is a very odd statement. The contention that the focus of the CBA is 'transmission' and that distribution costs can therefore be ignored is incorrect. The focus of the CBA is *not* on 'transmission' – it is on the costs and benefits that arise from a *proposed change in the TPM*. Consequential impacts on distribution networks are plainly part of that equation. Indeed, aspects of the CBA model clearly incorporate costs and benefits that are not elements of the transmission network – such as batteries, generation investments (in the top-down modelling), and so on. The Authority's statutory objective also refers to the electricity *industry*, not just sub-components of it.[360]

Distribution costs make up around 27% of consumers' bills – more than twice as much as the transmission component (10.5%).[361] Moreover, distribution network expenditure is influenced heavily by the need to manage peak demand. Put simply, increased peak demand leads to more investment and, in turn, higher consumer prices. Ignoring the impact that elevated peak period consumption would have on the distribution cost component of final customers' bills consequently undermines the usefulness of the CBA.

As a conservative indication of this potential impact, the higher peak consumption over the 2020 to 2049 period corresponds roughly to a 1,388 MW increase in ratcheted peak demand at the backbone node level.[362] Assuming that the LRMC of distribution network investment is between \$50–\$150/kW,[363] this would correspond to around \$27m to \$81m in additional expenditure over the period. This is a very significant amount given the size of some of the other costs and benefits that have been included in the CBA.

We note that the Authority has claimed that any such distribution costs would be 'more than offset' by incremental benefits. However, it is not at all obvious what benefits the distribution networks themselves would obtain, if any. Moreover, the benefits to consumers (e.g., from increased consumption during peak periods) are already factored into the CBA (i.e., they are wrapped up in the \$2.6b estimate). The

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360 *See: Electricity Industry Act 2010*, section 15.

361 See, for instance, Electricity Authority, 2018, *Electricity in New Zealand*, p.13.

362 This is calculated using the peak period quantity forecasts in the 'AOB.csv' and 'RCPD.csv' spreadsheets for each year and backbone node, converting them to an average MWh per hour (by dividing them by the 800 hours of peak period per year, or 1,600 30-minute trading periods). This simplification is conservative because, in practice, peak demand is not constant across the peak period, and is likely to be higher. Using peak 'observed' demand, ratcheted demand for a given year is calculated as the maximum observed demand for all years up to and including that year. If there is a drop in observed demand, then ratcheted demand does not change from the prior year. Ratcheted demand is used because it drives network investment.

363 See, for instance, Orion, 22 February 2019, *Methodology for delivering our delivery prices (from 1 April 2019)*, p.55, which includes an LRMC estimate of \$107/kVA (or ~\$86/kW assuming a power factor of 0.8). Various Australian electricity distributors report LRMC estimates of \$56/kW to \$119/kW for residential customers; *see for instance*: Jemena Electricity Networks, 20 September 2017, *Tariff Structure Statement 2016*, p.E-7; and Ausgrid, April 2019, *Tariff Structure Statement*, p.64. At an exchange rate of NZ\$1.06 per AU\$1, this equates to a range of \$60–\$126/kW.

Authority provides no indication at all as to what those benefits might entail. In our opinion, the most likely reason for this is that they do not exist.

B.1.5.2 *Generation costs*

In the case of the additional generation investment that is forecast to be required to meet the additional demand, the Authority recognises that this would give rise to both costs and benefits:[364]

> *'Additional investment in generation has both costs and benefits. The costs consist of the additional capital and operating expenditure for the additional generation plant. The benefits relate to the resulting reduction in wholesale electricity prices due to the increase in the supply of electricity into the wholesale market. That is, while the proposal is, in the shorter term, likely to cause an increase in energy costs, these are offset to some extent by increased generation investment.'*

The Authority's grid use modelling predicts that an additional $1.9b of generation investment would occur if its proposal went ahead.[365] Clearly, that is a very large sum. However, its model includes only the benefits of that investment, not the costs.[366] The Authority offers the following rationale for that approach:[367]

> *'The CBA does not include any costs for generation investment brought forward. This is because the generation sector is assumed to be competitive, so any generation investment that occurs as a result of the proposal is assumed to be efficient investment.'*

This explanation is highly unsatisfactory. Even if the wholesale market is effectively competitive, it does not follow that every investment decision made by generators is 'efficient'. Generators respond to the price signals that they are given. If the TPM supplies them with the 'wrong' signals, then the result could be inefficient investment outcomes. Indeed, the Authority has spent the last seven years explaining why, in its opinion, the current TPM does *not* produce efficient generation investment outcomes.

What the Authority is *really* saying here is that the additional generation expenditure can be disregarded *in this instance*, because it would be happening in response to *its preferred proposal*. That $1.9b in additional expenditure can therefore be *presumed* to be efficient and safely omitted from the CBA. The circularity in this logic should be self-evident: the analysis starts by assuming that the methodology being examined is efficient and then characterises everything that flows from it.

This is no way to perform a CBA. It involves making an assumption about the proposal – i.e., that it is efficient – that the analysis is *supposed to be testing*. Put another way, the modelling has, in effect, commenced by 'first assuming the

364 Third Issues Paper, pp.37–38.

365 This is calculated by comparing the investment values reported in the 'generation_investment.csv' spreadsheet for the 'All_major_capex' scenario.

366 Although the Authority attempts to discount these benefits by averaging consumer surplus changes with and without energy price effects, it nevertheless includes some benefits.

367 Third Issues Paper, p.47.

answer'. This introduces a clear bias into the CBA. The model should be including *all* the additional investments costs that would flow from the proposal – not just picking and choosing some and not others, based on a pre-conceived notion of which are 'efficient'.

In any case, even if the additional generation *would be* efficient (which seems highly unlikely[368]), it *still comes at a cost* that should be included in the analysis. The fundamental idea of the CBA is to test whether those costs are outweighed by the benefits that are estimated to result, i.e., to measure *both* – not to include one and disregard the other. At the moment, the CBA is manifestly unsound, because it is:

- measuring the supposed benefits of the new investment in generation including, for example:
  - the increase in consumer surplus arising from the lower estimated wholesale prices (most of which is a bare wealth transfer); and
  - the avoided costs of investments in batteries and DER; but
- *not* counting the cost of the investment that is needed to give rise to those benefits, i.e., the $1.9b in additional generation.

Incidentally, in our opinion it is highly unlikely that the $1.9b in new generation investment *could* reasonably be characterised as 'efficient'. In fact, it would be highly unlikely to transpire, in practice. As we explain in more detail in section B.2.2, it is hard to imagine that an influx of generation would occur if the result of that investment was a large drop in the wholesale price *and* generator revenues. Significant investment coupled with significant revenue reductions is not a typical hallmark of efficient investment. In any case, whether that investment is efficient or inefficient is ultimately irrelevant. Either way *it is a cost* and should consequently be included in the CBA.

B.1.5.3 *Carbon emissions*

In terms of **carbon emissions**, there is growing concern about the emissions that are produced during peak periods. There has also been increasing recognition of the gains that could be made from reducing peak consumption. For example, the Energy Efficiency & Conservation Authority noted recently that:[369]

> *Reducing electricity demand at peak times is again shown to be a key opportunity for New Zealand to limit the need for more electricity infrastructure spending, and reduce emissions.*
>
> *A [Concept Consulting] report commissioned by the Energy Efficiency and Conservation Authority (EECA) shows cutting peak demand on winter evenings would have the biggest impact, as this eases pressure on electricity lines networks and expensive, carbon-intensive peaking generation.*

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368 In our opinion it is highly unlikely that the $1.9b in new generation investment *could* reasonably be characterised as 'efficient'. In fact, it would be highly unlikely to transpire, in practice, for the reasons we set out in section B.2.2

369 Energy Efficiency & Conservation Authority, 29 March 2018, *Big benefits from reducing peak energy use*. Available: here.

The Authority explicitly ignores 'health or environmental policy objectives and outcomes' in its CBA.[370] However, that does not make them any less important to the New Zealand economy or to electricity consumers. In our opinion, those costs *should* be considered when assessing what changes should be made – if any – to the TPM. Indeed, the environmental costs of carbon emissions are just as important as the costs of investment in distribution networks and in generation.

B.1.6 Risk of bias evident

When performing a CBA it is important to be mindful of 'optimism bias'. This manifests primarily when 'favourable estimates of net benefits are presented as the most likely or mean estimates'.[371] The Authority acknowledges this potential pitfall in its Technical Paper.[372] This problem may occur, for example, when a CBA has been developed (intentionally or not) to *support* a given proposal rather than test its merits. The party proposing that particular reform may:

- focus on the benefits that it *wants* to believe will arise and overlook costs that it hopes will not; and
- inadvertently overestimate the benefits for a given category, while systematically underestimating costs.

The Authority attempts to deal with this potential source of cognitive bias by adopting what it considers to be 'conservative' approaches or assumptions at various stages in the analysis. Some examples include:

- allocating major transmission investments in proportion to the benefits expected for each transmission customer; [373]
- discounting some of the welfare effects obtained using the compensating variation measure for mass market consumers in the early years of the proposal;[374]
- ignoring benefits from more efficient investment by mass-market consumers (e.g., in hot water cylinders or gas-heated hot water, wood-fired heaters, generators or small-scale batteries); [375]
- focussing only on inter-regional transmission benefits, and not *intra*-regional (i.e., within region) transmission benefits;[376] and

370 Technical Paper, p.9.

371 See, for instance: New Zealand Treasury, July 2015, *Guide to Social Cost Benefit Analysis*, p. 31.

372 See, for instance: Electricity Authority, 23 July 2019, *CBA approach, methods and assumptions: TPM issues paper 2019, Technical paper*, p.94.

373 Third Issues Paper, pp.29–30.

374 Third Issues Paper, p.36.

375 Third Issues Paper, p.39.

376 Third Issues Paper, p.41.

- supposedly overestimating the costs of developing, implementing and operating the proposed TPM.[377]

Unfortunately, there are many other potential examples of optimism bias throughout the modelling that, collectively, have a far more substantial impact on the overall outcome than the factors listed above. For instance, the CBA:

- does not account for the 'shadow price' signals that the proposed BB charge would deliver – these prices are either ignored (in the case of the grid use model) or applied incorrectly (in the case of the 'top-down' modelling);
- includes as its largest category of benefits a change in consumer surplus that is largely a wealth transfer from generators to final consumers;
- excludes the $1.9b forecast increase in grid-connected generation investment;
- excludes the additional investment in distribution networks that would be needed to meet the projected increase in peak demand; and
- adopts a decision rule for grid-connected generation investment that leads to clearly counterintuitive outcomes, e.g., the model implies that:
  - an increase in electricity demand would lead to a large reduction in wholesale prices, which does not follow as a matter of economics, and
  - an increase in generation investment would result in a large reduction in generation revenues, which is similarly difficult to understand.

In other words, despite the conscious efforts of the Authority to avoid optimism bias, there are numerous clear examples where its analysis appears to have been affected by this problem. As we indicated above, that bias may be largely unconscious but, nevertheless, it has served to undermine the results of the analysis.

B.1.7 Risk of over-complication evident

The CBA and the accompanying Technical Paper are extremely complicated. That in itself is not necessarily a problem. After all, the electricity supply chain is complex and any model of it will inevitably involve lots of moving parts. However, serious problems can arise where a modelling exercise involves layer upon layer of inputs and assumptions – all of which are open to interpretation and debate. Taken one-by-one, the significance of each assumption may seem trivial but, when they are all added together, substantial difficulties can emerge.

To use a simple example, if a model includes 1,000 assumption and every one of them is out by 1%, the results can very quickly become unreliable. That is why it is crucial to assess any outputs by stepping back, looking at the bigger picture and asking: "do these results make sense?" There is an obvious risk of 'missing the forest for the trees' with a model as complex as the Authority's (which, in fact, is a collection of several models). For example, the modelling includes:

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377 Technical Paper, p.94.

- 29 algebraic equations that underpin the grid use model (and 50 formal equations across all of the assessment tools used)[378];
- more than 500 spreadsheets (and csv files); and
- more than 10,000 lines of Python and R computer code (some of which are repeated) that are used to help give effect to the 50 equations.

The modelling draws from reasonable data sources in some places (e.g., Statistics New Zealand and Transpower forecasts, or historical energy market data). However, it also relies on:

- parameter estimates that are not statistically reliable (e.g., the elasticities in the grid use model have been calculated using parameter inputs that are not statistically different from zero, which is clearly problematic); and
- assumptions that can only be described as arbitrary (e.g. the change in frequency of 'uncertainty events' and the 'benchmark level of uncertainty' in the Monte Carlo analysis used to assess 'durability benefits' – see section B.2.6).

Relying on such inherently uncertain parameters and assumptions undermines significantly the reliability of any modelled outcomes and the resulting estimated net benefit. This should have been readily apparent to the Authority if it had stepped back and taken a broader look at the various counterintuitive impacts that its model was predicting, e.g., the implausible influx of new generation, etc. More generally, the needless complexity of the modelling makes it impossible to comprehend for all but a select audience and serves to mask the fundamental shortcomings with it.

B.2 Assumptions and outputs that do not reflect reality

There are several prominent instances within the CBA where assumptions have been made that do not reflect the way the electricity market actually works or how the actors within it make decisions. For example, the modelling assumes that:

- final consumers are exposed directly to transmission costs and wholesale prices when, in reality, these are not directly passed on by retailers in the vast majority of cases – a situation that is unlikely to change any time soon;
- generators decide whether to invest in new places by looking at a single year's worth of wholesale market returns, which ignores the fact that it is *projected future cashflows* that drive those decisions in practice – a function of both projected wholesale prices *and* dispatched generation;
- significantly fewer grid-scale batteries would be invested in if the Authority's proposal proceeded, which is highly speculative given the implicit assumptions made in the modelling;

378 There are, in fact, many more equations and formulas used throughout the spreadsheets and computer code used to apply the CBA.

- wholesale prices would drop significantly if demand increased, which does not follow as a matter of economics;
- significant opportunities exist for customers to further scrutinise transmission investment and that this would lead to superior investment decisions, when there is no theoretical or empirical basis for thinking so; and
- the proposed methodology would reduce policy uncertainty for investors, which is inconceivable given the uncertainty that would surround the estimation of benefits and numerous other elements of the framework.

Naturally, when a model does not reflect accurately what it is supposed to be depicting the results that it produces cannot be relied upon. In this instance, the Authority's CBA is simply unfit for its intended purpose.

B.2.1 Consumers directly face transmission and wholesale prices

A key assumption made by the Authority in its grid use modelling is that 'mass-market load would respond to both transmission and wholesale price signals over the period to 2049'.[379] This assumption is fundamental to its estimated benefits from more efficient grid use. However, given current retail offerings and uptake by consumers, the presumption is not realistic.

Almost all residential consumers face no peak period pricing signals. Moreover, moves to increase the complexity of consumer bills to include time of use or peak pricing have been resisted. Orion's recent discussion paper[380] provides a useful synopsis of the challenges that it is facing. In short, there is a clear divergence between what the Authority would ideally like it to do – i.e., to provide more 'granular signals' – and what its customers would prefer.

Experience in other infrastructure sectors (e.g. telecommunications) has also shown a strong consumer preference for simple flat-rate fees (e.g., 'all you can eat' fixed cost per month for mobile and broadband plans or fully variable 'pay as you go' prepay mobile plans) that signal nothing about the costs of using that infrastructure at peak times. Indeed, the mobile telephony sector looks nothing like the Authority's predicted future state of the electricity sector.

To be sure, the Authority has and continues to develop pricing principles designed to deliver more cost-reflective electricity tariffs which, if effective, *may* mean that distributors will eventually be forced to directly pass-through (via retailers) costs to those final customers that cause them. However, it is unclear how successful these reforms will turn out to be and whether government policy and consumer preference will ultimately inhibit cost-reflective tariffs at the retail level.

As it stands right now, the world that the Authority seems to be envisaging in its CBA is a far cry from the electricity market that we see today. As we explained in

379 Electricity Authority, 23 July 2019, *2019 issues paper: Transmission pricing review*, *Consultation paper*, footnote. 45.

380 Orion, *Orion Delivery Pricing, Discussion Paper 2019*, 3 September 2019 (available: here).

section 2.3.2, the Authority attempts to 'assume this problem away' by claiming that it does not actually matter if final customers are exposed to granular transmission and wholesale price signals. Recall that it states instead that:

> *'…it is likely that retailers will endeavour to manage that risk by entering into a contract with a counterparty (such as a generator), so that the price risk is shifted to a party that is better placed to respond to nodal price variations. This means that,* ***even though the mass market consumer does not respond to nodal prices, the behaviour of other parties compensates for this so that the grid use responds as if they do****.'* [our emphasis]

In other words, the contention is that retail customers *themselves* do not need to see and respond to price signals, because other entities – e.g., the customers' retailers – would respond in their stead. The overall effect is therefore said to be exactly the same as if the customers had been exposed directly to the price signals themselves. However, as we explained in section 2.3.2, this contention is incorrect.

To be sure, retailers do engage in strategies to manage nodal prices on behalf of their customers. However, there is no reason whatsoever to think that a consumer paying retail prices where the ebbs and flows of spot market movements have been 'smeared' across time – which is an inevitable consequence of almost every retail contract – would have the same consumption profile if she had been exposed directly to the half-hourly fluctuations in spot market rates. And yet, that is precisely what the Authority is suggesting. This assumption does not represent how the market works, or how consumers and retailers behave.

Yet, the grid use modelling assumes all these problems away by modelling demand *as if* consumers responded directly to ongoing changes in wholesale prices and interconnection charges. The measured changes in consumer surplus are also a product of that same, unsound assumption. If that assumption is wrong – which seems highly likely, given that consumers do *not* currently face those price signals – then the grid use modelling results cannot be correct. For example, the demand response would be less than forecast, the investment required to meet it would be lower, as would be the measured change in consumer surplus. These failings all serve to undermine further the credibility of the CBA results.

Even the Authority's own modelling suggests that consumer demand does not respond to changes in *retail* prices. The elasticity estimates derived from historical retail price changes are *statistically insignificant*. Faced with this difficulty, the Authority opts to estimate elasticities based on *wholesale* prices.[381] In other words, despite being faced with evidence that final consumers *do not* respond to retail price signals, it opts to use the correlation between wholesale prices and consumer demand as a proxy for responses to retail prices in the grid use model.[382] This is clearly inappropriate.

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381 However, as noted in section 0, many of the elasticities estimated using wholesale prices turned out to be statistically insignificant as well. This can be seen in column E of Table 10 in the Technical Paper, which shows that p-values often well above the 5% significance level.

382 We use the term 'correlation' here quite deliberately. Without more, all that the regressions used to estimate the elasticities tell us is that there is some correlation between wholesale prices and demand. Other factors could be driving the correlation, such as changes in actual or projected

B.2.2 Decisions to invest in generation are irrationally myopic

A key driver of the change in consumer surplus calculated by the Authority is the additional grid-connected generation investment that the grid use model predicts. That investment results from applying an investment decision rule that makes very little sense. In fact, it causes the model to predict that generators would invest in additional plant that may *not be profitable,* i.e., it potentially gives rise to *inefficient* investment. The Authority describes the rule as: [383]

> *'The modelling of generation investment assumes investors will install new generation plant in a given region after short-run wholesale prices in that region exceed long-run marginal cost in any year.'*

In other words, the entry 'decision rule' that is adopted (equation 25 in the Technical Paper) assumes that generators would assess the financial viability of potential investments by looking only at *past and current returns* – and for a *single year*. It also assumes that new generators would dispatch *all* of their capacity at the average dispatched per MW price.[384] That does not comport with reality and is diametrically at odds with efficient investment decision making. Like in any market, entry decisions are based on one principal factor: *projected future cashflows*.[385]

To that end, one of – if not the single – most important matter that a firm would consider before investing in new generation is expected *future* wholesale prices. To be sure, past and current spot prices may be a key factor in a generator's assessment of future prices, but they cannot substitute for them. For example, if a generator anticipated that its entry – and/or entry/expansion by others – would lead to a sharp reduction in nodal prices, then it may be disinclined to invest. Similarly, a new entrant would take into account expected dispatch – it would not simply assume full utilisation.

In other words, even if spot prices are 'high' when a decision is being made, it does not follow that entry will occur as a matter of course. A decision rule that focuses exclusively on past returns will lead to efficient investment outcomes only by pure coincidence. Of course, it would have been far more difficult for the Authority to model future profitability and to factor that into the grid use model. Adopting a simpler approach has avoided those challenges, but at the cost of compromising significantly the utility of the modelling, as evidenced by the clearly counterintuitive results that it is producing.

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demand driving wholesale price changes. The uncertainty arises because annual demand quantities and prices are being used, when, in practice, demand response (to prices) occurs over much shorter time periods.

383 Third Issues Paper, p.25.

384 This is confirmed by inspecting the Python code used to implement the decision rule in the grid use model.

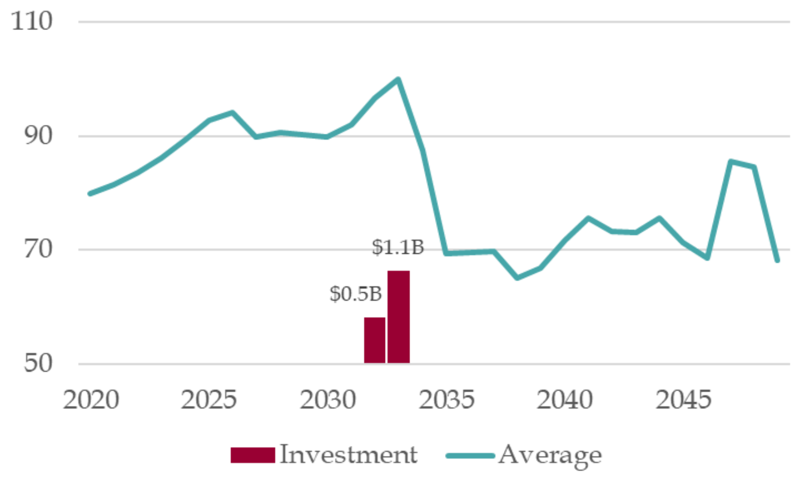
385 *See for example:* Copeland, Weston and Shastri, 2005, *Financial Theory and Corporate Policy*, Fourth Edition, p.18, where the authors explain that 'the objective of the firm is to maximize the wealth of its shareholders…[which is] more carefully defined as the discounted value of future cash flows'.

As we explained earlier, the model is predicting that generation investment would increase by $3.8b in total over the 2020 to 2049 period, while generation revenue (net of interconnection charges) would *fall* by $13.2b.[386] That is a very poor return on investment, to put it mildly. As we indicated earlier, this strikingly incongruous result appears to be the product of the economically perverse decision rule contained in the model.

That rule assumes that generators would continue to happily invest very large sums even though spot prices were decreasing sharply as a consequence. The economic viability of much of the investment that the model is predicting would be marginal *at best*, in *prospective* terms. The wave of new generation investment that is driving the net benefit estimate would therefore be unlikely to happen. The lower wholesale prices that are driving the lion's share of the Authority's net benefit estimate therefore appear to be illusory.

Two examples from the grid use model may help illustrate this problem. First, in the scenario in which the proposal is adopted, the model predicts that 120MW of generation would be connected to the Haywards backbone node over 2032–2033, at a cost of $1.6b. In the lead up to that investment, prices at that node are assumed to be increasing steadily. However, in the wake of that investment prices dive dramatically and never recover. A similar story plays out at the Islington node. The model predicts over $1.7b of investment in 2034 that adds 255MW of capacity and a further $2.3b in 2036 that adds 330MW more. These examples are shown in Figure B.6 and Figure B.7.

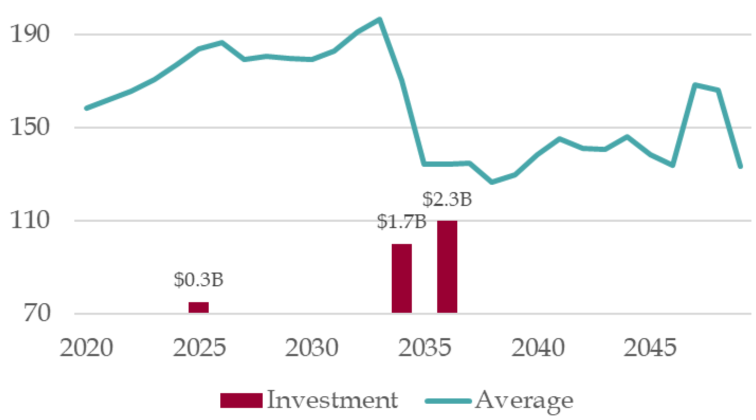
Figure B.6: Generation investment and average wholesale prices at Haywards backbone node ($billion, 2018 dollars)[387]



386 Both values are in total dollar terms. Note that the $1.9b in additional generation investment referred to earlier was in NPV (discounted) terms. In other words, generation investment increases by $3.8b in *total* over the 2020 to 2049 period relative to the status quo, and by $1.9b in *NPV terms*.

387 Data are sourced from the 'AOB.csv' and 'plant_investment.csv' spreadsheets for the 'All_major_capex' scenario. The average price for a given is calculated by multiplying the generation prices for each time period at the backbone node by the equivalent quantity, summing these together, and then dividing by total quantity for the year.

Figure B.7: Generation investment and average wholesale prices at Islington backbone node ($billion, 2018 dollars)[388]



In the real world, it is highly unlikely that a sophisticated, commercially minded, investor would deploy such significant amounts of capital without first considering the likely effect on future wholesale prices. If faced with such precipitous potential wholesale price reductions, no reasonable investor would elect to build additional generating plant – or, at the very least, she would not install units on the scale assumed by the grid use model. The model is therefore divorced from reality.

B.2.3 The proposed TPM would lead to significantly fewer grid-scale batteries

The grid use model predicts that if the proposal proceeds, investment in grid-connected batteries would decline by $202m in NPV terms relative to the status quo. The theory appears to be that, unless the RCPD charge is removed, $202m worth of additional grid-scale batteries would be deployed to arbitrage between peak and off-peak RCPD periods or to simply to avoid peak charges. The proposal would remove the incentive for that investment by collapsing the distinction between peak and off-peak transmission prices, thereby removing the potentially profitable arbitrage opportunity or the ability to avoid peak charges. However, there are several problems with this theory in practice:

- Investing in grid-connected batteries in such circumstances would be very risky. If the TPM changed subsequently in a way that removed or reduced the peak/off-peak distinction or if investment in batteries by other parties was wide-spread, then the arbitrage opportunity or the ability to avoid peak charges could become less lucrative/effective or vanish altogether – leaving a stranded (and expensive) asset.
- Much like the grid-connected generation investment decision rule (discussed in section B.2.2), the grid-connected battery investment decision rule does not

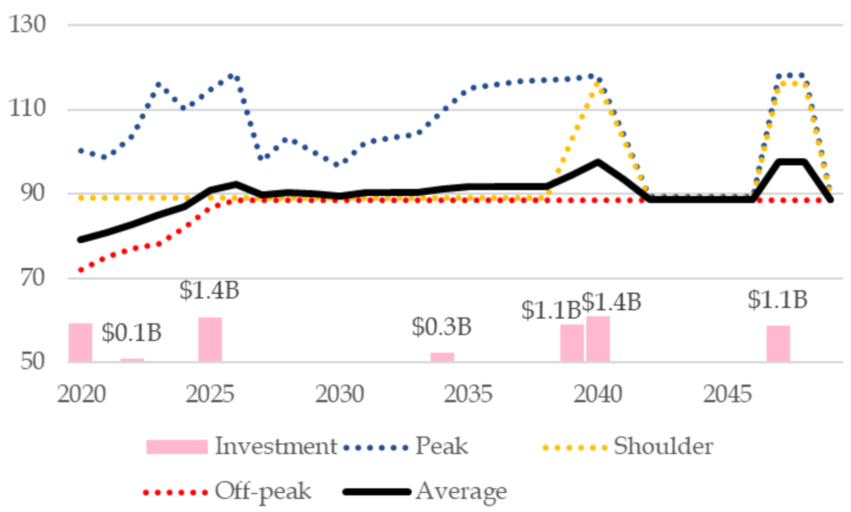
388 Data are sourced from the 'AOB.csv' and 'plant_investment.csv' spreadsheets for the 'All_major_capex' scenario. The average price for a given is calculated by multiplying the generation prices for each time period at the backbone node by the equivalent quantity, summing these together, and then dividing by total quantity for the year.

consider *future* generation prices (although it does consider future transmission charges). For analogous reasons this rule is therefore unrealistic, since prudent investors would consider future returns when making investment decisions.

- Arbitrage competitors already exist. For example, hydro generators can effectively 'store' energy by holding water in storage lakes. It is therefore unclear what additional gains a *grid*-connected battery could effectively make.[389]
- The cost of batteries is likely higher than the Authority has modelled. The Authority has used the estimated cost of the South Australian 100MW Tesla battery, based on news sources. This figure is about 36% lower than the actual value, which was reported recently by the battery's owner, Neon.[390]

Looking at the first limitation, this appears to have played out in the grid use model. Figure B.8 illustrates that the predicted battery investment in the status quo converges generation prices across time periods. If it were not for the price caps and floors imposed within the model (see section B.5.3), it is quite likely that the peak price would have fallen below the off-peak price, reducing returns on batteries that discharge during the peak period to avoid RCPD charges. Interestingly, from the point where prices start to converge (around 2040), investment in new batteries ceases.

Figure B.8: Breakdown of generation prices - status quo ($/MWh, $2018)[391]



389 Certainly, distribution-connected batteries could potentially make bigger gains, since they could be used to avoid peak transmission charges. However, they would then face the prospect of facing distribution peak charges (especially if they are large peak users of the distribution network), which the Authority's distribution pricing principles are likely to encourage distributors to implement.

390 Specifically, the Authority assumed a capital cost of $733k per MW, based on news reports about the Tesla battery. The cost of the 100MW battery was reported in recent regulatory filings as €56m, which at the current exchange rate is almost $100m, or $1m per MW. See: Neon, *Document de Base (Registration Document) of Neon*, p.432 (see: here).

391 Data are sourced from the 'RCPD.csv' file for the 'All_major_capex' scenario. Average prices were calculated for a given year and time period by multiplying prices for each backbone node by the corresponding consumption quantities and then dividing the result by total consumption for that time period and year.

Looking at the fourth limitation, if the starting price of batteries were lifted to $1m per MW of capacity, then the value of avoided batteries would reduce by over $35m to $165m in NPV terms.[392] If the generation price caps and floors were also removed, then the avoided battery investment reduces to *negative* $257 quadrillion (i.e. -$257 million billion) in NPV terms (i.e., it would result in more investment under the Authority's proposal – a *lot* more).[393]

Overall, if all of the above factors were reflected in the battery investment decision rule and modelling, then the projected avoided investment in grid-scale batteries under the Authority's proposal would be a lot lower. However, given the absurd results that are produced when different assumptions are employed (i.e., when the arbitrary caps and floors are removed) it is impossible to know for sure what the result would be since, ultimately, the model is not robust.

B.2.4 Wholesale prices decline in response to higher demand

As we mentioned earlier, one of the more counterintuitive results from the grid use model is that average wholesale prices are predicted to *fall* substantially in response to an increase in demand in the scenario in which the Authority's proposal is implemented. As a matter of economics, it is not at all clear why an enduring increase in demand in peak periods would lead to a large average price *reduction*. Why would the supply-side response outweigh the demand-side effect – and by such a considerable margin?

As we explained in the previous section, this supply-side reaction arises largely because of the unrealistic entry decision rule that the Authority has included in its analysis, whereby generators are assumed to disregard future prices (and revenue) when choosing whether to invest. As we noted earlier, this serves to highlight further the wholly unreliable nature of the benefits estimates that the model has produced.

B.2.5 More consumer scrutiny could lead to more efficient investments

The Authority has assumed that $77m in benefits would be obtained by consumers facing BB charges subjecting Transpower's investment proposals to greater scrutiny.

392 This was estimated by:

- taking the 'AoB_All_Major_Capex.py' Python script for the 'all_major_capex' scenario and updating the 'dg_capex' input parameter to 1000000 and the 'dg_lrmc_mu' input parameter to $336.6 (being the levelised long run marginal cost per MWh if the initial capital cost were $1m instead of $733,000); and
- taking the 'Aggregates.py' Python script for the 'all_major_capex' scenario and updating the 'dg_capex_per_mw' to 1000000;

and then sequentially re-running both scripts before estimating the change in the 'total_dg.csv' output file.

393 This was estimated by taking the 'AoB_All_Major_Capex.py' Python script and removing the price cap and floors at lines 416 to 429. The result is clearly ridiculous; but it highlights the import role that the price caps and floors play in ensuring that the battery investment predictions appear more realistic (even though they are not likely to be realistic for the other reasons noted).

We explained in section 4.3 why there is no reason to think that there is a problem with the Commission's grid investment approval process that needs solving. We also set out the reasons why the Authority's proposal would be likely to *compromise* those proceedings (which we do not repeat here).

There is therefore no cause to think, as a matter of economic principle, that there are *any* benefits on offer from 'greater scrutiny of investments' by customers. The Authority's CBA does not establish otherwise. For starters, the Authority relies on just a single observation. Namely, it notes that the Commission reduced Transpower's proposed enhancement and development (E&D) base capex projects allowance by 4.4% between the draft and final determinations for the second regulatory control period (RCPD2).[394]

From this single datapoint, the Authority assumes that it can apply efficiency factors of 4%, 2%, 1% or 0% to Transpower's proposed capex over the 2022 to 2049 period, depending on the type of expenditure. These assumed percentages applied to that future expenditure program yield the $77m benefit estimate. Relying on a single observation is inherently risky in the best of circumstances – and even more so when it is being used to project benefits out to 2049. Here, the problems are even greater, in that:[395]

- the 4.4% reduction followed scrutiny from *the Commission*, not *customers*, i.e., it is not a relevant metric because the Commission will be able to perform a similar oversight role for *future* transmission proposals – the reduction was not achieved because BB charges were in place (because they were not);
- the *relevant* question is whether reductions were on offer *above and beyond* those identified by the Commission and, given the multitude of practical factors described above, that seems highly unlikely if not implausible, i.e., the Commission is in the best position to identify potential efficiencies; and
- it is also possible that the Commission got its decision wrong – regulators and their advisors can and do make mistakes, which is one of the many reasons why it is imprudent to base an entire analysis on a single observation (and, in this case, on an irrelevant one).

Perhaps even more problematically, the Authority appears not to have realised that its model assumes implicitly that the additional 4.4% that Transpower was proposing to spend would not have delivered *any benefits at all*. That assumption is

394 Third Issues Paper, p.42.

395 The methodology is very similar to the approach the Authority used to arrive at its $173.2m net benefit estimate in its First Issues Paper. There, it multiplied total sector revenue (based on assumed growth rates) by an 'efficiency parameter' of 0.3%. The Authority sought to justify the selected efficiency parameter by comparing it to the long run total factor productivity (TFP) growth rate that had been applied by the Commission to determine the default price-quality paths for electricity distribution businesses. However, as Axiom's economists pointed out, these two factors were not measuring the same thing and the comparison therefore could not reveal anything meaningful about the robustness of the assumed value. The parallels here are quite striking. Here again, the Authority is multiplying large numbers (in this case, future capex projects) by efficiency factors that have been assumed, rather than estimated. And, once more, those assumptions have no sound basis. *See:* Green *et al*, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, pp.16-17.

not appropriate. It is virtually impossible to conceive of any scenario in which that additional capital expenditure would have delivered *zero* benefits.

The Commission presumably determined simply that the benefits that would be delivered by the additional 4.4% of investment did not justify the cost. To use a simple example, if Transpower was proposing to spend $1,000 (to use a round number), the Commission might have determined that $44 (4.4%) of that sum would deliver only $40 in benefits and cut the allowance to $956. However, in this stylised example, the efficiency gain is not 4.4% ($44 ÷ $,1000), it is *0.4%* ($4 ÷ $,1000).

In other words, even if the 4.4% datapoint upon which the Authority has based the entirety of this modelling was relevant (which it is not), it is *clearly the wrong number*. The *true* efficiency gain would be likely to be many magnitudes smaller than 4.4% and, by extension, the percentages that the Authority has adopted are also likely to be overstated substantially. As such, even on its own terms, the $77m estimated by the model is artificially inflated – most likely considerably.

Finally, the model does not take into account the additional costs that Transpower, the Commission and stakeholders would incur as a result of that additional scrutiny. If the Authority's theory is to be believed, all parties would need to prepare or engage with additional material and participate fulsomely throughout the process, relying on internal resources and often external support. These extra costs would be significant, and none have been factored into the analysis.

B.2.6 The proposed TPM would reduce uncertainty

The CBA assumes that investors would benefit from reduced uncertainty if the Authority's proposal was implemented – to the tune of $26m. There is no doubt that reduced policy uncertainty can lead to economic gains.[396] However, as we explained in section 5.2.1, prior to the October 2012, the TPM had been relatively stable. The extensive work of the two reviews that commenced in mid-2009 had concluded that, although the TPM was not perfect (which no pricing methodology ever is), there was no need for radical reform.[397]

Since that time, all the uncertainty has been created by the Authority's review, which has fallen short of best regulatory practice in numerous respects. For that reason, it is somewhat counterintuitive for the Authority to assert that a core benefit of its proposal ($26m) is 'increased certainty to investors'. In our experience, it is highly unusual – and arguably more than a little self-serving – for a regulator to assign a large benefit to clearing up the very uncertainty that it has created through its own actions.

In this particular instance, improved durability could be obtained far more simply by the Authority stating categorically that it is stopping its review and not contemplating any changes to the TPM for, say, the next ten years. Or, alternatively, certainty might be achievable if the Authority proposed a more economically

[396] Third Issues Paper, p.44.

[397] The main exception to this was the cost allocation enshrined in the HVDC charge.

orthodox reform option, such as an LRMC-based pricing option – a candidate suggested by several parties throughout the review. In contrast, it is highly unlikely that the proposed option would do much – if anything – to reduce uncertainty.

Throughout this report we have documented the plethora of problems that would afflict the proposed methodology if it was to be implemented. Substantial uncertainty would surround the estimation of benefits, the durability of those charges over time, the scenarios in which they would be revisited and, ultimately, the durability of the regime. In our opinion, there is a very good chance that these problems would render the methodology unsustainable and prompt major changes to be made in the near-term to make it more workable.

All of these practical realities are ignored in this aspect of the CBA modelling. On its face, the model appears to be very sophisticated. However, when the elaborate computer code is stripped away it becomes apparent that the results are driven primarily by two crucial inputs; namely:

- an assumption that the proposed TPM would defer the frequency of 'uncertainty' events (i.e., a major review of the methodology) from 1 every 10 years to 1 every 11 years; and
- the selection of '100' as the benchmark level of uncertainty – which is an assumption that is required to translate the top-down modelling framework into a benefit estimate.

There is no objective empirical basis for either of these inputs. As for the first assumption, no analysis at all is presented to justify the selection of the 10- and 11-year periods. They are guesses. Changing those intervals has a substantial impact on the estimated benefit. For example, if one assumes instead that the proposal would lead to an 'uncertainty event' once every 21 years instead of every 20 years, the estimated benefit drops to around $15m. It is alarming that the result is so sensitive to such a spurious assumption. The second input is even more worrisome.

The second assumption undermines completely the efficacy of the modelling. In order to produce a benefit estimate, the model must assign a baseline 'value' to uncertainty. Ideally, the benefits estimate would not hinge upon that number. After all, it is a purely random baseline value – it is not something that *can* be quantified. In other words, it should not matter whether the model uses 1, 100, 1,000 or 1,000,000,000 for that 'baseline' value. Each of those equally viable candidates should yield *the same answer*.[398]

But they do not. The Authority picks a baseline value of 100 – as good a selection as any other – and this produces a benefit estimate of $26m. However, if it had picked 1,000 – a no less viable candidate – the benefit would have been more than 10 times higher, at over $260m.[399] And if it had selected a baseline value of 1 – which, again,

398 For example, changing the base value in the consumer price index (CPI) from 1,000 to 10,000 would not change the estimated quarterly rate of headline inflation.

399 This would be the equivalent of Statistics New Zealand changing the base value in the CPI from 1,000 to 10,000 and concluding that the quarterly rate of headline inflation was 10% instead of 1%.

is no more 'right or wrong' than any other number – the benefit estimate would be nearly zero. This problem is fatal to the model's credibility. It is no exaggeration to state that the model is little more than a random number generator.

The Authority presumably tested a variety of different combinations of inputs before deciding upon 10-years/11-years and 100. That begs the question: why did it decide upon 100 instead of, say, 1 or 1,000, or on 10- and 11-year periods instead of, say, 15- and 16-year windows? The most logical answer is that those values were selected because of *the benefits value they were producing*, i.e., the number might have 'seemed about right'. However, that is reverse engineering and not an appropriate way in which to perform a CBA.

B.3 Inconsistencies and contradictions

The CBA also includes several inconsistencies and contradictions that raise doubts about the robustness of the estimated costs and benefits – including whether certain items should be added together at all. Our key concerns include:

- treating the avoided cost of investment in grid-connected batteries as a benefit while ignoring the additional investment in grid-connected generation as a cost;
- similarly, leaving in the benefit to consumers from additional investment (e.g., lower prices), but ignoring the costs of creating those benefits (e.g., investment in generation);
- leaving in wealth transfers from generators to final consumers, but adjusting for wealth transfers from final consumers to generators from redistributed interconnection charges;
- including shadow prices (albeit the wrong ones) when assessing benefits from more efficient investment, but ignoring them altogether when modelling grid use benefits; and
- predicting reductions in grid investment when assessing benefits from scrutiny and more efficient investment yet forecasting increases when assessing benefits from more efficient grid use.

It is unclear what has led to so many inconsistencies. One possibility is that different parts of the modelling were performed by different people and/or organisations and no attempt was made at the end to 'reconcile' the various components to ensure that consistent assumptions had been employed. Whatever the cause, the result is a CBA that lacks coherency. We discuss the concerns listed above further below.

B.3.1 Factoring in avoided battery costs but not new generation costs

One of the larger benefits said to flow from the proposal is $202m from 'more efficient investment in batteries'. This benefit would supposedly arise in the form of an *avoided cost*. However, as we have stated previously, despite counting these *avoided* capital costs as benefits, the model excludes many of the *additional* capital outlays that are said to stem from the proposal. Recall, for example, that the grid use model estimates that an extra $1.9b in grid-connected generation would be needed to meet the forecast increase in demand.

This additional generation cost is nearly ten times higher than the $202m that has been included in the benefits assessment. As we noted earlier, this exclusion is justified in the following way:[400]

> *'The CBA does not include any costs for generation investment brought forward. This is because the generation sector is assumed to be competitive, so any generation investment that occurs as a result of the proposal is assumed to be efficient investment.'*

This is not a satisfactory explanation. As we explained previously, not all investment in generation can be presumed to be efficient in an economic sense. The contention that the additional generation expenditure can be disregarded *in this instance* rests solely on a subjective belief that, because it would be happening in response to the proposal, it must be efficient, and can therefore safely be omitted.

By the same rationale, because the $202m in expenditure on batteries etc. would *not* be happening as a result of its proposal, it can also be presumed to be efficient and counted as a benefit. The bias in this approach should be obvious. The analysis is starting with the *a priori* assumption that the proposal would be efficient and then characterising everything that flows from it – whether that may be avoided costs or additional costs – as 'good'.[401] This is not an appropriate way to perform a CBA.

If the CBA were designed correctly it would automatically pick up efficiency gains or losses by looking at the *total costs and benefits* across the entire electricity supply chain. In this case, there would be a net $1.7b *additional cost* arising from extra grid-connected generation and avoided storage costs.

B.3.2 Including the benefit from generation but not the cost

The CBA also includes the benefits from additional grid-connected generation, but not the costs of it. That is clearly inconsistent. It is like measuring the net benefit that a child derives from a new car as the satisfaction she gets from it plus the avoided bus fares, while ignoring what her parents or guardians had to pay for it in the first place. In the model, additional generation leads to lower wholesale prices (somewhat inexplicably – see section B.2.3), which appears to be driving the $2.6b in benefits from more efficient grid use. This is based on two key observations.

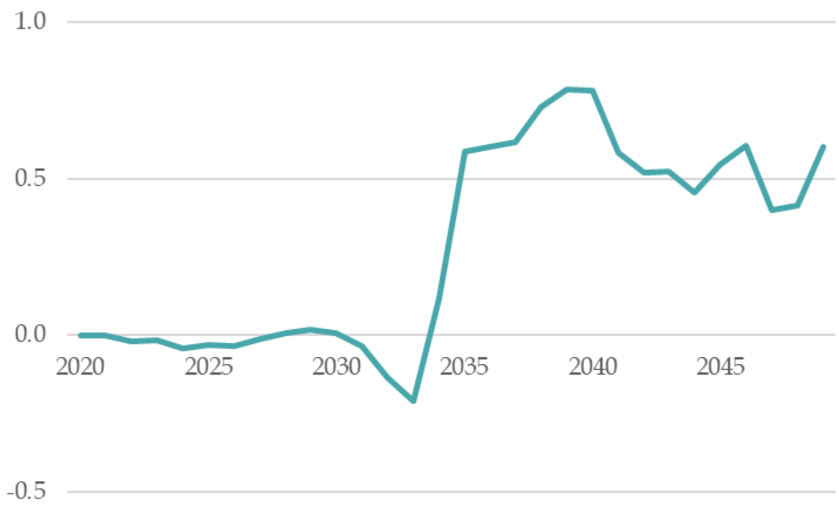
First, consumer surplus increases significantly only after the forecast investment in new generation takes places, leading to significantly lower prices from 2034 onwards (see Figure B.9 below). Second, the consumer surplus gain remains significant even after changes in interconnection charges and transport costs are stripped out. Specifically, we estimate that at least $2.1b of the increase in consumer

400 Third Issues Paper, p.47.

401 Or, in the case of the additional distribution expenditure that would be likely to arise from the proposal, it concludes that it is 'beyond the scope' of the analysis.

surplus gain is due to generation prices changing, or roughly 95%.[402] It is therefore clearly the key driver.

Figure B.9: Consumer surplus ($billion, 2018 dollars)[403]



In other words, the Authority has included a benefit of $2.6b in its CBA but has left out the $1.9b of additional costs that, based on the analysis set out above, is needed to produce it. To use another analogy, that is rather like financing the purchase of a new $1m home by selling your existing $1m home and concluding that you are better off to the tune of $1m. Plainly, that is not a robust way in which to assess the respective costs and benefits of such an exercise.

B.3.3 Inconsistent treatment of wealth transfers

As we noted earlier, the Authority acknowledges – rightly – that wealth transfers should not be included as benefits (or costs) in its CBA. However, it then removes only *some* of the wealth transfers in a way that creates a substantial bias in favour of its proposal. Specifically, the Authority:

- adds into the more efficient grid use benefit $368m of interconnection charges that are predicted to shift from generators to final consumers – apparently based on the assumption that there was a need to offset a wealth transfer cost already reflected in the CBA (as discussed in section B.1.4.2, this does not appear to be the case); but

402 We estimate that $4.2b of the $4.4b in consumer surplus gain, calculated assuming that prices *do* change, is due to generation prices changing. This is estimated by using generation prices in the consumer surplus gain calculation, rather than prices including interconnection charges, transport costs and energy costs. Averaging the $4.2b consumer surplus gain with the equivalent value estimated assuming that prices *do not* change, gives at least $2.1b. Clearly, this analysis can only ever be indicative because it is using values that do not sit on the demand curve to estimate the consumer surplus gain. However, it does illustrate that most of the consumer surplus gain (around 95%) is driven by the change in generation prices. Data are sourced from the 'AOB.csv' and 'RCPD.csv' files for the 'All_major_capex' scenario. Equation 10 is used to calculate the change in consumer surplus.

403 Data are sourced from the 'CS_results.csv' file for the 'All_major_capex' scenario.

- ignores a wealth transfer more than five times as large (of roughly $1.9b) that is wrapped up in its measured consumer surplus gain (see section A.5.1.3).

This inconsistent treatment appears to simply be a mistake, since there is no rational explanation for it. As we explained earlier, it represents a key failing in the CBA – and one that, in our opinion, has compromised singlehandedly the efficacy of the results. This error alone causes the benefit estimate to be overstated by $2.3b.

Ironically, the Authority employs a completely different approach when measuring durability benefits with its 'top-down' approach (see section A.5.2.5). In that model, it measures the change in *total* wealth, not just consumer surplus.[404] By doing so, wealth transfers are effectively ignored, since transfers from consumers to generators (and vice versa) net out. It is unclear why such inconsistent approaches have been used to address the same issue across different elements of the CBA.

B.3.4 Using shadow prices for one assessment, but not another

We observed earlier that the Authority has not included 'shadow prices' in its grid use model. That represents a key shortcoming because the modelling consequently does not depict the methodology that has been proposed. The Authority has, however, included shadow prices of a kind (albeit, not ones that reflect the signals that would *actually* be provided) in its modelling of the benefits from more efficient transmission investment; namely:

- in the modelling of 'more efficient investment' the expected impact (to consumers and generators) that increased peak demand or generation would have on future BB charges is accounted for explicitly – although, these price signals are mistakenly assumed to reflect LRMC which, in practice, they would not (i.e., the Authority has modelled the *wrong* shadow prices); yet
- no shadow prices *at all* are incorporated into the grid use model because the demand and grid-connected generation investment decision equations it employs do not consider future expected interconnection charges.

In other words, the Authority has modelled shadow prices inaccurately in one instance and ignored them in another. This inconsistency is puzzling – especially given the importance of the concept to the Authority's proposal. In truth, it would be very difficult to model exactly what would happen if customers were exposed to *the true* shadow price signals that they would face under the Commission's preferred methodology. But, given all the problems described hitherto, it is reasonable to assume that such a model would not predict a net benefit.

B.3.5 Predicting increases in transmission investment in one model, but decreases in others

The CBA also relies on inconsistent projections of transmission investment. On the one hand, the grid use model forecasts that the Authority's proposal would lead to a significant increase in transmission investment. That is because the proposal is

404 This can be seen in equation 38 of the Authority's Technical Paper (p.86).

assumed to lead to an increase in consumption during peak periods which, in time, drives the need for additional grid investment. On the other hand, the top-down modelling of 'more efficient investment' and 'increased scrutiny' predicts *lower* transmission investment. Clearly, both of these things cannot happen at once.

This contradiction is simply a manifestation of the compounding errors in the Authority's analysis. Its top-down model of investment decisions by load and generation includes the wrong shadow-price signals (i.e., they would not reflect LRMC) and, as such, its predictions cannot be relied upon. And the grid-use model contains numerous serious errors – including a failure to incorporate any shadow price signals *at all*. With these kinds of mistakes being made throughout the two models it is perhaps unsurprising that they are producing conflicting results.

B.4 Uncertainty inherent in the modelled results

Various aspects of the modelling introduce further intrinsic uncertainties. For example, the timeframe over which the costs and benefits have been measured is very long. The accuracy with which key factors can be forecast so far into the future is highly questionable. Other key modelling inputs and assumptions are also either materially uncertain, or appear to be statistically insignificant (i.e., mathematically meaningless). Calculation errors also raise further questions about the reliability of the modelled results.

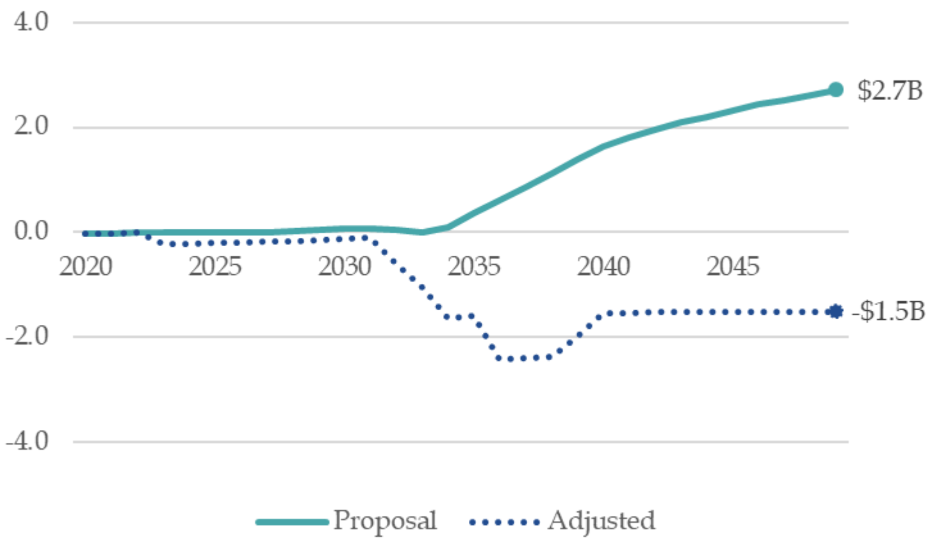
B.4.1 Time horizon has a significant effect on estimated net benefits

The time-profile of the Authority's net benefit estimate is very peculiar. Figure B.10 below illustrates the cumulative NPV of net benefits of the Authority's proposal over time. The green line is simply the result that comes out of the Authority's CBA – with all the errors described hitherto still in play. It shows that, even with all those mistakes left unaddressed, the projected net benefit from the Authority's proposal is *virtually zero* up until around 2034. Then, at that twelve-year mark:

- an influx of new generation is forecast to take place (unrealistically, for the reasons described in section B.2.2);
- forecast wholesale prices drop sharply (a wholly predictable outcome that generators are assumed to ignore); and
- from that point forward, net benefits grow steadily (remembering that almost all of this a bare wealth transfer and therefore not an efficiency benefit at all).

The dotted blue line shows what happens to the NPV of net benefits if the modelling is adjusted to address two of the more obvious errors – namely, to *exclude* the $2.3b of wealth transfers and to *include* the $1.9m of additional generation costs. This partially corrected cumulative estimate – now of a substantial net *cost* – follows a similar trajectory through time.

Figure B.10: Cumulative net benefits by time (NPV terms, $billion, $2018)[405]



The time profile of costs and benefits depicted in Figure B.10 calls into question why the Authority is insisting upon reforming the TPM now. The Authority has stated that it considers that changing the TPM is necessary and becoming increasingly urgent, since it is supposedly leading to inefficient investment and consumption outcomes.[406] Yet even taking its own CBA modelling at face value – with all its flaws – then:

- the proposal would not deliver a significant net benefit in NPV terms for *twelve years*; yet
- as we mentioned earlier, the Authority expects that there would be a significant 'uncertainty event' – such as a major TPM review – after *eleven years*.[407]

In other words, even on its own terms, the CBA model is suggesting that there would be eleven years of virtually no net benefits and then the TPM could change substantially. Consequently, even if all the errors in the CBA are ignored there is still no obvious reason to implement the Authority's proposed option – and certainly not as a matter of urgency.

Based on its own modelling assumptions, the proposal might deliver barely a dollar in net benefits before the methodology changes again. Moreover, even if those future benefits were not largely (if not entirely) illusory (which they appear to be in this case), it is doubtful that *any* model could make predictions with any reasonable degree of certainty so far into the future.

405 Data used to generate the net benefit profile were sourced from the 'CS_results.csv', 'total_dg.csv', and 'transmission _costs.csv' files for the 'All_major_capex' scenario, the 'transmission_costs.csv' file from the 'Demand_major_capex' scenario, the 'Investment efficiencies.xlsx' and 'Summary of costs and benefits.xlsx' files and results from applying the Python code were used to estimate investment efficiency benefits.

406 Third Issues Paper, p.ii.

407 As we indicated earlier, this eleven-year assumption has no objective basis. It is simply taken 'as given' here for the sake of illustration.

B.4.2 Key inputs and assumptions are highly uncertain or statistically insignificant

The CBA modelling relies on several key inputs and assumptions that are either highly uncertain or statistically insignificant. Relying on these values necessarily undermines the reliability of the modelled results. Some of the more consequential unreliable or unsupported assumptions include:

- the estimated effect of added scrutiny of Transpower's capex proposals, which is predicated on a single, irrelevant datapoint (the 4.4% reduction in the E&D base capex projects allowance between the draft and final determinations for RCPD2 discussed in section B.2.5);
- the assumed reduction in the frequency of 'uncertainty events' from one every ten years, to one every eleven years (as a central case) (discussed in section B.2.6); and
- the assumed base level of uncertainty (of 100) reflected in the market-clearing price (also discussed in section B.2.6).

Added to this, several key inputs to the grid use model are statistically insignificant or based on regression estimates that are mathematically meaningless. For example:

- thirty-six estimated elasticities used in the *time of use demand model* are statistically insignificant at the 5% level – which is almost half of the parameters estimated from that model;[408]
- the model-fit statistics for the chosen *aggregate, first stage, model of distribution-connected load* econometric model (an adjusted R^2 of 0.58 and an F-statistic of 88.11) suggest that there is a significant amount of variation in actual demand left unexplained by the model;[409]
- four of the six parameters estimated from that same model are statistically insignificant at the 5% level – one of which (the income elasticity of 0.11) is used as a direct input to the grid use model; and[410]

408 This was determined by first using R to run the code in the 'TOU_demand_model.R' file and then analysing the regression statistics contained in the 'laaids_mass_sd_restr_x' and 'laaids_dc_sd' R objects. The time of use model is applied by fitting equation 21 of the Technical Paper separately to actual data for distribution-connected and the equivalent for transmission-connected demand – giving 84 estimated parameters, of which 36 were not statistically significant at the 5% level (43% of the total number of parameters). If just the 48 parameters shown in Table 12 of the Technical paper are considered, then 19 of the 48 estimated parameters are not statistically significant at the 5% level (or 40%).

409 These statistics are shown in Table 10 of the Technical Paper. Comparing the statistics for the other models tested by the Authority, shown in the other columns of that table, suggest that noticeable changes to model structure and resulting parameter estimates do not materially change the model fit. For instance, the specification in column 'C' includes a statistically significant own price elasticity of -0.29 (compared to the -0.11 adopted in the CBA), with the same number of variables, a slightly lower F-statistic higher and a slightly higher adjusted R^2.

410 Again, this can be seen in the results shown in Table 10 of the Technical Paper.

- similarly, six of the fourteen parameters estimated from the translog cost model used in the *aggregate, first stage, model of industrial demand* econometric model are statistically insignificant at the 5% level.[411]

Given that it is inherently difficult fitting theoretical econometric models – such as those reflected in the 'almost ideal demand system' used in the CBA – to real world data, it is comes as no surprise that the Authority has wound up relying on so many statistically insignificant parameter estimates and model specifications. Nevertheless, because they *are* statistically unreliable, it is necessarily the case that the results from the grid use modelling that relies on them must *also* be unreliable. After all, 'rubbish in; rubbish out'.

B.4.3 Calculation errors undermine confidence in the modelling

There are also several examples of calculation or formula errors throughout the modelling. These are summarised in Table B.1. Although these examples do not necessarily undermine completely the calculated results, they do raise further questions about the CBA calculations. Put simply, we cannot be confident that other, perhaps even more material, errors remain within the modelling that we have not identified, despite out best attempts to traverse its many facets.

Table B.1: Example calculation errors

Error	Description
Durability example Excel formula error	The 'Durability' sheet to the 'Investment efficiencies model.xlsx' file provides *an example* of how the durability calculation is undertaken. Cell E40 of that sheet calculates the annual welfare change, attempting to replicate equation 45 of the Technical paper. That attempt, however, places a bracket in the wrong place. Rather than using the current formula of: *=+(1/2)*(($E$14*(1+$E$36)*($E$15+$E$38)-($E$14*$E$15)))+(($E$17-($E$14*(1+$E$36)))*($E$15+$E$38)-($E$17-$E$14)*$E$15).* The cell should instead have used the corrected formula: *=+(1/2)*(($E$14*(1+$E$36)*($E$15+$E$38)-($E$14*$E$15))+(($E$17-($E$14*(1+$E$36)))*($E$15+$E$38)-($E$17-$E$14)*$E$15)).* Correcting the formula by moving the bracket from the end of the first term to the end of the second, reduces the example benefit value by over $3m from $31.8m to $28.6m. This formula error does not appear in the Python code used to estimate the actual benefit adopted in the CBA.

411 This can be seen in the 'cost_function_results.csv' output file generated when running the 'CostFunctionEstimation.R' script in R.

Error	Description
Durability effect of uncertainty on price	Related to the example above, the durability benefit is calculated by considering how uncertainty affects price and quantity. The logic adopted in the CBA is that if uncertainty reduces then quantity will increase, pushing up total (final consumer and generator) welfare. The equations used, however, contain an error. Specifically, equation 43 of the technical paper notes that the effect of a change in uncertainty on price is as follows: $$\frac{\partial P}{\partial U} = \frac{\delta_s}{\beta} + \frac{\delta_d}{\beta} = \frac{\delta_s + \delta_d}{\beta}$$ That formula is not correct because there should be a negative sign in front of the δ_s term. The error appears to arise from incorrectly setting equations 36 and 37 equal to each other and then re-arranging the output to give equations 39 and then 43. The corrected equation should be: $$\frac{\partial P}{\partial U} = \frac{-\delta_s}{\beta} + \frac{\delta_d}{\beta} = \frac{-\delta_s + \delta_d}{\beta}$$ In the example (shown in 'Durability' sheet to the 'Investment efficiencies model.xlsx' file), this formula is shown at cell E20. Correcting it increases the example benefit value by more than \$13m from \$31.8m to \$45.0m. If, however, the bracket error identified above is also corrected, then there is no impact on the example benefit estimate. Correcting the formula in the Python code (row 175 of the 'Durability - monte carlo.py' file) appears to increase the estimated benefit by about \$4,000–\$5,000, depending on the simulation run.
Investment efficiencies transposition error	The 'Efficient investment' sheet in the 'Investment efficiencies model.xlsx' file provides *an example* of how the benefit from more efficient generation and large load investment decisions is calculated. Cells L30:L57 input the generation in export constrained areas data. Those data, however, are incorrectly transposed from the 'Generation capacity' sheet of the same file. Specifically, the data are out by two years; the 2019 capacity from the 'Generation capacity' sheet is being treated as 2021 capacity, the 2020 capacity is being treated as 2022 and so on. If the correct years were being used, then the estimated generation benefit shown in the 'Efficient investment' sheet increases by \$62,728.

B.5 Other issues

In addition to the concerns raised above, there are several other issues that raise doubts about aspects of the CBA results.

B.5.1 Net benefit range not quite right

The Authority calculates its net benefit range by subtracting the 'high costs' estimate from the 'high benefits' estimate; and the 'low costs' estimate from the 'low benefits' estimate. In certain instances, this approach may be appropriate. For example, for certain aspects of the modelling there may be a direct link between the benefits and costs (e.g., if each depends on a particular modelled outcome for a given scenario). In those cases, peering high costs with high benefits, etc., may be fitting.

However, in all other instances, the Authority's approach serves to artificially condense its net benefit range. That is because it could be the case that lower benefits are realised along with higher costs, or vice versa. Allowing for these eventualities would extend the net benefit range. As Table B.3. highlights, in the present case, the net benefit range would expand to something like $173m to $6.4b (ignoring all the other shortcomings identified hitherto).

Table B.2: Updated net benefit range (NPV terms and 2018 dollars, $million)

		Benefits	Costs	Net benefits
Authority's range	**Lower**	$266	$65	**$201**
	Upper	$6,749	$366	**$6,383**
Revised range	**Lower**	$266	$93[412]	**$173**
	Upper	$6,749	$338	**$6,411**

B.5.2 Other problems with the consumer surplus calculation

Putting to one side concerns over using the change in consumer surplus as a 'benefit' (see discussion in section B.1.4) and over the unrealistic modelled outcomes that drive the CBA estimate (see discussions in sections B.2.1, B.2.2, and B.2.4), the calculation is also problematic for other reasons. The Authority has attempted to address potential concerns with its estimated consumer surplus benefit by averaging:[413]

- the base estimate ($4.4b) calculated using equation 10 and including the effects of both changes in consumption and changes in prices; and
- an alternative ('conservative') estimate ($51m) that accounts for changes in volumes, transport costs and transmission prices, while holding energy prices constant.

The net result is the $2.2b estimate used in the CBA central case (before the $368m interconnection charge wealth transfer is added back). There are at least two problems with this approach:

- First, the alternative estimate is illusory. The model assumes that quantities would change in response to prices (via the demand model), but then peers those quantities with prices that have not changed. That alternative estimate is therefore based on points that are *not* on the demand curves (for the various year and time period combinations). This makes the estimate unrealistic and not robust. If the intent was to assess the change in consumer surplus assuming that prices do not change, then it would be more internally consistent to model

412 Although the high case estimated costs are higher (at $366m), this includes estimated grid investment brought forward (of $325m) that corresponds with the high case estimated grid use benefits. As such, for the lower range the low case estimated grid investment brought forward is used instead.

413 Technical Paper, p. 16.

demand response and generator and battery investment decisions in a way that resulted in no price changes.

- Second, the same averaging was not applied to the interconnection charge wealth transfer (of $368m) that was added back to the $2.2b to produce the overall $2.6b net benefit estimate from more efficient grid use. This means that there is an inconsistency in the grid use benefit estimate (of $2.6b), since one part (the $2.2b) is an average of two estimates: one of which assumes that energy prices do not change, while the other (the $368m transfer) is not.

More fundamentally, the consumer surplus assessment used in the CBA assumes unrealistically that consumer demand:[414]

- has a linear relationship with prices;
- does not vary by income level; and
- during peak periods does not depend on demand at other times.

Even within the grid use model, these assumptions do not hold. For instance, equation 2 notes that the demand function includes income as a parameter. Similarly, the estimated cross-price elasticities used in the grid use model clearly show that there are interrelationships between prices in one time period and demand in another.[415]

B.5.3 Generation price caps and floors

The grid use model places restrictions on how much dispatched generation prices can go up or down relative to past observed maximum and minimum prices. It does so in the following ways:[416]

- off-peak period prices cannot fall below $40/MWh or rise above $79/MWh;
- shoulder period prices cannot fall below $79/MWh or rise above $178/MWh or the corresponding peak price; and
- peak prices cannot fall below $79/MWh or rise above $246/MWh.

The Authority explains that these bounds are needed because the 'simplified model' does not allow for feedback between prices and demand or generation:[417]

> *'Caps and floors are necessary because our simplified model has only a sequential (lagged) relationship between demand and prices, so there is no feedback loop between high prices and reduced demand. There is also no feedback between price and increases in the amount of*

414 Technical Paper, p.15.

415 See, for instance, Technical Paper, Tables 13 and 14. *If* there were to be no relationship between the time periods, then those cross-price elasticities should be zero. Although this logic assumes that demand and price in one period are related, this would appear reasonable given that that is the basis for the demand model used in the grid use model and supported by standard economic theory.

416 These limits are hardcoded directly into the Python code used to run the grid use model. The specific values shown were taken from the 'AoB_All_Major_Capex.py' file.

417 Technical Paper, p.47.

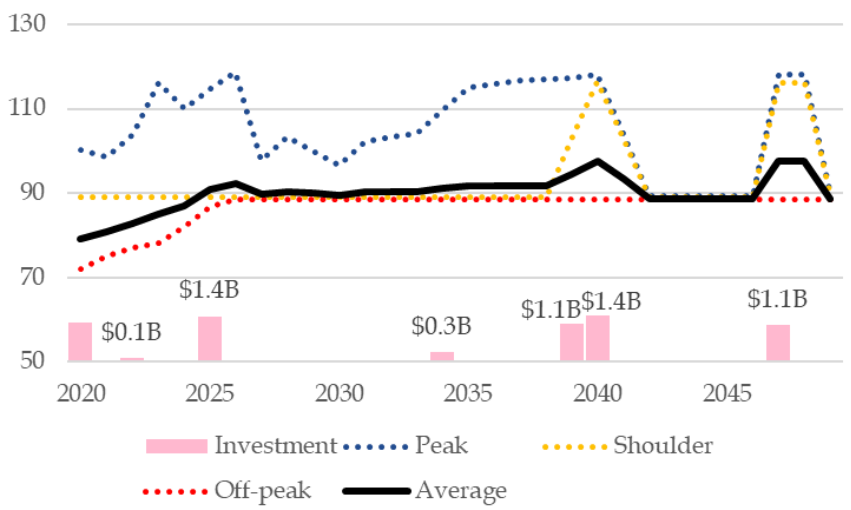
generation offered (i.e. generators are assumed to offer at their typical annual amount, conditional on the time of use in question). Furthermore, the model evaluates demand based on average MW per period and then applies the resulting prices to all hours during a time of use (peak, shoulder, off-peak). Thus, prices that emerge from the model may well be quite reasonable for a number of trading periods, but they would not persist for, say, 800 trading periods.'

The fact that the Authority has deemed it necessary to impose such bounds is not overly surprising. There are well-recognised challenges associated with implementing demand models of this type in practice – especially one requiring so many assumed relationships, data inputs and assumptions. However, imposing such restrictions can lead to counterintuitive results.

In this case, the bounds appear to – at least in part – be driving the peculiar (quantity-weighted average) generation price forecasts predicted for the status quo. As we showed in Figure A.6 (repeated here as Figure B.11), the average generation prices appear to 'top out' artificially for much of the period. For instance, the shoulder period price sits at $89.2/MWh and only deviates above this on two occasions (once over 2039–42, the other over 2047–48). These instances correspond to investments in grid-connected generation.

Similarly, the off-peak period price sits at $88.4/MWh from 2026 to 2049. The peak period price jumps around a little until it converges with the shoulder period price from 2039 onwards.

Figure B.11: Breakdown of generation prices - status quo ($/MWh, $2018)[418]



Although we do not know for certain that it is the bounds that are partly driving these outcomes,[419] whenever such restrictions *are* imposed there is always a risk that

[418] Data are sourced from the 'RCPD.csv' file for the 'All_major_capex' scenario. Average prices were calculated for a given year and time period by multiplying prices for each backbone node by the corresponding consumption quantities and then dividing the result by total consumption for that time period and year.

[419] As discussed previously, significant investment in batteries predicted in the status quo could also be driving the peculiar behaviour.

they constrain what would otherwise take place and, in doing so, mask underlying concerns with how the model is operating. One might ask, for instance, how much the prices would move if they were not constrained in these ways. If the answer is 'significantly', then this would potentially be symptomatic of even more problems with the modelling.

Removing the generation price caps and floors leads to some very strange outcomes.[420] For instance, generation investment increases significantly under both the status quo and the proposal (to over $11b in NPV terms). Minimum generation prices drop to less than 10 cents for *all* time periods across all years and backbone nodes. The consumer surplus change if the Authority's proposal is adopted also increases to $2 octillion in NPV terms (i.e. $2 with 27 zeros after it) which, plainly is not a credible number. This all serves to highlight further that the demand modelling included within the grid use model is not robust and cannot be relied upon.

B.5.4 Transmission costs understated

The Authority uses the grid use model to forecast the costs of the additional transmission that would be needed to meet the projected increase in peak demand. It produces an estimate of $188m. However, the adjustments used by the Authority have introduced a downward bias into that estimate.

For the most part, the Authority uses its 'All_major_capex' scenario to estimate the costs and benefits. However, there is one key exception. Rather than adopting the $421m transmission cost estimate from that scenario, the Authority averaged it with the $67m from the low case scenario ('Demand_major_capex') to get $244m, or $188m in estimated transmission costs (once assumed overheads are removed). This unnecessarily understates those costs relative to the grid use and avoided battery investment benefits that were also estimated from the 'All_major_capex' scenario.

The Authority has also assumed that unallocated overheads would stay constant over time, irrespective of the level of direct transmission investment. It is true that some overheads would stay at the same dollar level, irrespective of the level of transmission investment. But that is not the case for all overheads. More transmission investment means more work for HR, IT, procurement and other back-office support functions. Although some functions may have the capacity to ramp-up without additional cost, at some point more work means more staff or external resources (or more overtime) – which comes at a cost.[421] The Authority has not

420 As an illustration, this can be done by taking the 'AoB_All_Major_Capex.py' Python script for the 'all_major_capex' scenario, removing the price cap and floors at lines 416 to 429 and run-running the code. There may be other ways of doing this that better reflect the 'modelling architecture' used by the Authority.

421 By way of example, see the Commission's final determination for Powerco's customised price path application where it allowed an increase in enterprise support costs needed to support its significant step up in direct capital expenditure. See: Commerce Commission, *Powerco's customised price-quality path*, *Final decision*, para.435.

accounted for those additional overhead costs, which has resulted in a further downward bias in its cost estimate.

If the first issue was addressed (i.e., by not incorporating the low case scenario in the derivation of the cost), the transmission cost estimate would increase by \$136m to \$324m. If the second issue was addressed (e.g., by recognising that, say, 50% of the unallocated overheads varied with the level of investment), then that estimate could increase by a further \$48m to \$372m.

Appendix C Problems with the price cap

The Authority has proposed to apply a cap on the annual increases in distributor's and major direct-connect customer's prices.[422] Importantly, the cap would apply only to 'capped transmission charges'. This would represent only a sub-set of *total* transmission charges.[423] Specifically, it would capture primarily any increases in transmission charges arising from the residual charge and the subjection of the seven *existing* investments to BB charges. However, it would not include any price increases arising from:

- any increases in BB charges flowing from transmission investments made *after* the 2019/20 pricing year (i.e., new investments);[424] or
- any increases in BB charges resulting from Transpower deciding to apply the methodology to *more* pre-2019 investments.[425]

In general terms, the proposed cap would function as follows:

- increases in distributor's 'capped transmission charges' would be limited to no more than 3.5% of the estimated total electricity bill of all of the consumers supplied, directly or indirectly, from the distributor's network in the 2019/20 pricing year, increased by the rate of inflation plus the percentage increase in the distributor's load (if any) since the 2019/20 pricing year;[426] and
- for each direct consumer:
  - for the first five years, increases in direct consumer's capped transmission charges would be limited to no more than 3.5% of its total estimated electricity bill in the 2019/20 pricing year, increased by the rate of inflation plus the percentage increase in the direct consumer's load (if any) since the 2019/20 pricing year; and
  - after 5 years, the 3.5% would increase by 2 percentage points per annum (that is, to 5.5%, then 7.5% etc).

The Authority has proposed that these caps would be removed permanently as soon as they no longer limited a customer's capped transmission charges in a pricing year. In other words, as soon as a year went by during which the cap did not bind for a customer, it would be removed forever.[427] In our opinion, there are significant problems with the way in which the proposed price cap has been designed.

422 Proposed TPM guidelines, clause 50.

423 *Op cit.*, clause 49.

424 *Op cit.*, clause 49(d).

425 *Op cit.*, clause 49(e).

426 Third Issues Paper, pp.164-165.

427 Proposed TPM guidelines, clause 50(k).

C.1 The cap provides little protection against price rises

The proposed price caps do very little to protect customers from increases in their *total* electricity bills. Firstly, as we explained above, the cap applies to only a sub-set of transmission charges. It follows that the transmission component of a customer's electricity bill could increase by much more than 3.5% (in real terms) in a year without the cap binding. This is evident immediately in the indicative customer impacts. According to the Authority's calculations:[428]

- half of all distribution businesses would be subject to price shocks ranging up to 98% for Buller Electricity, 101% for Westpower and 107% for Horizon Energy (in year 1); and
- the impacts are even worse for many of the major industrials, e.g., the initial increases for Pan Pacific, NZ Steel, Southdown, Tilt, Norske Skog and Todd Gen. Taranaki range from 138% to 25,231%.

Even on their own terms, these increases would, in our opinion, constitute 'price shocks' under any conventional definition. Moreover, those numbers could also change. For example, if Transpower decided to reallocate more than just the seven existing investments earmarked for BB charges these indicative charges would be affected. Incidentally, there seems to be no logical basis for applying the cap to some existing investments but not to any others that Transpower might choose to revisit.

The proposal could also lead to substantial increases in the *non-transmission* components of customers' bills. For example, we explained in our analysis of the CBA why the proposal would be likely to lead to higher distribution costs (an effect that the Authority chose not to model). Any such increases would flow-through to final prices and would be unaffected by the cap.

The Authority's analysis of wholesale price impacts is also predicated on a model that does not reflect the way in which generator's make investment decisions. There is therefore every chance that spot prices would be *higher* over the long term if the proposal is implemented, which would increase final prices by even more. In short, the proposed cap provides very little protection against price shocks.

C.2 Elements of the cap are problematic

There are several more specific elements of the proposed price cap that are potentially problematic or anomalous. Firstly, customer for whom the cap does not bind that are facing price increases would see their prices go up by *even more* because of its existence. That is a most peculiar result. In our opinion, instead of 'funding' the cap by seeking contributions from all customers for which it does not bind, it would be more sensible to do so solely from parties poised to experience price reductions.

[428] Third Issues Paper, p.61.

There is a handful of customers that are forecast to receive substantial transmission price reductions if the proposal is introduced. For example, Meridian's estimated price cut is $28.7m in the first year and NZAS is anticipated to receive an $11.3m drop. A more orthodox approach would be to spread these reductions out over a longer period and to fund the cap in that way, rather than by piling additional increments onto prices that are already increasing. In other words, those customers that are facing significant price rises should have those increases managed by smoothing out the *reductions* that would accrue to the biggest winners.

Secondly, the 'base year' against which annual increases would be measured (i.e., the 3.5% escalations) is proposed to be the 2019/20 pricing year. That would be the last year of Transpower's second regulatory control period (RCP2). However, the Authority does not expect its proposal would be implemented until 2022 at the earliest, which would be during RCP3. This is significant because:

- there is every expectation that Transpower's regulatory WACC will be lower in RCP3 than in it is currently, due to a significant reduction in the risk-free rate (a final decision is due later this year); and
- all other things being equal, this would increase the absolute size of the price increases that are permitted under the cap that uses 2019 as the base year as opposed to, say, 2022, i.e., 3.5% of a 2019 base price is likely to be *higher*.

Thirdly, the base prices would also include a 5-year weighted average of spot prices. This time period would consequently include the approximately three-month period beginning early October last year, during which wholesale prices increased dramatically above 'normal' levels. For example, average prices were around three times higher than they had been at the same times the prior year. These atypically high prices would therefore serve to increase further the base value from which the cap would be determined, resulting again in a less exacting threshold.

Appendix D Previous reports

The conclusions in this paper have been informed by the analysis and materials contained in earlier papers by Axiom's economists; namely:

- Axiom Economics, Economic Review of Transmission Pricing Supplementary Consultation Paper, A Report for Transpower, February 2017;
- Axiom Economics, Economic Review of Second Transmission Pricing Methodology Issues Paper, A Report for Transpower, July 2016;
- Axiom Economics, Economic Review of Distributed Generation Pricing Principles Consultation Paper, A Report for Transpower, July 2016;
- Green H., Economic Review of TPM Options Working Paper, A Report for Transpower, August 2015;
- Green et al, Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower, March 2014;
- Green et al, Avoided Cost of Transmission Payments, A Report for Vector, January 2014;
- Green et al, Letter to Mr Carl Hansen, Chief Executive, Electricity Authority, Sunk Costs Working Paper, 12 November 2013;
- Green et al, Economic Review of EA CBA Working Paper, A Report for Transpower, October 2013;
- Green et al, Letter to Mr Carl Hansen, Chief Executive, Electricity Authority, Transmission Pricing Conference – Response to Questions, 25 June 2013;
- Green et al, Transmission Pricing Methodology – Economic Critique, February 2013;
- Green et al, Potential Generator Market Power in the NEM, A Report for the AEMC, 22 June 2011; and
- Green et al, New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group, 28 August 2009.

Appendix E Timetable of TPM review

26 Jan 2012	Decision-making and economic framework paper released
10 Oct 2012	First issues and proposal paper – **first methodology proposed (proposal 1)**
29 May 2013	Three-day workshop on TPM proposal – further submissions sought
Aug 2013	Authority announces it will be preparing a second issues and proposal paper in July 2015, and releasing a series of 8 working papers on various topics in the interim to inform that process
3 Sep 2013	Cost benefit analysis working paper
8 Oct 2013	Sunk costs working paper
19 Nov 2013	Avoided costs of transmission payments for distributed generation working paper
21 Jan 2014	Use of loss and constraint excesses working paper & beneficiaries-pay working paper – contained a revised version of the methodology **(proposal 2)**
6 May 2014	Connection charging working paper
29 July 2014	Long-run marginal cost working paper
16 Sept 2014	Problem definition working paper: "what problem have we been trying to solve for that last 2.5 years?"
16 June 2015	Options paper – contained a new methodology **(proposal 3)**
17 May 2016	Second issues paper – contained another new methodology **(proposal 4)** and a cost benefit analysis (CBA) prepared by Oakley Greenwood (OGW)
29 July 2016	Trustpower launches judicial review of the AUTHORITY's decision to not grant an extension to the submission deadline, arguing that the process had "gone off the rails"
2 Dec 2016	High court declines Trustpower's judicial review – stating that it is too early to know if any *"flaws in the process are irretrievable"*
13 Dec 2016	Supplementary consultation on second issues paper and CBA – some minor changes made to proposed methodology and to CBA
10 Mar 2017	Cross-submissions on asset valuation (first cross-submission round in the process)
23 Mar 2017	Revised CBA issued to address significant errors identified in submissions; online question and answer session held
26 April 2017	Authority acknowledges that OGW's analysis is fatally flawed and announces that it is starting the CBA again
8 July 2019	Authority delays the release of its third issues paper to address a potential error
23 July 2019	Third issues paper – containing another proposal and another CBA **(proposal 5)**

TRANSPOWER

Keeping the energy flowing

Attachment B Proposed TPM Guidelines: Clause-by-clause Commentary

- For each clause we provide comment directly against each clause where relevant.
- For clauses 17, 18, 25, 26, 32(b) and (to the extent it applies to benefit-based charges) 42, we propose redrafts under clauses XA, XB and XC following the table.

Proposed TPM Guidelines – 2019 Issues Paper	**Transpower comment:**
Policy objectives	This section of the guidelines is descriptive of the charges rather than illuminative of any over-riding policy objectives. It is also unclear whether this section is intended to be an operative part of the guidelines (for example, it is not referred to in clause 3). This section does not help with interpreting anything later in the guidelines, and contains some inconsistencies with the later requirements. We think this section should be deleted.
The Electricity Authority (the **Authority**) has reviewed the guidelines which Transpower is required by the Electricity Industry Participation Code 2010 (the **Code**) to follow in developing a proposed transmission pricing methodology (**proposed TPM**) (the **Guidelines**). Having undertaken this review, the Authority considers that, in order to allow Transpower to recover up to its forecast maximum allowable revenue in any year and to better meet the Authority's statutory objective, the proposed TPM should contain the following components: (a) a connection charge; (b) a benefit-based charge; (c) a residual charge; (d) a prudent discount policy; (e) a cap on transmission charges; and	See our comment on clause 54 about the additional components being discretionary rather than mandatory (which is relevant to the words "are to" in subclause (f)).

(f) seven additional components which are to be implemented if they better achieve the Authority's objective.	
Connection charge The purpose of the connection charge is to charge each designated transmission customer to recover the cost of the assets that connect it to the interconnected grid.	
Benefit-based charge The purpose of the benefit-based charge is to recover the costs of new and certain existing investments in the interconnected grid (including investments in transmission alternatives). The charge is to be allocated between designated transmission customers in accordance with the estimated positive net private benefits that each transmission customer is expected to receive from the investment (or a proxy for these benefits). The positive net private benefit of the transmission customer includes the positive net private benefit of any parties that are connected to the interconnected grid through the transmission customer.	
Residual charge The purpose of the residual charge is to provide a mechanism to ensure that Transpower is able to recover up to its forecast maximum allowable revenue in any year in a way which does not affect designated transmission customers' decision-making.	The RCP3 IPP will smooth Transpower's revenue over the five years of the regulatory period. Our annual revenue cap will be smoothed maximum allowable revenue (SMAR) rather than maximum allowable revenue (MAR). We have suggested a new defined term of "maximum revenue" to deal with this and provide flexibility for RCP4 and beyond (see clause 66). We suggest that all references in the guidelines to "forecast MAR" be replaced with "maximum revenue". The residual charge is not 100% incentive-free. Whether or not the residual charge affects customers' decision-making remains to be seen. The words "does not affect" should be replaced with "is designed to not affect".

Prudent discount policy The purpose of the prudent discount policy is to allow Transpower to discount the transmission charges of a designated transmission customer who otherwise would find it viable to inefficiently bypass the grid (including inefficiently disconnecting from the grid in favour of alternative supply).	
Cap on transmission charges The purpose of the cap on certain transmission charges is to minimise price shock by limiting the total increase in transmission charges relating to the existing interconnected grid that each load customer faces relative to the charges that the customer actually pays for the existing interconnected grid in the 2019/20 pricing year. The cap applies only as long as it is effective in limiting a designated transmission customer's transmission charges subject to the price cap as set out in clause 49.	In our view, the policy objectives section (if retained) should not refer to the detailed rules later on in the guidelines. The words "as set out in clause 49" should be deleted.
Additional components Transpower would include each additional component in the TPM if doing so would better achieve the Authority's statutory objective.	See our comment on clause 54 about the additional components being discretionary rather than mandatory. There is inconsistent wording in the guidelines as to the threshold for Transpower including additional components. In this clause the threshold is "would better achieve", which is an objective threshold. In clause 54 the threshold is "would, in Transpower's reasonable opinion, better meet", which is a subjective threshold. In the definition of "additional component" in clause 66 there is a different subjective threshold, namely "where Transpower considers...will better meet". These thresholds should be consistent, and in our view should be "Transpower considers".
(a) Staged commissioning. The purpose of this component is to allow Transpower to adjust how it recovers the cost of an investment that is commissioned in stages, so the charges better reflect the positive net private benefits it provides.	In our view this additional component should be deleted. See our comment on clause 55.

(b)	Assets that in substance provide connection services. The purpose of this component is to ensure that if a connection asset that continues in substance to provide principally connection services is reclassified as an investment in the interconnected grid, it is still charged for as a connection asset.	We do not agree with how this additional component is worded. See our comment on clause 56.
(c)	Charges for connection assets. The purpose of this component is to allocate connection charges in substantially the same way as benefit-based charges.	In our view this additional component should be deleted. See our comment on clause 57.
(d)	Transitional peak charge. The purpose of this component is to efficiently influence grid use at peak times for a limited transitional period, if nodal prices are not adequate to meet this objective.	The test in this subclause only refers to nodal prices, whereas the test in clause 59 refers to "other prices including nodal pricing". Both are inconsistent with the definition of "peak charge" in clause 66, which refers to "nodal prices and the other transmission charges". In this clause and clause 59 the threshold is that nodal prices are "not adequate" to influence grid use at peak times. In our view that threshold is slanted unduly against a peak charge. The test for whether a peak charge should be retained, permanently or under transitional arrangements, should be expressed in neutral terms focussing on whether the peak charge would deliver benefits, not on the relative efficacy of the peak charge versus nodal prices. See also our comments on clauses 58 to 61.
(e)	Extension of benefit-based charge. The purpose of this component is to allow Transpower to extend the benefit-based charge to further pre-2019 investments.	
(f)	Opex. The purpose of this component is to attribute opex to the investment or asset that it is spent on without recourse to proxies.	The use of the word "investment" in the guidelines is confusing. Sometimes it refers to a project and sometimes it refers to an asset (i.e. the output of a project). In this paragraph it is unclear exactly how or why the "investment" is being distinguished from the "asset". See our comment on clause 12.

(g)	kvar charge. The purpose of this component is to allow Transpower to impose a charge on reactive power.	

	General matters	
1.	In developing the **TPM** in accordance with these **Guidelines**, Transpower must, as far as reasonably practicable:	
	(a) set charges in a way that reflects: (b) the cost of providing designated transmission customers with: A. new investment in the grid; B. access to the parts of the grid relevant to them; and C. use of the grid to transport energy; (ii) the **positive net private benefits** those designated transmission customers derive from those things;	There is something wrong with the subclause nesting here. We think subclause (b) should be subclause (i). Even with that change subclause (a)/(b) is confusing. It is not clear how or if this subclause allows us to depart from the requirements later in the guidelines on reasonable practicability (workability) grounds. We suggest subclause (b) be deleted and the concept of reasonable practicability departures be incorporated in clause 2. See our proposed alternative drafting below for clause 2. We note that while these subclauses provide that charges should be set on the basis of cost, they also require that charges be set on the basis of benefit. These are competing and potentially contradictory concepts. The cost of providing a service is not the same as the benefit (or benefit share) a customer receives from the service. "Designated transmission customer" is a Code-defined term but is not underlined in subclause (b). The guidelines need to be checked for appropriate underlining and bolding of defined terms, as there are some other examples of this.
	(c) balance the economic benefits and costs of precision of the **TPM** with the economic benefits and costs of practical considerations including:	This subclause implies a formal cost-benefit balancing exercise, which we will not necessarily carry out. The introductory wording should be "Take into account practical considerations including:".

	(i) robustness; (ii) simplicity; (iii) certainty, including through limiting the need for Transpower to exercise a discretion; and (iv) costs associated with developing, administering and complying with the **TPM**;	
	(d) avoid creating incentives for existing and potential designated transmission customers to avoid **transmission charges** in ways that cause economic inefficiency;	In our view this clause should be deleted. See our comment on clause 42(c). We note that if the guidelines contain efficient charges and efficient pricing signals then incentives to avoid those charges will enhance efficiency rather than cause inefficiency. In that sense this clause assumes the design of the charges is inefficient in some way and needs to be mitigated.
	(e) avoid creating incentives for distributed generators to seek avoided cost of transmission payments, except to the extent that the payments reflect a saving in the costs of transmission (not just a saving in **transmission charges** to the relevant distributor);	This is a matter for Part 6 of the Code, not for the TPM or guidelines. We note that the Authority has proposed a Code amendment to address this.
	(f) avoid discriminating between designated transmission customers, except to the extent necessary to achieve the Authority's statutory objective; and	The words "necessary to achieve the Authority's statutory objective" should be "allowed by these Guidelines". The guidelines contain many ways in which we are required to discriminate between our customers, which may or may not be justified by the statutory objective. For example, the benefit-based charge requires that if one customer receives greater benefits than another for the same service, even if they both cost the same to supply, the former customer should be charged more.
	(g) allow Transpower to recover its **forecast MAR**, should it wish to do so.	

2.	Transpower may propose a **TPM** which differs in its details from the particular requirements in the **Guidelines**, if it considers, in its reasonable opinion, that doing so would better meet the Authority's statutory objective than complying with the **Guidelines** in their entirety.	The words "details" and "particular requirements" introduce uncertainty as to how far our discretion goes. These qualifiers should be removed. Our proposed alternative drafting is below, and would also replace clause 1(a)/(b) as per our comment on that clause above. This redrafting would require consequential changes to clause 4(a). *2. The **TPM** may differ from any requirement in these **Guidelines** to the extent Transpower considers:* *(a) it would better meet the Authority's statutory objective for the **TPM** to differ from the requirement than to comply with it; or* *(b) it would not be reasonably practicable for Transpower to comply with the requirement.* As with the threshold for incorporating the additional components, there is inconsistent wording in the guidelines as to the threshold for Transpower departing from the guidelines. In this clause the threshold is "considers, in its reasonable opinion…would better meet". In clause 15(b) the threshold is "would better meet". In clause 40(b) the threshold is "consider…would better meet". In clause 60(b) the threshold is "would, in Transpower's reasonable opinion, better meet". These thresholds should be consistent, and in our view should be "Transpower considers". There is also inconsistent use of "the Guidelines" versus "these Guidelines" in this clause and elsewhere.
3.	All subsequent provisions in these **Guidelines** are to be interpreted and applied subject to clauses 1 and 2 above.	
4.	In developing the **TPM**, Transpower must prepare an outline of Transpower's reasons for proposing the particular methods it has included in the **TPM**, to be provided to the Authority along with the **TPM**. This outline must include details of:	Clause 4 is not a guideline for the TPM. It would be more appropriate to cover this outside the guidelines as a process requirement.

	(a) where, under clause 2, Transpower proposes a **TPM** which differs in its details from the particular requirements of the Guidelines, how the **TPM** differs from the **Guidelines** and Transpower's reasons for proposing a **TPM** which differs from the **Guidelines**, including why it considers that its proposed **TPM** better meets the Authority's statutory objective; and	
	(b) where Transpower has made an assumption in developing the **TPM**, the assumption made and Transpower's reasons for making that assumption.	This requirement should be limited to *material* assumptions. Same for clause 5(e), if retained.
5.	The **TPM** must include requirements for Transpower to consult on: (a) the proposed **benefit-based charge** and its allocation between designated transmission customers for each proposed **high-value benefit-based investment**; (b) the proposed allocation of the **residual charge**;	
	(c) important parameters used to calculate those charges and allocations;	This requirement is unnecessary as the important parameters (and assumptions referred to in subclause (e)) will naturally be part of the benefit-based and residual charge consultations.
	(d) any proposed material changes to those charges or allocations (in which case consultation must extend to whether such changes are warranted by a change in circumstances); and	We should not have to consult on a change to the total residual charge as it is a wash-up. "Change in circumstances" is odd wording because that is not a threshold in the guidelines for reopening the charges. In our view the words in brackets are unnecessary.
	(e) any assumptions made in calculating those charges, allocations or material changes to those charges or allocations,	See our comments on subclause (c) and clause 4(b).
	with parties who have a material financial interest in the charges. Where Transpower can demonstrate that such parties have already	

	been consulted on the above (whether by Transpower or any other party), it need not repeat that consultation for the purposes of this clause.	
6.	The **TPM** must include a requirement for Transpower to provide each designated transmission customer with information regarding how its **transmission charges** have been calculated, including the basis on which its **benefit-based charge** and **residual charge** have been set. The basis on which the **residual charge** has been set includes the extent to which the **residual charge** comprises unallocated **opex** and the extent to which it comprises costs which have been reallocated to the **residual charge** as a result of **benefit-based investments** having been subject to **reassignment**. Information provided for the purposes of this clause should be sufficient to enable the designated transmission customer to verify the accuracy of Transpower's calculations of its **transmission charges**.	Clause 6 is not a guideline for the TPM. It would be more appropriate to cover this outside the guidelines, perhaps as a change to clause 41 of the benchmark agreement/transmission agreements. It is not stated how often we are required to provide the information. Is it annually? The requirement in the final sentence of this clause is too high a standard and should be deleted. The information we provide will not necessarily allow for a complete independent recalculation of transmission charges.
7.	The **TPM** must provide that, where it is necessary to consider the characteristics of, benefits or costs accruing to, or incentives on, a designated transmission customer under the **TPM**, that assessment must also consider the characteristics of, benefits or costs accruing to, or incentives on any parties directly or indirectly electrically connected to that designated transmission customer.	Parties are not electrically connected to designated transmission customers, rather it is their respective plant that is connected.
8.	The **TPM** must provide for the treatment of a transmission alternative to be consistent with the treatment the investment which the transmission alternative seeks to avoid would have received under these **Guidelines** or, where this is not reasonably practicable, for the cost of transmission alternatives to be allocated to the designated transmission customers that benefit from them in proportion to the relative level of benefit that each customer receives.	The last part of this clause (from "or") is unnecessary. In any event, the reference to "benefit" should be "positive net private benefit".

	Main components	
9.	The **TPM** must include: 1. a charge for **connection assets**; 2. a **benefit-based charge**; 3. a **residual charge**; 4. a prudent discount policy; and 5. a cap on specified **transmission charges**. The total recovered by Transpower under these components may not exceed Transpower's **forecast MAR**.	The fifth item in this list is incomplete because, as proposed, the cap will only last for a limited period. In the last sentence "total" should be "total revenue".

	Main component 1: connection charge	
10.	The **TPM** must provide for the costs of **connection assets** to be recovered from those connected to them.	
11.	The **TPM** must include a definition of deep connection, which must be applied consistently and transparently. The definition of deep connection must avoid subsidisation of interconnection assets to the extent reasonably practicable.	

	Main component 2: benefit-based charge	
	Benefit-based charge must apply to benefit-based investments	
12.	The **TPM** must include a **benefit-based charge** for each **benefit-based investment**.	The benefit-based charge needs to be calculated and allocated by reference to a particular asset or assets, but it is said to be "for each benefit-based

		investment". A problem arises because the "investments" listed in clause 13 (which defines "benefit-based investment") are not assets. They are projects. One way of fixing this is to amend the definition of "benefit-based investment", as suggested below (clause 66). If that change is made, then all references to "assets comprising the benefit-based investment" or similar (e.g. clauses 14(a)(ii) and 16) can be replaced with just "benefit-based investment".
13.	A **benefit-based investment** means:	
	(a) any **post-2019** investments in the **interconnected grid**, including any <u>transmission alternatives</u>;	We understand that the purpose of clause 8 is to deal with the treatment of transmission alternatives in a global way rather than on a clause-by-clause basis, as is done here. The danger of the clause-by-clause approach is that not all relevant clauses are captured. We recommend retaining clause 8 and deleting the references to transmission alternatives elsewhere. Also, it is possible for there to be a transmission alternative for a connection asset investment, so "any transmission alternatives" in this clause is wrong.
	(b) the following **pre-2019** investments in the **interconnected grid:** (i) the Bunnythorpe-Haywards Reconductoring Project (ii) investments in and associated with the <u>HVDC link</u> (iii) the Lower South Island Renewables Project; (iv) the Lower South Island Reliability Project; (v) the North Island Grid Upgrade (NIGU) Project; (vi) the Upper North Island Dynamic Reactive Support Project; and (vii) the Wairakei Ring Project;	

	(c) **upgrading expenditure** as provided for in clauses 30 to 32 below; and	
	(d) **pre-2019** investments in the **interconnected grid** identified by means of a method established under clauses 62 and 63 below.	
	Benefit-based charges must recover the covered cost of benefit-based investments	
14.	The **benefit-based charge** for a **benefit-based investment** must recover, over the **benefit-based investment's remaining life**, the present value of the **covered cost** of that **benefit-based investment**, which comprises:	This will not be true if the benefit-based investment is subject to reassignment. This may not be true if: - a simple method is used to allocate the benefit-based charge (see our comment on clause 23(c)); - the investment is a reliability investment required to satisfy the deterministic limb of the grid reliability standards and has negative net benefits (because in that case there may not be any positive net private beneficiaries to allocate the charge to); - the investment is a previously economic investment that has become uneconomic over time (for the same reason); or - the investment is an enabling investment with no positive net beneficiaries initially. In relation to the second, third and fourth points, while the guidelines may now avoid the "no beneficiaries" problem for NAaN and the other two omitted historical investments, the problem still potentially arises for post-2019 investments. What happens if there are no positive net private beneficiaries for a post-2019 investment? Does the covered cost go into the residual charge until at least one beneficiary can be identified?

	(a) the capital cost of the **benefit-based investment**, based on: (i) for **post-2019 benefit-based investments**, the **value of commissioned assets** forming part of that **benefit-based investment**; (ii) for **pre-2019 benefit-based investments**, the depreciated value of the assets comprising the **benefit-based investment** as recorded in the **regulatory asset base** at the date the **benefit-based charge** is first applied to the **benefit-based investment**;	
	(b) a return on capital for the **benefit-based investment**, based on its capital cost as allowed for under paragraph (a) and **WACC**;	
	(c) an amount of forecast **opex** reasonably attributable to the benefit-based investment based on an allocation of the **opex** allowance for the **pricing year** as set by the Commerce Commission in the **IPP**; and	The Commerce Commission reference is unnecessary given the definition of "IPP".
	(d) any other costs attributable to that **benefit-based investment**.	"Costs" should be "forecast costs".
	Recovery of the covered cost of a benefit-based investment over time	
15.	The **TPM** must provide for the **annual benefit-based charges** for each **post-2019 benefit-based investment** to be calculated: (a) using the following method: (i) the expected **benefit-based charge** for the **benefit-based investment** is divided into equal annual amounts over the **benefit-based investment's remaining life**; and	In subclause (a)(i) "expected" is unnecessary. It should be discretionary, not mandatory, for Transpower to use an alternative method for calculating the annual charges. Our proposed alternative drafting for subclause (b) (which would be in a separate clause) is as follows: *15A The **TPM** may provide for the **annual benefit-based charges** for a **post-2019 benefit-based investment** to be calculated using an alternative method if:*

	(ii) the annual amounts determined under subclause (a)(i) are adjusted for inflation over the **benefit-based investment's remaining life** using an index determined by Transpower; or (b) according to an alternative method, where that alternative method: (i) would better meet the Authority's statutory objective than the method described in paragraph (a); and (iii) would still recover the **covered cost** of that **benefit-based investment**.	*(a) Transpower considers that the alternative method would better meet the Authority's statutory objective than the method in clause 15; and* *(b) the alternative method fully recovers the* ***covered cost*** *of the* ***benefit-based investment****.* As commented on clause 14, subclause (b) of this alternative drafting may not always be true.
16.	The **TPM** must provide that Transpower's recovery of the capital components for each **pre-2019 benefit-based investment** for a **pricing year** under the **TPM** must be the same as the forecast depreciation and forecast capital charge in that **pricing year** for the assets of that **benefit-based investment** under the **IPP**.	We assume that the recovery profile for elements of the covered cost other than the capital component is intended to be at our discretion. Replacing the words "capital charge" with "return on capital" would be consistent with clause 14(b).
17.	The **TPM** must allow Transpower to adjust future **annual benefit-based charges** for a **benefit-based investment** if, in Transpower's reasonable assessment, there has been, or will be, a material change to any of the expected future: (a) **WACC;** (b) **opex** attributable to the **benefit-based investment;** (c) **remaining life** of the **benefit-based investment;** or (d) any other costs attributable to the **benefit-based investment.**	We suggest that this clause and clauses 18, 25, 26, 32(b) and (to the extent it applies to benefit-based charges) 42 be replaced with new combined (and simplified) clauses so that changes affecting benefit-based charges are dealt with in one place. See our proposed alternative drafting for those clauses below (clauses XA to XC). One of the changes in the alternative drafting is removing "expected future" because the charges should not change before the change to the relevant input actually happens (although we will prepare for the input change if we know about it in advance). In subclause (b) "opex" should be "forecast opex", and in subclause (d) "costs" should be "forecast costs".

	The **benefit-based charge** must recover the present value of the **covered cost** of each **benefit-based investment**.	This is already stated in clause 14. As commented on clause 14, this statement may not always be true.
	Damage to a benefit-based investment	
18.	The **TPM** must allow Transpower to adjust or end future **annual benefit-based charges** for a **benefit-based investment** where an asset or assets forming part of that **benefit-based investment** are destroyed or substantially damaged.	See our comment on clause 17, which proposes deleting this clause, and proposed alternative drafting below (clauses XA to XC). Decommissioning should also be covered.
	Allocating annual benefit-based charges among customers	
19.	The **TPM** must include one or more standard methods for allocating **annual benefit-based charges**.	It is more correct to say that the methods allocate the benefit-based charges. The annual benefit-based charges are then a product of that allocation.
20.	The **TPM** may include one or more simple methods for allocating **annual benefit-based charges**.	
21.	The **TPM** must provide: (a) that Transpower must use a standard method to allocate **the annual benefit-based charges** for **high-value post-2019 benefit-based investments**; (b) that Transpower must use Schedule 1 to allocate the **annual benefit-based charges** for the **benefit-based investments** included in Schedule 1; (c) where these **Guidelines** provide for an adjustment to the Schedule 1 allocations, a method for making that adjustment. That method must be a standard method, simple method or combination of both; and	In relation to subclause (b), we note that none of the allocations in Schedule 1 add up to exactly 100% for the relevant investment due to rounding (the totals range from 99.96% to 100.02%). That needs to be fixed or else there will be an over or under-recovery of benefit-based charges. There is no equivalent of clause 41 for the allocations in Schedule 1, meaning that material changes in the distribution of net private benefits for the historical investments between the time the new Guidelines are published and the time the benefit-based charges first appear in transmission prices are not captured. We are obliged to use the Schedule 1 allocations initially even if they are clearly wrong.

	(d) that Transpower must use a standard method, simple method or combination of both to allocate the **annual benefit-based charges** for any other **benefit-based investments**.	
22.	A standard method: must allocate the **annual benefit-based charge** for a **benefit-based investment** between the designated transmission customers expected to benefit from the **benefit-based investment** in proportion to their expected **positive net private benefit** from the **benefit-based investment** over its **remaining life**; where necessary, may determine expected **positive net private benefits** using one or more reasonable proxies. Such proxies must, in Transpower's reasonable opinion, result in an allocation of the **benefit-based charge** to each designated transmission customer who receives a major **positive net private benefit** from the **benefit-based investment** that broadly approximates the allocation that Transpower considers would have resulted had expected **net private benefits** been used to calculate the allocation.	The last sentence of subclause (b) is unnecessary. "Proxy" means an approximation. The sentence also suggests we have to carry out another net private benefit calculation to cross-check the proxies, which we should not have to do. Also, it is likely all standard methods will use proxies of some sort, in which case there will not be a "true" source of net private benefit information to compare to.
23.	A simple method: (a) must be capable of being implemented at a lower cost to participants, including Transpower, than the standard method(s). Cost includes administrative burdens on participants but does not include increases in resulting **transmission charges;** (b) must, in Transpower's reasonable opinion, result in an allocation of the **benefit-based charge** to the designated transmission customers who receive a major **positive net private benefit** from the **benefit-based investment** that broadly approximates the allocation that Transpower considers would have resulted had the standard method been applied. However, Transpower is	Subclause (b) should refer to "a standard method" as there may be more than one. In relation to subclause (c), if a non-major beneficiary is exempted, does that beneficiary's share go to the major beneficiaries or into the residual? If the latter, this will be an exception to the rule that the benefit-based charge must fully recover the covered cost of the relevant investment.

	not required to apply the standard method solely for the purpose of making this assessment; and (c) may exempt designated transmission customers who do not receive a major **positive net private benefit** from a **benefit-based investment** from receiving an allocation of the **annual benefit-based charges** for the **benefit-based investment**.	
24.	The **TPM** must provide that, save for benefits and costs included at Transpower's discretion, the treatment of benefits and costs used to calculate **net private benefits**, to the extent applicable, in respect of **post-2019 benefit-based investments** under each standard method and each simple method must be consistent with, though not necessarily identical to, the treatment of the relevant **electricity market benefit or cost elements** under the test used by the Commerce Commission in its approval of the **post-2019 benefit-based investment**, unless Transpower considers there has been a material change since that test was applied.	There are potentially material differences in the way net private benefits would need to be calculated compared to the assessment of electricity market benefits and costs under the Commerce Commission's investment test. For example, under the investment test we use a "no NZAS" scenario. Application of that scenario to the net private benefit calculation would result in a zero benefit for NZAS under the scenario, and bias downwards NZAS' share of the relevant benefit-based charge. We note that the investment test does not apply to our base capex investments.
25.	The **TPM** must provide that, once a designated transmission customer's share of the **annual benefit-based charge** has been allocated, that share will not change, save where these **Guidelines** permit otherwise.	See our comment on clause 17, which proposes deleting this clause, and proposed alternative drafting below (clauses XA to XC). In our view there is a fundamental contradiction in having a beneficiaries-pay charging regime with fixed or pseudo-fixed charges. Over time this will mean the charges will not reflect reality (the actual benefits customers receive) and the regime will not be durable.
26.	The **TPM** must provide: (a) that Transpower may review the allocation of future **annual benefit-based charges** for a **high-value benefit-based investment** if Transpower considers there has been, or expects that there will be, a substantial and sustained change in grid use affecting the **net private benefits** derived by one or more	See our comment on clause 17, which proposes deleting this clause, and proposed alternative drafting below (clauses XA to XC). In our view the qualifier "were not factored into" in subclause (b) is not appropriate because a substantial change in probability is still a substantial change. For example, a probability change from 1% to 100% should not be treated differently to a probability change from 0% to 100%. What matters is that the allocation of a benefit-based charge reasonably accurately reflects

	designated transmission customers from the **benefit-based investment**; (b) that a substantial change in grid use will only have occurred where the circumstances which have eventuated were not factored into the calculations used to allocate the relevant charges; (c) a method for Transpower to determine whether there has been a substantial and sustained change in grid use affecting a **high-value benefit-based investment**; and (d) a method/s for adjusting allocations in the event that there has been a substantial and sustained change in grid use.	positive net private benefits arising from the relevant investment. That may not be the case regardless of whether the future circumstances were factored into the initial allocation. Subclauses (c) and (d) are unnecessary. The TPM will include methods for everything required by the guidelines.
	Implementation timeframe for the benefit-based charge	
27.	The **TPM** must provide for the **benefit-based charge** to apply to **high-value post-2019 benefit-based investments** and **pre-2019 benefit-based investments** to which Schedule 1 applies from the commencement of the **TPM** or the date on which the investment is **commissioned** (whichever is later).	
28.	The **TPM** must provide for **benefit-based charges** for **low-value post-2019 benefit-based investments** to be phased in as soon as is reasonably practicable after the **benefit-based charge** has been applied to the **high-value benefit-based investments** listed in clause 27 and no later than five years after the commencement of the **TPM**.	"Listed in" should be "referred to in".
29.	The **TPM** must provide that the implementation of **additional components**, other than a transitional **peak charge**, must be deferred if necessary in order to expedite the implementation of the **benefit-based charge** for **high-value benefit-based investments**.	

	Upgrading expenditure	
30.	**Upgrading expenditure**, in relation to existing **benefit-based investments**, means expenditure that results in an extension to the existing **benefit-based investment's remaining life** or otherwise increases the benefits that **benefit-based investment** is expected to provide.	
31.	The **TPM** must provide that, where Transpower undertakes **upgrading expenditure**, that **upgrading expenditure** must be recovered using the method prescribed in these **Guidelines** for recovering the **covered cost** of a **post-2019 benefit-based investment** having a capital cost equal to the cost of the **upgrading expenditure**.	
32.	Subject to clause 31, in recovering **upgrading expenditure** on existing **benefit-based investments**, Transpower may: (a) treat the **upgrading expenditure** as a new **benefit-based investment**; or (b) adjust as appropriate the value of the **benefit-based investment**, its **remaining life**, its estimated benefits and the calculation and allocation of the **annual benefit-based charge** for it, in order to reflect the changes caused by the **upgrading expenditure**. An adjustment under this paragraph may alter the covered cost and allocation for the overall **benefit-based investment** (comprising the initial **benefit-based investment** and the **upgrading expenditure**). However, such an adjustment is not to alter the requirement to recover the covered cost of the initial **benefit-based investment** or the calculation of **net private benefits** for the initial **benefit-based investment**.	In relation to subclause (b), see our comment on clause 17, which proposes deleting this subclause, and proposed alternative drafting below (clauses XA to XC).

	Reassignment	This section is about optimisation, but without using that word. We do not agree with reassignment/optimisation. See our answer to the Authority's question 26. As an alternative to reassignment/optimisation, we have suggested some drafting below that allows for the benefit-based charge for a high-value benefit-based investment to be reduced so that it is not greater than the total net private benefits arising from the investment (clause XB(d)).
33.	The **TPM** must provide for a party to make an application to <u>Transpower</u> for **reassignment** of charges: (a) where that party has a direct or indirect financial interest in the **annual benefit-based charge** for that **benefit-based investment**; (b) where the **benefit-based investment** had an initial value of $5 million or more (with this threshold to be adjusted for inflation); and (c) whether or not the **benefit-based investment** has previously been subject to **reassignment**.	The words "direct or indirect financial interest" in subclause (a) capture too many potential applicants, such as individual consumers and shareholders. In our view only designated transmission customers that pay for the relevant investment should be able to apply. The threshold of $5 million in subclause (b) is too low, especially as it is an initial value. In our view the threshold should be based on the depreciated value of the investment and be increased to $20m (consistent with the definition of "high-value").
34.	The **TPM** must provide that a **benefit-based investment** must, and may only, be subject to **reassignment** if <u>Transpower</u> considers that the circumstances which led to the **reassignment** are likely to be sustained and: (a) for a **pre-2019 benefit-based investment**, the investment's value following **reassignment** would be less than 80% of its current value; (b) for a **post-2019 benefit-based investment**: (i) where the disconnection of a single party causes the **benefit-based investment's** value following	80% of current value is an arbitrary threshold. Also, we will need to carry out the optimisation exercise to determine whether the 80% threshold is met, so this is not an effective screening mechanism in terms of avoiding the administrative burden. The single party requirement for post-2019 investments in subclause (b) is another arbitrary threshold. It is also unclear whether this threshold would be met if a customer did not completely disconnect from the grid (or from another network, assuming subclause (b) is intended to capture other networks, which is unclear).

	reassignment to be less than 80% of its current value; or (ii) the **benefit-based investment** has been **commissioned** or otherwise been in operation for the period of time specified in the **TPM** for the purpose of this subclause and its value following **reassignment** is now less than 80% of its current value.	
35.	In setting a period of time for which a **post-2019 benefit-based investment** must have been **commissioned** in order for it to be eligible for **reassignment**, the **TPM** must provide for that period to be sufficiently long that the prospect of **reassignment** will likely have a negligible impact on the characteristics of the **post-2019 benefit-based investment** that designated transmission customers are incentivised to seek.	
36.	The **TPM** must include a method for determining the value of a **benefit-based investment** following **reassignment** which is consistent with the revision to forecast future demand for **transmission lines services** which gave rise to the **reassignment**.	
37.	The **TPM** must provide that, where Transpower determines that the circumstances which led to the **reassignment** no longer exist, it must reverse the **reassignment** (that is, restore the value of the **benefit-based investment** to the value that would have applied if the **reassignment** had not taken place) or adjust the level of the **reassignment**, as is appropriate.	Do we have to continually monitor this or is it by application (as the original optimisation would have been)? If by application, who can apply?
38.	The **TPM** must provide that, where Transpower determines to carry out **reassignment** with respect to a **benefit-based investment** or reverse a **reassignment**, it must:	

	(a) modify the **annual benefit-based charge** for that investment to take into account the change in the **benefit-based investment's** value**;** (b) adjust the allocation of the **annual benefit-based charge** to designated transmission customers to the extent necessary to take into account the change in forecast future demand for **transmission lines services** which led to the **reassignment** or reversal of the **reassignment**; and (c) adjust the **residual charge** as necessary to take into account the changes to the **annual benefit-based charge.**	

Transpower comment:

Clauses XA, XB and XC are proposed to replace clauses 17, 18, 25, 26, 32(b) and (to the extent it applies to benefit-based charges) 42. Refer to our comments on each of those clauses.

We have suggested two drafting options for proposed clause XC (reallocating benefit-based charges). The first version reflects the Authority's proposed re-openers with some recommended improvements. The second, shorter, version is an option for simplifying how the guidelines deal with triggers for reallocation. In our view the Guidelines should adopt the principle that the allocation of a benefit-based charge may change whenever there is a material misalignment between net benefits and the allocation, regardless of the cause of that.

Changes to benefit-based charges and allocations

*XA. The **TPM** must provide that:*

*(a) a **benefit-based charge** must not change except as specified in clause XB; and*

*(b) the allocation of a **benefit-based charge** must not change except as specified in clause XC.*

*XB. Transpower may change or end future **annual benefit-based charges** for a **benefit-based investment** if:*

*(a) Transpower considers there has been a material change to the **covered cost** or **remaining life** of the **benefit-based investment** (including due to **upgrading expenditure**);*

*(b) the **benefit-based investment** has been decommissioned, destroyed or substantially damaged;*

*(c) the **benefit-based investment** is subject to **reassignment**; or*

*(d) for a **high-value benefit-based investment**, Transpower considers the **annual benefit-based charges** need to decrease or end so that the total future **annual benefit-based charges** for the **benefit-based investment** does not exceed total **positive net private benefits** to be derived from the **benefit-based investment** over its **remaining life**.*

*XC. Transpower may change the allocation of future **annual benefit-based charges** for a **benefit-based investment** if:*

*(a) new **large plant** connects directly or indirectly to the grid affecting the **positive net private benefits** derived from the **benefit-based investment**;*

*(b) there is a substantial and sustained increase in existing **large plant's** electricity generation or electricity consumption affecting the **positive net private benefits** derived from the **benefit-based investment**;*

*(c) the **positive net private benefits** derived from the **benefit-based investment** are affected by a new direct connection to the grid by a new or existing designated transmission customer, other than in the circumstances described in subclause (a);*

*(d) the **positive net private benefits** derived from the **benefit-based investment** are affected by a designated transmission customer ceasing to have a direct connection to the grid at one or more of its points of connection;*

*(e) for a **high-value benefit-based investment**, Transpower otherwise considers there has been a substantial and sustained change in grid use affecting the **positive net private benefits** derived from the **benefit-based investment**; or*

*(f) a designated transmission customer that is allocated the **benefit-based charge** sells part of its business.*

[or]

*XC. Transpower may change the allocation of future **annual benefit-based charges** for a **benefit-based investment** if Transpower considers the current allocation of the **annual-benefit based charges** does not reflect the **positive net private benefits** derived from the **benefit-based investment**, to a material extent.*

	Main component 3: residual charge	
39.	The **TPM** must provide for **a residual charge** to apply to all designated transmission customers to the extent that they are load to recover any remaining **forecast MAR** not recovered through other **transmission charges**.	"Are load" should be "consume electricity". See our comment on clause 41.
40.	The **TPM** must provide for the **residual charge** to be allocated: (a) in proportion to each designated transmission customer's historical anytime maximum demand, which is to be calculated using data supplied by the reconciliation manager and by: (i) taking, in a **pricing year**, the highest value for any trading period which represents the sum of: A. the highest net quantity of electricity flow from the grid at the designated transmission customer's grid exit point; and B. Transpower's estimate of any concurrent generation by distributed generators or behind-the-meter generation that is indirectly connected to the grid through the designated transmission customer; and (ii) taking the average of that value over at least two years ending prior to either 1 July 2019 or the date 10 years prior to the date on which the **residual charge** is to be assessed, whichever is the later; or (b) by an alternative method of allocating the charge to designated transmission customers to the extent that they are load, should Transpower consider that the alternative method would better meet the Authority's statutory objective than the method set out in paragraph (a) above.	In relation to subclause (a)(i)(A), what happens if the customer has more than one GXP? Are there to be separate allocations of the residual charge for each GXP? In our view the term "behind-the-meter generation" used in subclause (a)(i)(B) should be defined. Subclause (a)(ii) implies a reassessment of the residual charge allocation after 10 years (and then, potentially, annually after that) but is not clear. The question of when the residual charge "is to be assessed" (reassessed) is not answered explicitly. Subclause (a) does not address how to allocate the residual charge to new customers, who will not have any historical demand. In relation to subclause (b), it should be discretionary, not mandatory, for Transpower to use an alternative method for allocating the residual charge. Our proposed alternative drafting for subclause (b) (which would be in a separate clause) is as follows: *40A The **TPM** may provide for the **residual charge** to be allocated using an alternative method if Transpower considers that the alternative method would better meet the Authority's statutory objective than the method in clause 40.*

41.	The **TPM** must provide that, in initially allocating the **residual charge** under clause 40, Transpower may adjust the allocation where necessary to accommodate circumstances in which a designated transmission customer has experienced a substantial change in demand due to factors beyond their control or influence. For the purposes of this clause, a substantial change in demand is to be assessed relative to the designated transmission customer's remaining demand.	We assume the "substantial change" referred to in this clause is a change that occurs between July 2019 and the time the TPM commences. That should be stated. In our view it would be better to apply the same change triggers during that period as apply to the residual charge after it is initially allocated. We propose alternative drafting to achieve that below (clause ZA). The term "demand" should be avoided because the Code definition of demand is a measure of power rather than electrical energy. "Electricity consumption", with "electricity" having its Code meaning (i.e. electrical energy), is better. It is unclear whether this clause is intended to refer to a change in net or gross consumption (we assume the latter). We do not think it is practicable for Transpower to determine whether a change in electricity consumption could have been controlled or influenced (certainly the latter) by the customer. The words "due to factors beyond their control or influence" should be deleted. We note that this clause may not apply if we chose an alternative allocation method under clause 40(b) that does not rely on historical demand. Our proposed alternative drafting for clauses 41 and (to the extent it applies to the residual charge) 42 is below (clauses ZA to ZC).

	Provisions relating to adjustments	
42.	The **TPM** must: (a) provide for a process for allocating **benefit-based charges** and **residual charges** in respect of: (i) new **large consumers or generators**;	Subclause (a) only captures events that increase generation or load directly or indirectly connected to the grid. Because there is no equivalent of proposed clause 26 (substantial and sustained change in grid use) for the residual charge, there is no ability for Transpower to reallocate the residual charge if a load customer disconnects from the grid. We would not be able

	(ii) existing **large consumers or generators** who establish a new plant or generating unit or increase (where that increase is substantial and sustained) an existing plant's electricity use or an existing generating unit's generation, where that plant or generating unit is directly or indirectly connected to the grid; (b) provide that, where a designated transmission customer sells part of its business, Transpower may allocate the designated transmission customer's charges between the original and new owners; and (c) avoid creating inefficient incentives for a **large consumer or generator** to shift their point of connection (beyond the ability to do so in the prudent discount policy). The prudent discount policy may apply to circumstances where a **large consumer or generator** is considering shifting their point of connection, but the **TPM** must include additional provisions to avoid creating such incentives.	to continue to charge the disconnected load customer if they were no longer a designated transmission customer. In that case there would be no mechanism under the TPM by which we could recover the former load customer's share of the residual charge. At clause 66 we have suggested a new defined term "large plant" in place of the defined term "large consumer or generator". In our view the change trigger in subclause (a)(i) needs to focus on the plant rather than the consumer or generator. We note the subclause (a)(i) change trigger does not capture all new transmission customers (smaller consumers, smaller generators and distributors). We do not think it is intended that some new transmission customers escape an allocation of benefit-based charges for past investments and the residual charge. Subclause (c) should be deleted. We cannot do anything about the incentives (inefficient or otherwise) that the design of the charges in the guidelines may create. For example, we cannot do anything about: - a transmission customer choosing to shift to a different grid connection point to get a better benefit-based charge outcome (which would be a substantial and sustained change in grid use); or - a large consumer deciding to disconnect from the grid and become self-sufficient to avoid transmission charges. The risk of inefficient investments driven by transmission charges should continue to be dealt with via the established prudent discount mechanism. If subclause (c) is retained it should be amended for accuracy as to how the prudent discount policy works. The application of the prudent discount policy would involve a notional switch, not an actual one as implied by the current drafting of subclause (c). The final sentence of subclause (c)

		suggests that prudent discounts are only available to large consumers or generators, which is not the case. Our proposed alternative drafting for clause 42 is above (clauses XA to XC for benefit-based charges) and below (clauses ZA to ZC for the residual charge).

Transpower comment:

Clauses ZA, ZB and ZC are proposed to replace clauses 41 and (to the extent it applies to the residual charge) 42. Refer to our comments on each of those clauses.

*ZA The **TPM** must provide that, when initially allocating the **residual charge** in accordance with the method referred to in clause 40, Transpower may adjust the allocation if any of the events referred to in clause ZC have occurred between 1 July 2019 and when the **residual charge** is initially allocated.*

*ZB. The **TPM** must provide that the allocation of the **residual charge** must not change except:*

(a) as specified in clause ZC; or

(b) if Transpower re-evaluates the allocation in accordance with the method referred to in clause 40 or 40A.

*ZC. Transpower may change the allocation of the **residual charge** if:*

*(a) new **large consumer plant** connects directly or indirectly to the grid;*

*(b) there has been a substantial and sustained increase in existing **large consumer plant's** electricity consumption;*

*(c) there is a new direct connection to the grid by a new or existing **load customer**, other than in the circumstances described in subclause (a);*

*(d) a **load customer** ceases to have a direct connection to the grid at one or more of its points of connection; or*

*(e) a **load customer** sells part of its business.*

	The charges may need to be scaled back	
43.	The **TPM** must provide for the charges set under it to be scaled back if, in any **pricing year**: (a) applying the other provisions of the TPM would result in Transpower recovering more than its **forecast MAR**; or (b) Transpower wishes to recover less than its **forecast MAR**.	
44.	The **TPM** must provide that, where clause 43(a) applies, charges are to be scaled back in the following order: (a) the **residual charge**; (b) the **annual benefit-based charge** for **pre-2019 benefit-based investments**; then (c) the **annual benefit-based charge** for **post-2019 benefit-based investments**.	The residual charge would not be able to be scaled back in the clause 43(a) scenario because it would already be zero (there being no excess revenue requirement to wash up). There is one benefit-based charge per investment so in subclauses (b) and (c) "annual benefit-based charge" should be plural.
45.	The **TPM** must provide that, where clause 43(b) applies, Transpower may first scale back the **annual benefit-based charge** for a **benefit-based investment**. However, such a scaling back of the **annual benefit-based charge** must not result in an increase to the **residual charge**.	The different treatment of the clause 43(a) and 43(b) scenarios seems arbitrary and is not explained in the issues paper. "A benefit-based investment" implies that only one benefit-based charge can be scaled back, which may not be the intent.

	Main component 4: prudent discount policy	
46.	The **TPM** must provide for a prudent discount policy that encourages designated transmission customers not to inefficiently bypass the grid, including encouraging **load customers** not to inefficiently disconnect from the grid in favour of alternative supply.	The use of the word "bypass" implies disconnection from the grid, whereas the notional project may involve the customer changing its point of connection to the grid to avoid benefit-based charges (for example). We suggest "inefficiently bypass, or change point of connection to, the grid".

47.	The prudent discount must be available where a designated transmission customer can establish that: (a) it would be technically and operationally feasible, and commercially beneficial, for the designated transmission customer to undertake the relevant action described in clause 46; and (b) the relevant action would be inefficient to implement given Transpower's economic costs of providing the designated transmission customer with access to the **interconnected grid** and the economic costs incurred by the designated transmission customer if it proceeded with the relevant action described in clause 46.	In subclause (b) "interconnected grid" should be "grid".
48.	The prudent discount must apply for the **remaining life** of the relevant investment, unless Transpower and the party receiving the prudent discount agree to a different period.	There should not be a default period of the remaining life of the investment (which investment?) because the conditions that applied when the prudent discount was agreed may not be enduring. As this clause is drafted, customers will be able to force inappropriately long prudent discounts. In our view the period should be whatever the parties agree it is.

	Cap on transmission charges	We do not agree with the design of the proposed cap. See our comments in the covering letter of our submission and answers to the Authority's questions 39 to 42.
49.	Subject to clause 53, the **TPM** must provide for a price cap on each **load customer's** total **transmission charges** excluding: (a) any **connection charge**;	In our view the proposed drafting for the Authority's price cap design would benefit from some changes for clarity. Our proposed alternative drafting for clauses 49 to 53 (assuming the Authority's price cap design is retained) is below (clauses YA to YH and related definitions).

	(b) any **peak charge**; (c) any kvar charge; (d) any charge attributable to investments commissioned or otherwise entering into operation after the end of the 2019/20 **pricing year**; (e) any **benefit-based charge** in respect of any **pre-2019 benefit-based investment** identified by means of a method established under clauses 62 and 63; (f) any increase in the **residual charge** due to a **reassignment** of a **benefit-based investment**; (g) any increase in a designated transmission customer's allocation of the **annual benefit-based charge** for a **benefit-based investment** due to a reallocation under clause 26; and (h) the application of clause 42.	If the Authority were to leave the design of the price cap to be developed by Transpower, a clause similar to the transitional clause in the current guidelines would suffice. For example: *Y. The **TPM** must provide for transitional arrangements where changes to the **TPM** as a result of these **Guidelines** would otherwise lead to large increases or decreases in **transmission charges** for designated transmission customers.*
50.	Subject to clause 53, in setting a price cap, the **TPM** must provide for: (i) any increase in a distributor's **transmission charges** subject to the price cap as set out in clause 49, as compared to its **transmission charges** minus its connection charges in the 2019/20 **pricing year**, to be limited to no more than the amount resulting from the following formula: B x (0.035 + CPI + L) where: B is Transpower's estimate of the total electricity bill for all consumers supplied, directly or indirectly, from the distributor's network in the 2019/20 **pricing year** (expressed in dollars), calculated as: $B = C + P*V$	

	and where CPI is the change in the Consumer Price Index since the 2019/20 **pricing year** (expressed as a decimal); L is the increase in the distributor's load since the 2019/20 **pricing year**, if any (expressed as a decimal); *C* is the distributor's total line charge revenue for the 2019/20 **pricing year** excluding GST from Schedule 8 Report on Billed Quantities and Line Charges Revenues of the Electricity Distribution Information Disclosure Determination 2012; *P* is the volume weighted average of wholesale energy prices at the distributor's grid exit point or points for the 5 years up to and including the 2019/20 **pricing year** from the Authority's Electricity Market Information database, expressed in $/MWh and excluding GST, with weights being the gross load as determined by the reconciliation manager; and *V* is the distributor's total gross load for the 2019/20 **pricing year**, expressed in MWh, as determined by the reconciliation manager; (j) any increase in a direct consumer's **transmission charges** subject to the price cap as set out in clause 49, as compared to its **transmission charges** minus its connection charges in the 2019/20 **pricing year**, to be limited to no more than: B x (0.035 + 0.02 x Y + CPI + L) where:	

		B is Transpower's estimate of the total electricity bill of that direct consumer in the 2019/20 **pricing year** (expressed in dollars), calculated as; B = T + P*V and where Y is the greater of zero and of the number of **pricing years** which have elapsed since the 2019/20 **pricing year** minus 5; CPI is the change in the Consumer Price Index since the 2019/20 **pricing year** (expressed as a decimal); L is the increase in the direct consumer's load since the 2019/20 **pricing year**, if any (expressed as a decimal); T is what the direct consumer's total **transmission charge** (including any **connection charge**) is or would have been under the existing **TPM** in the 2019/20 **pricing year**, excluding GST; P is the volume weighted average of wholesale energy prices at the direct consumer's grid exit point or points for the 5 years up to and including the 2019/20 **pricing year** from the Authority's Electricity Market Information database, expressed in $/MWh and excluding GST; and V is the total direct consumer's load in the 2019/20 **pricing year** in MWh, such information to be obtained from the reconciliation manager; and	
	(k)	the price cap to be permanently removed for a particular **load customer** if, in any **pricing year** after the **pricing year** in which **benefit-based charges** are first applied to **low-value post-2019 benefit-based investments**, the cap does not have the effect of	

	reducing the **load customer's transmission charges** subject to the price cap as set out in clause 49.	
51.	To the extent that the price cap results in a reduction in **transmission charges** for one or more **load customers**, the revenue so forgone is to be recovered by a surcharge on and proportional to the total of the **benefit-based charge** for the investments listed in clause 13(b) and the **residual charge** for each <u>designated transmission customer</u>.	
52.	The surcharge on the **benefit-based charge** and the **residual charge** for a <u>designated transmission customer</u> is to be reduced if necessary and to the extent necessary to ensure that its **transmission charges** subject to the price cap as set out in clause 49 meet the condition in clause 50.	
53.	The price cap provisions must not prevent <u>Transpower</u> from recovering its **forecast MAR**.	

Transpower comment:

Clauses YA to YH are proposed to replace clauses 49 to 53. See our comments on clause 49.

[New definitions]

initial pricing year *means the first* ***pricing year*** *after the last* ***pricing year*** *for which* ***transmission charges*** *are set under the* ***TPM*** *applicable on the date of these* ***Guidelines****.*

shortfall *means the part of <u>Transpower's</u>* ***maximum revenue*** *that, but for clause YH, would not be recovered after applying the caps in clauses YB and YD.*

specified charges *means, for a* ***load customer****:*

(a) for the 2019/20 ***pricing year****, the* ***load customer's*** *total* ***transmission charges*** *less its* ***connection charges****; and*

(b) for the ***initial pricing year*** *and each subsequent* ***pricing year****, the* ***load customer's****:*

(i) ***benefit-based charges*** *for* ***benefit-based investments*** *first* ***commissioned*** *before 1 April 2020, except for:*

(A) ***benefit-based charges*** *for* ***pre-2019 benefit-based investments*** *not listed in clause 13(b); and*

(B) *increases in* ***benefit-based charges*** *arising from reallocations under clause 26;*

(ii) ***residual charge****, except for any part of it attributable to* ***reassignment****; and*

(iii) *allocation of the* ***shortfall*** *under clause YH.*

specified charges increment *is as described in clause YC or YE.*

specified pricing year *means the first* ***pricing year*** *for which the* ***transmission charges*** *include a* ***benefit-based charge*** *for a* ***low-value post-2019 benefit-based investment****.*

YA. *The* ***TPM*** *must provide for a cap on* ***specified charges*** *for* ***load customers*** *that complies with clauses YB to YG.*

YB. *Subject to clauses YF and YG, a distributor's* ***specified charges*** *for each* ***pricing year*** *from and including the* ***initial pricing year*** *(****pricing year*** *n) must not be more than:*

$DSC_{19/20} + Dcap_n$

where:

$\boldsymbol{DSC_{19/20}}$ *is the distributor's* ***specified charges*** *for the 2019/20* ***pricing year****; and*

$\boldsymbol{Dcap_n}$ *is the distributor's* ***specified charges increment*** *for* ***pricing year*** *n.*

YC. *A distributor's* ***specified charges increment*** *for* ***pricing year*** *n is:*

$(C + (P \times V)) \times (0.035 + CPI_n + L_n)$

Where:

C *is the distributor's total line charge revenue (excluding GST) for the 2019/20* ***pricing year****, determined from the distributor's Schedule 8 Report on Billed Quantities and Line Charge Revenues for the disclosure year ending on 31 March 2020 disclosed under the Electricity Distribution Information Disclosure Determination 2012 [2012] NZCC 22;*

P *is the volume weighted average of the final prices in $/MWh (excluding GST) at the distributor's* ***grid exit point(s)*** *for the five* ***pricing years*** *up to and including the 2019/20* ***pricing year****, determined from the Authority's Electricity Market Information database and (as to weightings) electricity consumption information to be obtained from the reconciliation manager;*

V *is the total gross electricity consumption in MWh on the distributor's local networks for the 2019/20* ***pricing year****, determined from information to be obtained from the reconciliation manager;*

$\boldsymbol{CPI_n}$ *is the percentage increase (if any) in the Consumers Price Index (all groups) between the 2019/20* ***pricing year*** *and* ***pricing year*** *n, expressed as a decimal; and*

$\boldsymbol{L_n}$ *is the percentage increase (if any) in total gross electricity consumption on the distributor's local networks between the 2019/20* ***pricing year*** *and* ***pricing year*** *n, determined from information to be obtained from the reconciliation manager and expressed as a decimal.*

YD. Subject to clauses YF and YG, a direct consumer's ***specified charges*** *for each* ***pricing year*** *from and including the* ***initial pricing year*** *(****pricing year*** *n) must not be more than:*

$$CSC_{19/20} + Ccap_n$$

where:

$\boldsymbol{CSC_{19/20}}$ *is the direct consumer's* ***specified charges*** *for the 2019/20* ***pricing year****; and*

$\boldsymbol{Ccap_n}$ *is the direct consumer's* ***specified charges increment*** *for* ***pricing year*** *n.*

YE. A direct consumer's ***specified charges increment*** *for* ***pricing year*** *n is:*

$$(T + (P \times V)) \times (0.035 + CPI_n + L_n + (0.02 \times Y))$$

where:

T *is the direct consumer's total* ***transmission charges*** *(excluding GST) for the 2019/20* ***pricing year****;*

P *is the volume weighted average of the final prices in \$/MWh (excluding GST) at the direct consumer's* ***grid exit point(s)*** *for the five* ***pricing years*** *up to and including the 2019/20* ***pricing year****, determined from the Authority's Electricity Market Information database and (as to weightings) electricity consumption information to be obtained from the reconciliation manager;*

V *is the direct consumer's total electricity consumption in MWh for the 2019/20* ***pricing year****, determined from information to be obtained from the reconciliation manager;*

$\boldsymbol{CPI_n}$ *is the percentage increase (if any) in the Consumers Price Index (all groups) between the 2019/20* ***pricing year*** *and* ***pricing year*** *n, expressed as a decimal;*

$\boldsymbol{L_n}$ *is the percentage increase (if any) in the direct consumer's total gross electricity consumption between the 2019/20* ***pricing year*** *and* ***pricing year*** *n, determined from information to be obtained from the reconciliation manager and expressed as a decimal; and*

Y *is the greater of:*

(a) zero; and

(b) the number of ***pricing years*** *between the 2019/20* ***pricing year*** *and* ***pricing year*** *n minus five.*

YF. The cap in clause YB or YD, as applicable, does not apply to a ***load customer*** *from the* ***pricing year*** *immediately after the first* ***pricing year*** *after the* ***specified pricing year*** *that the cap does not reduce the* ***load customer's specified charges****.*

YG. The caps in clauses YB and YD must not result in <u>Transpower</u> recovering less than its ***maximum revenue****.*

YH. The ***TPM*** *must provide that any* ***shortfall*** *is to be allocated to <u>designated transmission customers</u> in proportion to their:*

(a) ***benefit-based charges*** *for the* ***benefit-based investments*** *listed in clause 13(b); plus*

(b) ***residual charge****.*

Transpower comment:

The new guidelines and TPM are an opportunity to address the so-called "first mover disadvantage" for investments that are funded by one or a few parties through investment agreements. The disadvantage arises because, currently, subsequent customers who benefit from those investments do not pay a capital contribution to them through transmissions charges.

Accordingly, clause V and related definitions are proposed. The "funded asset charge" would be a new core component and so consequential changes to the guidelines would be required.

[New definitions]

funded asset *means a <u>grid asset</u>, the construction costs for which were partially or fully funded by one or more parties under an <u>investment agreement</u>.*

funded asset charge *means the charge described in clause V.*

V. The ***TPM*** *must provide for <u>designated transmission customers</u> who connect to, or otherwise derive a* ***positive net private benefit*** *from, a* ***funded asset*** *to pay a contribution to the costs incurred by the funding party or parties for the construction of the* ***funded asset*** *(a* ***funded asset charge****). The* ***funded asset charge*** *must be deducted from:*

(a)	*the **transmission charges** of the funding party or parties if they are designated transmission customers; or*
(b)	*otherwise, the **residual charge**.*

	Additional components	
54.	The **TPM** must incorporate each of the following **additional components**, where including that component would, in Transpower's reasonable opinion, better meet the Authority's statutory objective than not including that **additional component**: (a) staged commissioning, as described in clause 55; (b) charges for assets principally providing connection services, as described in clause 56; (c) charges for connection assets, as described in clause 57; (d) a transitional peak charge, as described in clauses 58 to 61; (e) including additional pre-2019 investments in the benefit-based charge, as described in clauses 62 and 63; (f) charging for **opex**, as described in clause 64; and (g) a kvar charge, as described in clause 65.	The inclusion (or not) of the additional components should be at our discretion, even if the statutory objective test is arguably satisfied ("must" should be "may"). Making their inclusion mandatory would invite challenge from stakeholders who would prefer that any omitted additional components were included. We note that the Code does not require the TPM to be the *best* possible manifestation of the statutory objective; the TPM is required to be *consistent* with it.
	Additional component A: staged commissioning	
55.	This component must provide a method for Transpower, at its discretion, to adjust the time profile and allocation of charges over a **benefit-based investment's remaining life** where an investment is **commissioned** in stages so that it sometimes meets the definition of a **connection asset**, in order to best reflect the benefits provided while it is a connection investment relative to the benefits provided after it has become an investment in the **interconnected grid**. The **benefit-**	In our view this additional component should be deleted. There is a logic problem with this additional component. Following *Vector* v *Transpower*, the status quo is the same as what the additional component is advocating (i.e. the TPM speaks in the present tense when it comes to grid asset classification). As a result, it is unclear whether the proposed TPM could take the opposite approach (i.e. only the final intended commissioned state is relevant), or a different approach, if we consider that would produce

	based charge must recover the present value of the **covered cost** of each **benefit-based investment**, less any **connection charges** already paid.	better outcomes. Clauses 10 and 11 provide us with sufficient flexibility to decide what the rule should be. We note that, under the status quo, it is highly unlikely our customers would agree to staged commissioning regardless of whether staged commissioning is efficient or otherwise the best outcome for consumers. The status quo is not clearly consistent with the Authority's statutory objective. In any event, the drafting of this additional component contains a contradiction. An asset that is a benefit-based investment by definition cannot "sometimes meet the definition of a connection asset" because the definitions are mutually exclusive.
	Additional component B: charges for assets principally providing connection services	
56.	This component must provide a method to ensure that charges that apply to <u>assets</u> that provide connection services are not affected by connecting those <u>assets</u> to other <u>assets</u>, if they continue to provide principally the services of a **connection asset**, notwithstanding that they do not meet the formal definition of a **connection asset**.	This additional component is intended to close an undesirable loophole in the current TPM. As such, we think it should be part of the core requirements for the connection charge rather than an additional component. There is a reasonably straightforward way to address this issue at a definitional level in the TPM rather than by charging for interconnection assets as if they were connection assets. Our proposed alternative drafting is as follows (incorporated as a core component): *Q. The **TPM** must include a method to ensure that **connection assets** cannot be changed into <u>interconnection assets</u> by a person other than <u>Transpower</u> investing in other <u>assets</u> to create an interconnection loop. The method may be applied to reclassify <u>interconnection assets</u> that would have remained as **connection assets** if the method had applied at the time those <u>assets</u> became <u>interconnection assets</u>.*

		This additional component must be able to be applied retrospectively. Otherwise the reclassification caused by the HAI-TMU line, which was the impetus for this additional component, will not be able to be addressed.
	Additional component C: charges for connection assets	
57.	This component must provide for the method for determining the annual amount to be recovered for each new **connection asset** to align with the method for determining the **annual benefit-based charge** for **post-2019 benefit-based investments**, notwithstanding the requirements of clauses 10 and 11.	In our view this additional component should be deleted. The connection charge is already a beneficiaries pay charge and is not controversial. Any efficiencies that might be gained from treating connection assets as benefit-based assets are very unlikely to justify the transaction cost of the change.
	Additional component D: transitional peak charge	We are strongly of the view that a peak pricing signal should be retained in the TPM. See our comments in the covering letter of our submission and answers to the Authority's questions 44 to 46. In our view the drafting of this additional component is overly prescriptive. Among other things, there is no need for the guidelines to specifically mandate a phase out mechanism for the charge, especially as it is acknowledged that the phase out period may be extended and the phase out may be paused or reversed. See our proposed alternative drafting below (clauses UA and UB), which assumes the Authority choses to retain a default five-year phase out period (which we disagree with). The peak charge should not be described as "transitional". There may be good reasons for the peak charge to continue indefinitely, as contemplated by clause 61. In our view opportunities to incentivise peak management through the design of transmission charges should not be passed up in favour of more costly alternatives (such as paying for demand response as a transmission alternative).
58.	This component must provide a method for determining, in respect of the transitional **peak charge**:	The words "would experience congestion" imply the grid congestion would be experienced immediately without the peak charge. Any peak charge is more likely to be aimed at avoiding congestion in the longer term, and

	(a) the initial level of the charge; (b) the designated transmission customers or geographic areas to, or the circumstances in, which it applies; and (c) how the charge is to be allocated between designated transmission customers. The transitional **peak charge** may only apply in respect of those geographic areas, circuits or other circumstances which, in Transpower's reasonable opinion, would experience congestion without a transitional **peak charge**.	potentially beyond the five-year phase out period proposed by the Authority. Further, the practical capability to reduce peaks cannot be established overnight in response to a new charge that only applies once the grid is congested.
59.	If Transpower determines to include a transitional **peak charge** in the **TPM**, it must include in its outline required under clause 4 of these **Guidelines**, an explanation as to why it considers that grid demand will not be adequately controlled by the other prices including nodal pricing.	This clause is unnecessary given clause 4.
60.	If the **TPM** includes a transitional **peak charge**: (a) the transitional **peak charge** must be progressively phased out, such phase-out to commence no later than one year after the transitional **peak charge** is first imposed; (b) the phase-out of the transitional **peak charge** must result in it being phased out completely within five years of the **TPM** entering into effect. Transpower may, during this phase-out period, temporarily pause the phase-out or increase the transitional **peak charge**, including by reinstating a transitional **peak charge** which has already been phased out, where doing so would, in Transpower's reasonable opinion, better meet the Authority's statutory objective, provided that the phase-out is still completed within the five-year period unless Transpower has obtained the Authority's approval under paragraph (d) below to extend that period;	This clause is drafted in a way that makes the five-year time limit a hard stop for the peak charge. That is, any reinstatement must happen within the five years (or such longer phase out period as the Authority approves). In our view this should be changed so that a peak charge can be reinstated at any time if it is considered reasonably necessary to manage peak demand, without Transpower having to carry out an operational review under clause 12.85 of the Code.

	(c) the **TPM** must include the process for phasing out the transitional **peak charge**, including specifying the maximum transitional **peak charge** which can be levied in any year, which may be expressed as a percentage of the initial transitional **peak charge**; and (d) the TPM must include provision for Transpower to apply to the Authority during the phase-out period, to deviate from the maximum transitional **peak charge** that may be levied in any year, the time limit on or duration of the phase-out period. Transpower must provide to the Authority such information as the Authority requires to determine an application under this paragraph.	
61.	Notwithstanding anything in clause 60 above, after the phase-out period has ended, Transpower may propose to reinstate or introduce a new transitional **peak charge** as part of a review under clause 12.85 of the **Code**. In proposing a reinstated or new transitional **peak charge**, Transpower must provide to the Authority such information as the Authority requires to assess Transpower's proposal.	This clause is unnecessary. Transpower is already empowered under the Code to carry out operational reviews on any aspect of the TPM.

Transpower comment:

Clauses UA to UB are proposed to replace clauses 58 to 61. Refer to our comments on those clauses.

*UA. This component must provide for a **peak charge** that applies to the extent Transpower considers that other prices, including nodal prices, do not adequately control peak demand for **transmission lines services** in particular geographic areas or circumstances.*

*UB. If the **TPM** includes a **peak charge**, the **peak charge** must not apply after the fourth **pricing year** after the **initial pricing year** unless Transpower obtains the Authority's approval.*

	Additional Component E: Including additional pre-2019 investments in the benefit-based charge	
62.	This component must include a method for extending the definition of **benefit-based investment** to other **pre-2019 benefit-based investments** in the **interconnected grid** and related services, including transmission alternatives, that contribute to Transpower's **forecast MAR**.	
63.	If the **TPM** includes such a method, it: (a) must specify a method for allocating the **annual benefit-based charges** for the **benefit-based investments** between designated transmission customers. The method must be a simple method as described in clause 23; (b) must provide for the **benefit-based charge** for such **benefit-based investments** to be capped at the present value of the aggregate **positive net private benefits** expected to be derived by designated transmission customers from the **benefit-based investment** over its **remaining life**; and (c) may include transitional provisions which phase in the relevant charges.	There may not be a simple method (as referenced in subclause (a)) because clause 20 is permissive, not mandatory. Subclause (a) is unnecessary in any event because clause 21(d) already covers pre-2019 investments introduced using this method.
	Additional component F: charging for opex	
64.	This component must include a method for allocating **opex** expended in relation to **connection assets** and assets in a **benefit-based investment** to the designated transmission customers paying charges in relation to that asset or investment. The method must not use a proxy or generalised rule for allocation.	
	Additional component G: kvar charge	
65.	This component must include a method for imposing a kvar charge on reactive power.	

	Interpretation	
66.	In these **Guidelines**, unless the context otherwise requires it: **2019 Issues Paper** means the issues paper prepared by the Authority under clause 12.81 of the **Code** and published by the Authority on [**date**] 2019.	
	additional component means one of the components required by clause 54 of these **Guidelines** to be included in the **proposed TPM** where Transpower considers that including that component will better meet the Authority's statutory objective than not including it.	The inclusion of an additional component should be discretionary, not "required by" clause 54.
	annual benefit-based charge means the amount of the **benefit-based charge** to be recovered in respect of a particular **benefit-based investment** in any one **pricing year**.	
	asset refurbishment has the meaning given to it in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, as amended from time to time.	The capex input methodology determination is referred to multiple times. We suggest it be defined as "Transpower Capex IM".
	asset replacement has the meaning given to it in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, as amended from time to time. **benefit-based charge** means the charge as described in clause 12.	
	benefit-based investment has the meaning given to it in clause 13.	We propose this alternative drafting: ***benefit-based investment** means, as the context requires:* *(a) an investment or project specified in clause 13; or* *(b) the asset or assets that resulted or result from the investment or project.*

	Code means the Electricity Industry Participation Code 2010, as amended from time to time.	
	commissioned has the meaning given to it in the Commerce Commission's *Transpower Input Methodologies Determination 2010* [2012] NZCC 17, as amended from time to time.	The input methodologies determination is referred to multiple times. We suggest it be defined as "Transpower IMs".
	connection assets means the assets owned by Transpower used to connect a designated transmission customer to the grid**,** and may have a more precise definition in the **transmission pricing methodology** as amended from time to time.	This definition does not clearly exclude interconnection assets. We propose this alternative drafting: ***connection asset*** *has the meaning given to it in the* ***TPM*** *at the date of these* ***Guidelines****, subject to any changes to that definition permitted by these* ***Guidelines****.*
	connection charge means the charge described in clauses 10 and 11. **covered cost**, in relation to a **benefit-based investment**, has the meaning given to it in clause 14. **electricity market benefit or cost element** has the meaning given to it in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination 2012* [2012] NZCC 2, as amended from time to time.	
	forecast MAR means, for a **pricing year**, Transpower's forecast maximum allowable revenue as set by the Commerce Commission in the **IPP**, as amended from time to time. The **IPP** for the **pricing year** commencing 1 April 2010 is the Transpower Individual Price-Quality Path Determination 2020.	We propose this alternative drafting: ***maximum revenue*** *means, for a* ***pricing year,*** *the maximum revenue Transpower may recover during that* ***pricing year****, as set by the* ***IPP.***
	generation customer means a designated transmission customer that is a generator. **Guidelines** means these guidelines. **high-value**, in respect of a **benefit-based investment**, means a **benefit-based investment** that, at the time it was first **commissioned** exceeded the "base capex threshold" as defined in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, as amended from time to time,	

	whether or not the investment would otherwise meet the test for "major capex". **interconnected grid** means the grid including the HVDC link but excluding **connection assets.**	
	IPP means Transpower's individual price-quality path determined by the Commerce Commission under Part 4 of the Commerce Act 1986 from time to time. At the date of these **Guidelines** the relevant determination is the *Transpower Individual Price-Quality Path Determination 2015.*	2015 should be either 2019 or 2020, with an appropriate citation in due course.
	large consumer or generator means an actual or potential user of **transmission lines services** (whether as load or generation) which could reasonably contemplate shifting its point of connection.	This definition captures distributors, which we think is unintentional given the use of the word "consumer". In our view the focus should be on the consumer's or generator's plant, not the consumer or generator itself. We propose these alternative definitions: ***large consumer plant*** *means new or existing electricity consuming plant:* *(a) that is directly connected to the grid; or* *(b) that:* *(i) is indirectly connected to the grid; and* *(ii) Transpower considers is of such a size that it could viably connect directly to the grid.* ***large generator plant*** *means new or existing generating plant:* *(a) that is directly connected to the grid; or* *(b) that:* *(i) is indirectly connected to the grid; and* *(ii) Transpower considers is of such a size that it could viably connect directly to the grid.*

		***large plant** means **large consumer plant** or **large generator plant**.*
	load customer means a designated transmission customer that is a distributor or direct consumer.	In this definition "distributor" needs to be "distributor directly connected to the grid" because the Code definition of "distributor" captures embedded network owners.
	low-value means, in respect of a **benefit-based investment**, a **benefit-based investment** which does not meet the definition for a **high-value benefit-based investment.** **net private benefit** means, for a designated transmission customer: (a) the value of the private benefits which are consistent with **electricity market benefit or cost elements** that arise from the **benefit-based investment** in respect of that designated transmission customer from the commencement date of the **TPM**; less (b) the value of the private costs which are consistent with **electricity market benefit or cost elements** (but excluding the cost of the **benefit-based investment** itself) that arise from that **benefit-based investment** in respect of that designated transmission customer from the commencement date of the **TPM**, provided that Transpower may, at its discretion, include as part of the calculation the value of other benefits or costs where those benefits or costs are substantial and result from the **benefit-based investment.** **opex** means "operating cost" as defined in the Commerce Commission's *Transpower Input Methodologies Determination 2010*, as amended from time to time.	

	peak charge means a charge, over and above nodal prices and the other **transmission charges** provided for in these **Guidelines**, imposed to influence peak demand for use of the grid.	
	positive net private benefit means for a designated transmission customer: (a) the **net private benefit** if it is positive; or (b) zero if it is not	
	post-2019 means, in respect of a **benefit-based investment**, a **benefit-based investment** to the extent that it is first **commissioned** after the publication of the **2019 Issues Paper** (including any part of a **pre-2019 benefit-based investment** to the extent that it is **commissioned** after this date) and which at the relevant time of **commissioning** constitutes base capex or major capex as defined in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2.	For clarity, this definition should just state the relevant date (23 July 2019) rather than "after the publication of the 2019 Issues Paper". Same for the definition of "pre-2019".
	pre-2019 means, in respect of a **benefit-based investment**, a **benefit-based investment** to the extent that it is **commissioned** on or before the date of publication of the **2019 Issues Paper** and which at the relevant time of **commissioning** would have constituted base capex or major capex as defined in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2.	See our comment on the definition of "post-2019".
	pre-2019 means, in respect of a **benefit-based investment**, a **benefit-based investment** to the extent that it is **commissioned** on or before the date of publication of the **2019 Issues Paper** and which at the relevant time of **commissioning** would have constituted base capex or major capex as defined in	

	the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2. **pricing year** has the meaning given to it in the **IPP.** **reassignment** means a reassignment of charges from the **benefit-based charge** to the **residual charge** due to a reduction in the value of an asset for the purposes of the **benefit-based charge**, and **reassignments** and **reassigned** have equivalent meanings. **regulatory asset base** means, for a **pricing year**, the asset base used to determine **forecast MAR** for the **pricing year.** **remaining life** means, for a **benefit-based investment**, the **benefit-based investment's** expected economic life at the time the relevant clause of the **TPM** applies. **residual charge** means the charge as described in clause 39. **TPM** means the transmission pricing methodology.	
	transmission lines services has the meaning given to it in the **IPP.**	"Electricity transmission services", not "transmission lines services", is the defined term in the IPP. "Electricity lines services" (from which "electricity transmission services" in the IPP takes its meaning) is defined in the Commerce Act, but includes system operator services. Accordingly, this definition should be: ***transmission lines services*** *means electricity transmission services (as defined in the* ***IPP****) excluding services performed by Transpower as system operator.*
	transmission charges means the charges provided for by the **TPM**, as amended from time to time. **upgrading expenditure** has the meaning given to it in clause 30.	

	value of commissioned assets has the meaning given to it in the Commerce Commission's *Transpower Input Methodologies Determination 2010* [2012] NZCC 17, as amended from time to time. **WACC** means, for a **pricing year**, the pre-tax nominal weighted average cost of capital used to determine **forecast MAR** for the **pricing year.**	
67.	In these **Guidelines**, unless the context requires otherwise, any other term that is defined in Part 1 of the **Code**, and used but not defined in these **Guidelines**, has the same meaning as in Part 1 of the **Code**. Terms defined in Part 1 of the **Code** are underlined in these **Guidelines**.	Not all Code-defined terms are used in their Code sense in the guidelines. We propose this alternative drafting: *67. In these **Guidelines**, unless the context requires otherwise:* *(a) a reference to an indirect connection to the <u>grid</u> means a connection to the <u>grid</u> through one or more other <u>networks</u>; and* *(b) underlined terms have the same meaning as in Part 1 of the **Code**.*

Schedule 1 Annual benefit-based charges for the benefit-based investments

	Bunnythorpe-Haywards	HVDC	LSI Reliability	LSI Renewables	North Island grid upgrade	Wairakei Ring	UNI dynamic reactive
Alpine Energy	3.11%	0.85%	1.49%	2.98%	0.30%	0.24%	0.30%
Aurora Energy	5.71%	1.57%	0.90%	4.48%	0.30%	0.27%	0.30%
Beach Energy Resources (Kupe)	0.03%	0.07%	0.10%	0.08%	0.03%	0.04%	0.03%
Buller Electricity	0.27%	0.08%	0.12%	0.20%	0.03%	0.02%	0.03%
Centralines	0.07%	0.21%	0.24%	0.17%	0.05%	0.01%	0.05%
Contact Energy	2.11%	12.55%	23.98%	0.09%	5.96%	21.25%	5.96%
Counties Power	0.32%	1.06%	1.08%	0.85%	2.62%	1.41%	2.62%
Daiken Southland	0.28%	0.09%	1.38%	0.28%	0.02%	0.02%	0.02%
Eastland Network	0.17%	0.35%	0.56%	0.41%	0.05%	0.00%	0.05%
Electra	2.70%	0.79%	0.95%	0.67%	0.16%	0.14%	0.16%
Electricity Ashburton	1.70%	0.51%	0.76%	1.71%	0.26%	0.15%	0.26%
Electricity Invercargill	2.26%	0.59%	0.27%	2.19%	0.14%	0.12%	0.14%
Electricity Southland	0.12%	0.04%	0.05%	0.07%	0.01%	0.01%	0.01%
Genesis Power	1.22%	3.23%	0.00%	0.03%	3.66%	7.64%	3.66%
Horizon Energy	0.31%	0.36%	0.59%	0.66%	0.05%	0.00%	0.05%

MainPower	3.21%	0.88%	1.28%	2.95%	0.24%	0.20%	0.24%
Marlborough Lines	2.03%	0.45%	0.87%	1.87%	0.15%	0.12%	0.15%
Mercury	0.62%	0.00%	0.00%	0.00%	6.14%	10.53%	6.14%
Meridian	0.23%	33.70%	1.10%	0.05%	7.35%	0.00%	7.35%
Methanex	0.03%	0.06%	0.09%	0.07%	0.03%	0.04%	0.03%
Nelson Electricity	0.28%	0.06%	0.12%	0.23%	0.02%	0.02%	0.02%
Network Tasman	3.06%	0.71%	1.42%	2.57%	0.22%	0.18%	0.22%
Network Waitaki	1.13%	0.36%	0.52%	2.16%	0.13%	0.08%	0.13%
New Zealand Rail	0.04%	0.07%	0.10%	0.08%	0.20%	0.12%	0.20%
Nga Awa Purua JV	0.00%	0.00%	0.00%	0.00%	0.97%	8.00%	0.97%
Ngatamariki Geothermal	0.01%	0.00%	0.00%	0.00%	0.59%	4.86%	0.59%
Norske Skog	0.00%	0.00%	0.00%	0.00%	0.18%	2.47%	0.18%
Northpower	0.67%	1.13%	2.16%	1.78%	5.98%	2.90%	5.98%
Nova	0.10%	0.00%	0.00%	0.00%	0.21%	0.00%	0.21%
NZ Steel	0.30%	0.50%	0.96%	0.85%	2.47%	1.33%	2.47%
NZ Aluminium Smelters	22.04%	7.25%	2.12%	23.59%	1.61%	1.61%	1.61%
Orion	18.22%	4.88%	7.16%	14.69%	1.15%	1.00%	1.15%
OtagoNet JV	1.46%	0.41%	2.01%	2.03%	0.11%	0.11%	0.11%
Pan Pacific Forest Products	0.35%	0.47%	0.76%	0.69%	0.10%	0.00%	0.10%

Port Taranaki	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Powerco	4.02%	6.25%	8.55%	6.70%	1.91%	3.58%	1.91%
Resolution Developments	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%
Scanpower	0.05%	0.15%	0.17%	0.12%	0.03%	0.03%	0.03%
Southdown Generation	0.00%	0.00%	0.00%	0.01%	0.01%	0.00%	0.01%
Southern Generation	0.09%	0.01%	0.02%	0.16%	0.07%	0.64%	0.07%
Southpark Utilities	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
The Lines Company	0.16%	0.36%	0.47%	0.37%	0.18%	0.49%	0.18%
The Power Company	1.54%	0.34%	8.22%	2.04%	0.13%	0.12%	0.13%
Tilt Renewables	0.26%	0.01%	0.00%	0.00%	0.16%	0.00%	0.16%
Todd Generation Taranaki	0.24%	0.09%	0.00%	0.01%	0.26%	0.00%	0.26%
Top Energy	0.00%	0.24%	0.00%	0.00%	1.09%	0.51%	1.09%
TrustPower	0.01%	0.75%	0.00%	0.01%	0.16%	1.14%	0.16%
Tuaropaki Power	0.08%	0.06%	0.08%	0.07%	0.68%	0.13%	0.68%
Unison Networks	0.63%	1.34%	2.19%	1.60%	0.16%	0.00%	0.16%
Vector	5.51%	10.76%	18.95%	14.37%	51.26%	24.41%	51.26%
Waipa Networks	0.25%	0.59%	0.81%	0.64%	0.33%	1.01%	0.33%
WEL Networks	0.52%	1.13%	1.81%	1.41%	1.13%	2.36%	1.13%
Wellington Electricity	11.83%	4.24%	4.90%	3.21%	0.83%	0.65%	0.83%

Westpower	0.40%	0.09%	0.21%	0.46%	0.05%	0.03%	0.05%
Whareroa Cogeneration	0.10%	0.03%	0.00%	0.00%	0.02%	0.00%	0.02%
Winstone Pulp International	0.17%	0.29%	0.43%	0.36%	0.07%	0.00%	0.07%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

TRANSPOWER

Keeping the energy flowing

Attachment C: 2019 Issues Paper questions and answers

Chapter 2

Q1. Have the problems with the current TPM been correctly identified? In what ways does the current TPM work well?

The Authority has identified some problems with the current TPM with which we agree. However, in our view, the problems could be dealt with more quickly, more effectively and efficiently than extensive reforms, with less risk and at a lower cost by incrementally reforming the existing TPM and Guidelines. Some suggestions for such reform are listed in **Appendix 1** of our submission.

While the current TPM is not perfect, it is not broken either. We reiterate our submission on the Authority's Second Issues Paper that:

> *with some limited exceptions the current TPM is generally acknowledged by stakeholders and our customers as working well. This is reflected in submissions to the 2014/15 Operational Review, and the Authority's consultations. The options which have found most favour are retention of the status quo, or targeted changes to address specific concerns with the TPM. …*
>
> *This reflects the fact that:*
>
> 1. *The existing deep connection charge is a cost reflective charge that directly assigns costs for a significant proportion of the grid …*
> 2. *While the peak price signal provided by the RCPD interconnection charge may be considered blunt, it has helped to defer transmission investment (as detailed, for example, in the Authority's first Issues Paper).*
> 3. *The HVDC charge provides a clear North-South locational signal.*

The Authority's various TPM consultations have canvassed different problem definitions which, in our view, have tended to overstate the problems with the current TPM. As we said in our submission on the Second Issues Paper:

> *We caution the Authority against overstating problems with the status quo. We recognise that this is a natural tendency when making the case for change but, if unchecked, could lead to radical, disruptive change where targeted reform would be more proportionate, carry lower cost and risk and better promote the statutory objective.*

Chapter 3

Q2. What are your overall views on the Authority's proposal for changes to the TPM guidelines?

Transpower does not support the Authority's proposal.

We acknowledge that there is scope to improve the current TPM and we are open to having discussions with the Authority and other stakeholders about the most expedient way to resolve these.

We note that the positions in the Authority's current proposal are consistent at a high level with the Authority's earlier transmission pricing review proposals. While our stance on these points is largely unchanged, we consider that it is important to restate our view that the Authority's current TPM proposal runs a risk of not being in consumers' best interests and may not meet the Authority's statutory objective of delivering significant long-term benefits to consumers. Moreover, we are concerned that the proposal may not support New Zealand's transition to a low-emissions economy.

In our view it is important for the TPM and Guidelines to:

- support timely, efficient transmission investment via the Commerce Commission's processes;
- limit the risk of unintended consequences (including of inadvertently undermining New Zealand's efforts to respond to climate change);
- be workable, practicable and understandable to our customers and stakeholders; and
- limit the risk of legal challenges to transmission pricing decisions by being objective and fair.

When considered in context and against the counterfactual, it is not clear to us that the Authority's TPM proposal is consistent with these requirements. We elaborate on these points in our submission.

We are supportive of a measured approach to amending the TPM and Transpower is appreciative of the extensive work the Authority has conducted in identifying a number of significant issues that require review. In our view, extensive reform of the sort proposed by the Authority may not be the most effective or efficient manner to address TPM concerns. We consider that the concerns with the TPM may be more effectively and efficiently addressed through measured and incremental reform of the existing methodology. This would have the benefit of bringing the reforms to the market more quickly with a substantially lower risk of unintended consequences. Our submission proffers some practical options for such reform.

In the event that the Authority's proposal was to be implemented, then we consider that there are some workability issues in the drafting of the proposed new Guidelines that would benefit from further review.

Chapter 4

Q3.	**Does the CBA provide a reasonable estimate of the costs and benefits of the proposal? If not, what changes to the methodology and / or assumptions would improve the estimate?**

No. See our answer to Q4.

Q4.	**Do you have any comments on the matters covered in chapter 4?**

The Authority considers its CBA supports a conclusion that its proposed approach to transmission pricing would promote the efficient operation of the electricity industry for the long-term benefit of consumers. To inform our submission on this premise we commissioned an expert review of the CBA from Axiom Economics (**Axiom**). Axiom's report is **Attachment A** to our submission.

Axiom concluded that the CBA cannot safely be taken at face value. Axiom considers that correcting two of the more serious errors in the Authority's CBA would turn the estimated net benefit into a substantial net cost. If the CBA was to be taken at face value, the modelling concludes that the proposal may not deliver a material net benefit for 12 years. However, the modelling also expects there to be a significant "political uncertainty event" within 11 years, which could take the form of another substantial change to the TPM. In other words, the Authority's CBA suggests the proposed TPM reform might deliver no net benefit for eleven years before it is itself supplanted by another reform.

We consider such a material change in approach to transmission pricing should be supported by a CBA that achieves a high level of acceptance from the experts who review it. We are therefore interested to hear the opinion of experts commissioned by other submitters, and from the Authority as to its confidence in how its proposal would benefit consumers over these timeframes.

Axiom's view is that the CBA is compromised, including for the following reasons:

- Neither the grid use model (which generates 96% of the estimated net benefits) nor the top-down modelling reflect the Authority's proposal.
- The net benefit estimate mistakenly includes $2.3b in bare wealth transfers that are neither benefits to New Zealand's economy nor improvements to the overall efficiency of the electricity industry. The analysis also ignores a $1.9b cost of additional investment that is estimated to be needed to produce the modelled benefits. Addressing these errors alone reduces the Authority's net benefit estimate to negative $1.5b.
- The modelling rests on assumptions that do not reflect the ways in which the electricity market works, or market participants act.
- Aspects of the modelling hinge crucially on assumptions and inputs that are arbitrary or lack objective foundation.

Axiom concludes that the CBA has no probative value and lends no support to the Authority's proposal.

Chapter 6

Q5. How long should Transpower have to complete its development of the TPM and why?

Should the Authority proceed with its proposed new approach to transmission pricing, proper engagement with our stakeholders during TPM development would be critical to producing the most durable TPM possible within the constraints of the Guidelines.

Constructive and highly engaged stakeholder participation would be key to achieving a successful development and implementation of any new TPM.

In our view 18 months to submit a new TPM consistent with the Authority's 2019 proposal, would be an ambitious and very challenging timeframe. Any less time introduces a very high level of risk to our ability to deliver a durable TPM proposal to the Authority. We would be more comfortable with 24 months.

There remains uncertainty about how we would recover our costs of TPM development, implementation and ongoing operation, should the Authority decide to issue new Guidelines. Certainty about this early in the process would support our ability to develop the new TPM in a suitable timeframe.

Q6. What checkpoints (if any) should the Authority set in the TPM development process?

Transpower disagrees with some aspects of the proposed checkpoints:

- Two or three months after the Guidelines are published would certainly be too soon for the first checkpoint. That would not be enough time for us to make "key design choices on allocation methods for the benefit-based charge and peak charge". We note that in our submission on the Second Issues Paper Supplementary Consultation we did not anticipate confirming the design of the benefit-based (then area-of-benefit) charge until around 12 months after publication of the new Guidelines, following at least two rounds of stakeholder consultation.

  In our view a first checkpoint after six months to present preferred design options for the benefit-based and peak charges would probably be achievable.

- We do not think we should be required to provide a preliminary draft of the TPM at the second checkpoint. At the second checkpoint, which should be no earlier than 12 months after publication of the new Guidelines, we anticipate being in a position to confirm final design choices for the benefit-based and peak charges. We may illustrate those choices with some preliminary drafting of the TPM, but the important information would be the choices themselves.

Q7. How should Transpower best engage with its stakeholders during its development of the TPM and how regularly should that engagement occur?

Transpower would certainly be engaging with all stakeholders during the TPM development phase. We provided an indicative plan for that engagement in our submission on the Second Issues Paper Supplementary Consultation.

We do not consider the Authority should set requirements for how and when Transpower engages with its customers and other stakeholders (other than the Authority checkpoints). How we do this should be kept flexible, working within the constraints of the Authority checkpoints and the overall timeframe for submitting the proposed TPM. This would allow our approach to adapt to specific TPM design issues that arise during the development phase and the resources and time we have available to engage with stakeholders on them. We agree with the Authority that the process would involve "balancing an appropriate level of engagement with timely completion". We consider it is unwise to attempt to predict what that level will be in advance.

We do not agree with the Authority's view that multiple full consultation rounds would be unnecessary. Although the proposed Guidelines are prescriptive in some areas, there are still a significant number of design choices we would be required to make in producing the TPM. Consultation on the Guidelines does not equate to consultation on those design choices. In our view, strong engagement with our stakeholders would save time and work in the end.

Q8. In addition to the specific questions above, do you have any further comments on the matters covered in chapter 6?

We do not agree that six weeks for consultation by the Authority on the proposed TPM would be enough time. This would likely be the first time stakeholders see the complete TPM, and there may have been significant design choices made since stakeholders were last consulted (especially if the Authority had referred the proposed TPM back to Transpower or made changes to the proposed TPM itself). The balance of six weeks for consultation and six-and-a-half months for the Authority's processes does not seem right.

While we agree the new TPM would need to be treated as a Code change, we do not think it would be appropriate for the Authority to make changes to the proposed TPM after consultation without coming back to Transpower to check on the workability of those changes. The Code makes Transpower responsible for drafting the TPM because it is Transpower that has to administer it.

We do not agree with the Authority that the upgrade to our transmission pricing software in 2019/20 would mean we could cut the TPM implementation time down to 13 months (from up to 28 months). The time it takes to implement any approved new TPM would depend on what the new TPM says, which is not known yet.

As we say in our answer to Q5, finding an appropriate way for Transpower to recover its costs of TPM development, implementation and ongoing operation remains a pressing issue. We look forward to continuing to work with the Authority and Commerce Commission to resolve this matter.

Appendix A: Proposed TPM Guidelines

Q9.	**What are your comments on the drafting of the proposed guidelines? Are any aspects unclear or unworkable? Do the guidelines clearly convey the policy set out in appendix B?**

The 2019 Issues Paper draft Guidelines are a significantly better and more workable than the 2016 version.

We have challenged ourselves to consider afresh how we could make the Authority's proposal work. A significant focus of our review of the Authority's proposal has been on the draft Guidelines and what changes to them would be needed if the Authority were to adopt its current proposal.

We have identified a number of drafting and workability issues in the draft Guidelines that need to be resolved. These are highlighted in our clause-by-clause comments on the Guidelines in **Attachment B** of our submission. We would welcome the opportunity to work through these issues with the Authority and other stakeholders. Some of the issues remain from previous drafts of the Guidelines.

In our view it would be prudent for the Authority to undertake a technical drafting consultation once it has made final decisions on whether to replace or amend the Guidelines.

Appendix B: Reasons for policy positions in the proposed guidelines

General matters

Q10.	**Do these [Appendix B] provisions give Transpower sufficient flexibility to develop the TPM while ensuring that the intent of the guidelines is followed and that the interests of designated transmission customers are protected?**

We reiterate our submission on the Second Issues Paper that:

> *no bright line delineates the boundaries between the Guidelines and the TPM … care is needed to ensure the Guidelines direct Transpower by laying out clear principles for the TPM but does not unduly foreclose design options.*

The latest draft Guidelines provide greater flexibility for Transpower in some areas, including providing for Transpower to apply proxies to estimate the net private benefits of individual transmission customers when determining the benefit-based charges. However, we consider the draft Guidelines need further work to avoid over-prescription. The proposed re-openers for the benefit-based charges, for example, constrain Transpower unduly and over time would make the charges inconsistent with the definition of beneficiaries-pay in the Authority's Decision-Making and Economic Framework (**DMEF**).

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission.

Connection charge

Q11. Should the current guidelines on connection charges be largely retained or are changes required?

Connection charges should be retained in substantially the form they are now.

We agree with what we understand to be the intent of Additional Components A and B in the draft Guidelines (relating to connection charges), though not the execution. See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clauses 55 and 56).

Q12. Should first-mover disadvantage be addressed in the TPM, and if so, how?

The new Guidelines and TPM are an opportunity to address the first mover disadvantage for investments that are funded by one or a few parties through investment agreements. The problem arises because, currently, subsequent customers who benefit from those investments do not pay a capital contribution to them through transmissions charges.

We have suggested a change to the draft Guidelines to introduce a "funded asset charge", which is one way to tackle this problem. See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (proposed new clause V). We note however, such a change to the TPM could equally be resolved under the current TPM Guidelines.

Benefit-based charge

Q13. Do you think introducing a benefit-based charge for future grid investments will promote efficiency and the long-term benefit of consumers?

No. Transpower does not think a benefit-based charge for future grid investments will promote efficiency and the long-term benefit of consumers. Where BB charges may promote efficiency more than alternatives the impact is undone by making charges largely fixed and unavoidable, and introducing considerable new sources of dispute.

We are unable to agree with the Authority that introducing BB charges would have a significant and beneficial impact upon the Commerce Commission's grid investment approval processes, resulting in more efficient expenditure. Rather, we consider the Authority's proposal would put timely, efficient grid investment at risk. We find it difficult to agree with the Authority's analysis and submit that it is, instead, more likely to create sources of dispute and may incentivise parties to withhold information rather than share it.

It is, instead, more likely to result in the proceedings getting bogged down in private interests and disputes that hinder timely, efficient investment in transmission at the expense of security, reliability and wider economic and social wellbeing considerations (including responding to climate change). We note Axiom's view that:

> *if the proposal has any effect on the grid investment approval process, it is likely to be negative, since it would create more sources of dispute and generate incentives for parties to strategically withhold information.*

Where disputes over price outcomes hinder timely, efficient investment in transmission and generation, higher electricity prices (a disbenefit to consumers) and elevated greenhouse gas emissions are likely consequences.

Customers' BB charges would be based on the benefits that Transpower estimates they will receive over the life of an investment at the time that it is made. Actual benefits will diverge from estimated benefits over time – perhaps dramatically. Moreover, the initial allocations would also apply to any upgrades made many years later. It is hard to see how such a regime could be durable – a problem the Authority itself acknowledged in its First Issues paper. To illustrate some of the challenges with the proposed BB charges we have provided in **Appendix 3** some simplified case studies of how the charge might apply to (hypothetical) grid investment.

See our answers to Q2, Q4, Q44 to Q46, Q54, Q55, Q58 and Q59.

Q14. Should the cost of pre-2019 investments be recovered in some other manner than through the residual charge, and if so how? Which pre-2019 investments should be recovered in this manner? In particular, do you consider that the cost of some past investments should be recovered through a benefit-based charge?

We agree it is sensible to use a "wash up" charge (such as a residual charge or the current interconnection charge) to recover otherwise unallocated costs.

A pragmatic alternative for recovering the costs of pre-2019 investments would be to use some form of regionalised or tilted postage stamp charge.

Q15. Assuming that a benefit-based charge is to apply to at least some pre-2019 investments, to which such investments should it apply?

Application of a benefit-based charge to any subset of historical investments, including investments made between 2019 and implementation of the new TPM, would be arbitrary to a degree.

Q16. How should the covered cost of the investment be defined?

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clause 14.)

Q17. How should the covered cost of a benefit-based investment be recovered over time for pre-2019 investments and post-2019 investments? How much discretion should Transpower have to determine the method?

How Transpower recovers the cost of grid investments over time is a function of our regulation by the Commerce Commission. Whether the TPM should use a different time profile should be left to be determined as part of TPM development. Consideration would need to be given to the impact of the having different price paths for the TPM and under Part 4, e.g. it could result in a more volatile Residual Charge.

Q18.	**Should the guidelines require Transpower to adopt a net load or a gross load approach in determining customer benefits, or should flexibility be allowed?**

We consider that the Guidelines specifying elements of the benefit-based charge methodology such as this would be overly prescriptive, and could adversely impact on workability. The method by which Transpower determines net private benefits, including the proxies it uses for that, should be left to be determined as part of TPM development (as is currently proposed).

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clauses 19 to 24).

Q19.	**Should the guidelines distinguish between high-value and low-value investments?**

We agree that the Guidelines should differentiate between high-value and low-value investments and have simpler requirements for the latter (to the extent the Guidelines have that level of prescription). We agree that the $20m threshold proposed for a high-value investment is appropriate.

If the Guidelines are to include a high-value investment threshold then that threshold should be applied consistently. The investment value threshold for reassignment (to the extent reassignment is retained) should be $20m, not $5m as proposed.

Q20.	**If so, should the costs of low-value investments be allocated via the residual charge or via the benefit-based charge using a simple method?**

A pragmatic alternative for recovering the costs of low-value investments would be to use some form of regionalised or tilted postage stamp charge (as also suggested in our answer to Q14 for all pre-2019 investments).

We consider that if the Guidelines include a requirement to apply the benefit-based charge to low-value investments there should be a discretion for Transpower to include a floor, as the administrative cost and effort of applying even a simple method to a very low-value investment is unlikely to be worth it. The costs of very low-value investments (below the floor) would be recovered through the residual charge or through an alternative charge as suggested above.

Q21. What is an appropriate threshold between low-value investments and high-value investments? Does it depend on whether the cost of low-value investments is recovered through the benefit-based charge?

See our answers to Q19 and Q20.

Q22. What are your views on the Authority's proposal to determine a benefit allocation for seven major existing investments (including the proposed and alternative methods)?

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clause 21).

Q23. How should the costs of the investments that are not covered by the benefit-based charge be allocated?

See our answers to Q14 and Q20.

Q24. Should charges be revised if there has been a substantial and sustained change in grid use? If so, what threshold would be appropriate to define such an event?

If the Authority's proposal were implemented, Transpower would be required to allocate BB charges to customers based on our estimates of the benefits they will receive over the life of an investment at the time that it is made. Our customers' collective utilisation of the grid is constantly changing, and over time that change can be fundamental to what benefits (or disbenefits) are realised by individual customers. Inevitably, any forecast of benefits that will arise over several decades will be wrong. In our considered view, the probability of the benefits estimates proving to be right, or materially right, over the 30 to 50 year life of an interconnected grid investment is low.

For example, it is relatively easy to deduce that upper North Island consumers would be 'immediate' beneficiaries from our proposed Waikato and Upper North Island Voltage Management project. However, once we start to get more granular and look further into the future, things get more complex. For instance, it is very challenging to forecast how the relative benefits of the investment would accrue between consumers in Top Energy's network relative to consumers in Vector's network, say, ten or twenty years from now.

This is not a reason to never change the TPM. Rather, it is a reason to ensure the TPM can adapt in response to change. BB charges can be designed to adapt. For example, adopting a method consistent with that applied in the United States (**US**) would go some way to achieving this. There, charges are fixed ahead of time to large beneficiary zones and then on-charged to individual parties (in the US context these are generally transmission owners) who themselves on-charge using traditional tariff structures, including peak charges. A similar approach in New Zealand would, in our view, significantly improve the chances of a successful move to BB charging.

To illustrate some of the problems and challenges with the Authority's proposed BB charges, we have included in **Appendix 3** of our submission some case studies for how the charge might apply to an upgrade of our transmission line between Wairakei and Hawke's Bay (hypothetically).

In our view, the alternative approach reflecting US precedent we have recommended above is likely to prove more workable and reasonably durable. In contrast, a highly granular approach that sought to lock-in charges and seldom – if ever – revisit them would have very little chance of being sustainable in the long-term. The Authority conceded as much in its first issues paper.

Whether or not the Authority adopts this alternative approach, the Guidelines should adopt the principle that the allocation of a benefit-based charge may change whenever there is a material misalignment between net benefits and the allocation, regardless of the cause of that. That would be consistent with the definition of "beneficiaries-pay" in the Authority's DMEF.

The draft Guidelines instead include a series of ad hoc provisions allowing for reallocation, or reassignment, in specific circumstances. The substantial and sustained change in grid use reopener in clause 26 is an example of that.

We note that the clause 26 reopener only applies to high-value investments, which risks significant benefits-to-allocation misalignment over time for low-value investments. We also note that "grid use" is not the only determinant of benefits. For example, the higher wholesale electricity prices over 2018-19 mean that if these dates were selected the proposed Schedule 1 allocations could be substantially different (higher for generators and lower for load) to the allocations the Authority has calculated based on 2014-18 data.

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clauses 17, 18, 25, 26, 32(b) and 42 and alternative clauses XA to XC).

Q25. Should the implementation of the charges for low-value post-2019 investments be deferred, and if so, for how long?

See our answer to Q20.

If the Guidelines apply the benefit-based charge to low-value investments we agree the implementation should be deferred in favour of implementing the charge for high-value investments. We agree that a five-year deferment deadline is appropriate.

Q26. Should the guidelines allow for reassignment of costs from the benefit-based charge to the residual charge? What are your views on the proposed reassignment provisions?

"Reassignment" is optimisation, but without using that word. In our view the Authority has not addressed the principal issues we have raised previously about optimisation of benefit-based investments. Those are:

- we consider the potential efficiencies of optimisation do not justify the administrative burden of it; and
- we are not aware of any established or accepted method of applying optimisation to assets valued on an historical cost basis. We consider this to be a major workability risk with the draft Guidelines.

Our position has not changed from our submission on the Second Issues Paper:

> *We consider that the [reassignment] provision in the proposed Guidelines should be removed. We recommend that this is replaced by a cap that limits [benefit-based] charges to aggregate positive net benefits.*

What is relevant is whether total net private benefits from a benefit-based investment is higher or lower than the total cost of it. There can be situations where, for example, an asset is "gold-plated" (and would be reduced in value under optimisation) but its benefit still exceeds its cost. In that case no optimisation, reassignment or other adjustment is necessary.

As well as avoiding the need for reassignment/optimisation clauses in the Guidelines, a cap on the benefit-based charge at total net private benefits would be consistent with the definition of beneficiaries-pay in the DMEF. This was a core element of the Authority's proposal in the First Issues Paper. We are unclear why the Authority moved away from this.

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clauses 33 to 38).

Residual charge

Q27. Should the guidelines provide for a single residual charge or multiple residual charges?

We do not consider that there should be more than one residual charge, but in our view the Authority should consider an additional regional or tilted postage stamp charge for pre-2019 and/or low-value investments. See our answers to questions 14 and 20.

Q28. Should any remaining MAR be recovered through a fixed residual charge? Should the residual charge be allocated based on a customer's historical electricity demand?

See our answer to Q34.

Q29. Should the residual charge be allocated based on AMD, annual consumption, a mixed approach, or some other approach?

See our answer to Q34.

Q30. If the residual charge is to be allocated based on AMD, how should multiple points of connection be treated?

See our answer to Q34.

Q31. Should demand be measured using a net load or gross load approach for the allocation of the residual charge?

See our answer to Q34.

Q32. If a gross load approach is used for the residual charge, should injection by both distributed generation and behind-the-meter generation be taken into account, or distributed generation only?

See our answer to Q34.

Q33. Is there any other available data that should be used to allocate the residual charge instead of data from the Reconciliation Manager?

See our answer to Q34.

Q34. Should the Authority determine the initial allocation of the residual charge in advance as a default or required allocation in the guidelines?

Questions 28 to 34 relate to question 10 in terms of the balance between prescription and flexibility in the Guidelines.

In our view the residual charge allocation methodology should not be determined as part of the Guidelines. We reiterate our submission on the Second Issues Paper that:

> *it would be better to specify that the Residual Charge is required to be set in a way that, to the extent practicable, is as fixed (unavoidable) and 'incentive-free' as possible, and leave the determination of the allocator to be adopted (be it physical capacity, as currently prescribed, or some other allocator) to the subsequent stage when the methodology itself is designed.*

The use of historic AMD the Authority is proposing would rate highly in terms of being fixed and unavoidable, but would benefit regions with high growth rates and discriminate against lower growth regions. If a rolling average AMD were used instead, it would be less fixed and unavoidable, but less prone to substantial changes to demand rendering the charges out-of-date or discriminatory. Historic AMD is not cost-reflective, as it does not differentiate between maximum demand that is peak (and contributes to capacity requirements) and off-peak (which does not contribute to capacity requirements).

These are examples of the trade-offs and factors that would need to be taken in account in determining an allocator for the residual charge. We consider they are best left to be considered as part of the TPM development process.

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clauses 39 to 41).

Q35.	**Should a customer's residual charge allocation be adjusted to account for a substantial change to demand due to factors over which it has no control?**

In principle we agree the residual charge allocation should respond to demand changes, but the need for a standalone adjustment mechanism depends on the residual charge allocation methodology that is adopted (i.e. it may be "self-adjusting if we are given sufficient flexibility to design it that way – see our answer to Q34).

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clauses 41 and 42 and alternative clauses ZA to ZC).

Q36.	**Should the residual charge apply to both generation and load customers, or only to load customers?**

One of the problems with the current TPM identified by the Authority is that generators do not contribute to the costs of interconnection assets they benefit from due to their location. As we have suggested in **Appendix 1** of our submission, one way to address that problem (as an alternative to a benefit-based charge) would be to require generators to pay part of the current interconnection charge or some other residual-type charge.

Other

Q37.	**Are the proposed provisions relating to adjustments appropriate?**

See our answers to Q23 and Q28 to Q34.

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clause 42 and alternative clauses XA to XC and ZA to ZC).

Q38.	**Should the guidelines specify that a prudent discount applies for the life of the relevant asset unless the parties agree otherwise? Should they specify a different period?**

The proposal that prudent discounts apply for the life of the relevant asset has not been justified. There is no evidence or assessment of problems with the current prudent discount arrangements.

There should not be a default period of the remaining life of the investment (which investment?) because the conditions that applied when the prudent discount was agreed may not be enduring. As clause 48 is drafted, customers will be able to force inappropriately long prudent discounts. In our view the period should be whatever the parties agree it is.

Q39.	**Should the TPM include a price cap? Does a price cap of 3.5% of total electricity bills provide a reasonable balance between the desirability of limiting price shocks and the desirability of transitioning to the new TPM?**

See our answer to Q40.

Q40.	**Should the price cap be specified as a percentage of electricity bills or in some other way?**

We reiterate our submission on the Second Issues Paper Supplementary Consultation:

> *The process to date has shown the potential for very large transfers, some of which have the potential to affect the viability of enterprise or the economic wellbeing of residential consumers. We consider there to be a need to include or retain transition provisions in the TPM Guidelines. We are open to the inclusion of a price cap. However, we have a number of practical and substantive concerns with the design of the price cap and its expression in the draft Guidelines.*

We support the inclusion of transition provisions in the Guidelines. However, our review suggests the design of the proposed price cap would neither prevent price shocks for our customers nor limit consumers' electricity price increases to (initially) 3.5% as intended. The cap would also have the unusual consequence of increasing the price rises that most load customers would otherwise face in its absence. Price caps normally work by delaying price reductions that customers would otherwise be facing in its absence.

The proposed price cap is not effective because it does not apply to all transmission charges. This means the price cap would not prevent price shocks. We provide, for clarity, some analysis of the proposed price cap mechanism in **Appendix 4** of our submission.

The Authority predicts that some of our distributor customers would face transmission charges increases of 100% or more and predicts large percentage increases for most of our direct-connect industrial customers.

The Commerce Commission tends to cap regulated price increases at between 5% and 10% to fulfil its statutory obligation to minimise undue financial hardship for suppliers and price shocks for consumers. Most of our customers who are predicted to face increases in their transmission charges would incur increases far in excess of 10%.

The choice to base the price cap on a percentage (3.5% initially) of the total consumer bill would not have the effect of capping increases in consumers' bills at that percentage, not only because the price cap does not apply to all transmission charges but also because the TPM does not control how distributors pass transmission costs onto their customers. The total consumer bill approach also introduces complexity and estimation error into the calculation.

Another choice, to use transmission charges for the 19/20 pricing year as the comparator for the price cap regardless of when any new TPM takes effect in prices, means the year-to-year price impact on our customers would be different to the indicative effect modelled by the Authority.

We submit that a better approach would be to apply the cap to all transmission charges and base the cap on a percentage of final year of transmission charges under the current TPM. Alternatively, the new transmission charges could be phased in in combination with the existing ones, similar to the transition from HAMI to SIMI for the current HVDC charge.

Another option is to remove the prescription about the price cap from the Guidelines and allow a suitable transition mechanism to be designed during TPM development.

We encourage the Authority to liaise with the Commerce Commission to ensure any TPM and Part 4 Commerce Act price cap and transition mechanisms are well co-ordinated and complementary. The Commission has recognised the potential for TPM change to be an issue in its price reset consultations.

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clauses 49 to 53 and alternative clauses Y and YA to YH).

Q41. Should the price cap apply only to load customers, or to generators as well?

See our answer to Q40.

Q42. How should the price cap be funded?

See our answer to Q40.

Q43. Are the proposed additional components appropriate? If not, what changes should be made?

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission (clauses 54 to 65).

Q44. Should the guidelines include a peak charge? If so, should it be a core component of the proposal or an additional component?

Transpower's view on this matter is well known. In our view, a peak price signal is needed for an efficient TPM. It should be a core component of the Guidelines.

The Authority's proposal appears to be unsympathetic towards retaining a peak pricing signal in the TPM. We submit that a peak price signal for transmission saves consumers money by deferring new transmission investment. Real-time nodal energy prices cannot do this job – as the Authority has acknowledged in the past. Opportunities to incentivise peak-demand management through the design of transmission charges should not be passed up in favour of more expensive alternatives, such as paying for demand response as a transmission alternative or through the wholesale energy market.

We agree with the Authority there might be benefits to be obtained from reforming the current (RCPD) peak pricing signal in some way, (such as 'weakening' the strength of the signal and/or making it more targeted). However, our analysis strongly reinforces our belief that the long-term risks associated with removing entirely all peak price signalling from the TPM far outweigh any potential near-term benefits. We believe that dynamic efficiency benefits from peak-pricing outweigh any allocative efficiency benefits from their removal. Put another way, the potential long-term economic costs from having a peak signal that is 'too weak' outweigh the near-term costs associated with a signal that is 'too strong'.

We also do not accept the Authority's claim that nodal prices alone can result in efficient short-term grid usage decisions *and* the right long-term investment outcomes, thereby obviating the need for a peak price signal in the TPM. This contention is not only at odds with widely accepted economic theory (as Axiom details in its report), it is also inconsistent with what the Authority has said in the past (when it supported unambiguously the economically orthodox position) and what it continues to say in the context of distribution pricing (where it is encouraging peak pricing).

Even if there are some parts of the grid with excess capacity at present, it does not follow that all peak pricing signals should be removed permanently. We would be open to modifying the existing signal. But removing it in all locations would, in time, spur peak demand growth and bring forward generation, distribution and transmission investment costs. Without a peak signal, we would not be able to efficiently defer those costs, or the increased greenhouse gas emissions that they would bring.

We are firmly of the view that permanent peak pricing in the TPM is vital, particularly to support the electricity industry's climate change response.

Q45. Should the peak charge be applied only where the grid would otherwise be congested?

As noted in our answer to Q44, we support consideration of options to target the current RCPD peak pricing signal to areas where transmission investment is most likely to be needed. This could include having varying strengths of peak-pricing signal for different areas.

Q46.	**Should the peak charge be permanent or should it be phased out? If the latter, should the default phase-out period be over 5 years, 10 years or some other period?**

See our answer to Q44. We consider it very important that a peak price signal is retained in the TPM indefinitely. We note that:

- The type and level of responses to a temporary peak charge can be expected to be weaker than for an indefinite peak charge as market participants would be less willing to make investments with only a short pay-back period.
- It is incorrect to describe the proposed transitional peak charge option as a "phase out" of the current peak charge. Clauses 58 to 61 of the draft Guidelines would require us to develop a new peak mechanism and then phase it out. Regardless of the merits of peak-pricing, we question whether the cost of doing this would be a good use of Transpower's resources, particularly given the many other challenges we will face in developing the new TPM in line with the draft Guidelines.

If transitional peak pricing arrangements were applied it should be on a pragmatic basis that reflects the limited timeframe they would apply for. This could include, for example, continuation and phase-out of the RCPD charge but on a more targeted basis.

Q47.	**Should the guidelines make applying the benefit-based charge to additional and potentially all pre-2019 investments a core component?**

See our answers to Q14 and 15.

Q48.	**In addition to the specific questions above, do you have any further comments on the matters covered in this appendix B?**

See our clause-by-clause comments on the Guidelines in **Attachment B** of our submission.

Appendix C: Material change in circumstances

Q49.	**Do you have any comments on the matters covered in this appendix C?**

Appendix D: Elaboration of decision-making and economic framework

Q50.	**Do you agree that the analysis presented in chapter 5 of the second issues paper remains appropriate?**

We do not consider the content of Appendix D of the 2019 Issues Paper to be an "Elaboration of [the] decision-making and economic framework". It appears the Authority has effectively replaced the DMEF with new tests that the TPM be "cost-reflective" and "service-based".

Q51. Do you agree that workably competitive markets provide an appropriate analogy for deriving principles for efficient pricing of the interconnected grid?

We agree with this in principle, but do not consider the Authority's proposal to be analogous with workably competitive markets.

In Appendix D the Authority correctly states that:

> *in workably competitive markets, prices paid by customers are typically no more than the benefit the customers get from the service and on average equal to the cost of providing the service.*

However, this does not mean or require that prices are set on the basis of estimated benefits.

In workably competitive markets, if the (cost-based) price of a good or service exceeds the benefit to the consumer they will not buy it. If a firm tries to engage in first degree price discrimination, which the Authority's proposal would require Transpower to do, and they get it wrong they lose customers to alternative suppliers. For example, if Air New Zealand misjudges the scarcity value of seats on peak-time flights it risks flying with an excess of empty seats, but is able to adjust its pricing to minimise the risk of repeating the same mistake for future flights.

This is not Transpower's situation. As a provider of a natural monopoly service, if Transpower gets it wrong (or the Authority with Schedule 1) and sets prices higher than net private benefit, the transmission customer would bear the cost. The only thing certain about setting charges on the basis of individual customer expected net private benefit over the life of an investment is that Transpower will get it wrong.

The divide between workably competitive markets and the Authority's proposal is highlighted vividly by the Authority's comment on its website that:

> *If the owner of the generation asset was continuing to be a transmission customer, then closing down one of its generation assets wouldn't generally lead to a change in charges. The owner would continue to be liable for the same level of charges for which it was previously liable. The reason for this is to avoid distorting the owner's incentives: the intention is that the owner should not have an incentive to shut down a generation asset arising due to the avoidance of the benefit-based charge or the residual charge. These are intended to be fixed charges that do not vary based on a party's use of the grid.*

In a workably competitive market, a firm would not be able to continue to charge for a service the customer is no longer using. Only a monopoly could do that.

Q52. Do you agree with the conclusions of appendix D?

See our answers to Q50 and Q51.

Q53. Do you have any comments on the matters covered in this appendix D?

See our answers to Q50 and Q51.

Appendix E: Assessment of alternatives

Q54. Do you agree with the conclusions we draw from Transpower's report *The role of peak pricing for transmission*?

No. As noted in our answer to Q44, the analysis we presented in our report strongly reinforces our belief that the long-term risks associated with removing all peak price signalling from the TPM far outweigh any potential near-term benefits.

Q55. Do you agree that nodal prices enhanced by RTP, and supplemented if necessary with administrative demand control, are the most efficient means of constraining grid use to capacity?

We do not agree this is the correct question to ask in relation to whether the TPM should retain peak pricing signals. The purpose of peak pricing in the TPM is not to efficiently constrain grid use to capacity.

Nodal pricing and administrative demand control can be useful for managing short-term demand and capacity constraints only. Transpower does not see the principal role of the TPM as managing short-term demand fluctuations. In our view, the focus of peak pricing signals in the TPM is longer-term (dynamic efficiency) on future investment and capacity requirements.

The Authority has articulated well, in the context of distribution pricing, that what is important is the impact absence of peak pricing signals could have on peak demand and the need to bring forward/increase investment in network capacity.

We consider the impacts and risks of removal of peak pricing on long-term grid investment and price levels, not short-term demand, should be the primary focus of the Authority. This would be consistent with the Authority's position that dynamic efficiency is more important than short-term efficiency.

Q56. Do you agree that the benefit-based charge, in conjunction with the Commerce Commission regulatory regime and nodal prices, is sufficient to ensure efficient investment in the grid and by grid users?

No. See our answers to Q54 and Q55.

Q57. Do you agree that nodal prices (supplemented if necessary by administrative load control) will be allowed in practice to efficiently restrain grid use to capacity?

No. See our answers to Q54 and Q55.

Q58. Do you agree that it would not be efficient to provide for a permanent peak based charge in addition to nodal prices?

No. We instead agree with the views the Authority expressed in its LRMC Working Paper.

In the LRMC Working Paper, the Authority explained in an orthodox and non-contentious manner that "… charges based on LRMC could promote dynamic efficiency" and "… nodal prices are likely to under-signal LRMC so LRMC charges could potentially promote more efficient investment". The Authority detailed why nodal pricing was not adequate and would under-signal:

> Some authors, such as Associate Professor James Bushnell of the University of California, Davis, who provided advice to Trustpower on the beneficiaries-pay working paper, suggest that nodal pricing is all that is required to promote efficient investment in relation to transmission. This appears to be based on a view that nodal pricing provides price signals that reflect both the SRMC and the LRMC for transmission. However, nodal pricing is likely to result in price signals systematically below LRMC for the following reasons:
>
> (a) the SRMC of the use of the transmission network is signalled through differences in nodal prices – but if spot prices do not reflect the true value to customers of lost load, price differences will at best send a muted signal of the true marginal cost of the transmission network. While scarcity pricing has been introduced in New Zealand, its application is limited to separate scarcity prices for the North and South Island, so the value of lost load at a more disaggregated level is still not priced. This means within-island price differences, at least, send a muted price signal below the true marginal cost of the network
>
> (b) transmission planners err on the side of caution in determining the transmission capacity required to meet future demand
>
> (c) the grid reliability standards (e.g. the N-1 standard for the core grid) are independent of economic costs. To the extent the core grid extends to remote locations, the same reliability standards are applied to remote and centrally located customers
>
> (d) lack of competition may lead to overbuilding transmission in an attempt to address competition problems
>
> (e) over-building of transmission may be justified for reasons of national security
>
> (f) economies of scale in transmission mean transmission is commonly overbuilt, and the amount by which overbuilding reduces SRMC below LRMC is considerable. This means it is impossible to match transmission capacity precisely with transmission requirements at all times.
>
> Since most of these reasons apply in New Zealand nodal prices are likely to under-signal LRMC so LRMC charges could potentially promote more efficient investment. However, while LRMC charges may be appropriate, nodal pricing will still provide some signal of marginal cost, albeit muted.

Q59. Do you agree that the proposed transmission charges are more efficient than the options discussed here? Are there any other options we should consider?

In our view the Authority should address the problems it has identified with the current TPM through incremental reform.

The table in **Appendix 1** of our submission provides some examples of incremental reform options that could address the problems the Authority has identified with the current TPM.

In our view, this type of reform has significant advantages over the "root and branch" type reform of the Authority's proposal. It is faster and less expensive to implement, bringing the reforms to the market more quickly, and there is a lower risk of unintended consequences.

The Authority has previously noted (most recently in response to the EPR's hedge market reform proposals) that major regulatory changes carry a risk of unintended consequences and should be approached cautiously. For example, in the context of the Authority's proposal, there is a risk that the BB charge could inefficiently distort the wholesale electricity market and generation investment decisions. One concern we have is that the BB charge would send a signal to delay potential new generation until spot prices are not only high enough to cover the cost of the generation but also the new, and potentially uncertain, transmission charges. This would create windfalls (higher price benefits) for generators operating in areas that are subject to lower BB charges.

Q60. Do you have any comments on the matters covered in this appendix E?

See our answers t Q54 and Q59.

Appendix F: Potential changes to the Code

Q61. Should LCE be allocated to the specific investments to which it relates? If not, how should it be allocated?

As we submitted in response to the Authority's RTP Remaining Elements Proposal (April 2019), given that the FTR grid is an increasingly close approximation of the whole grid, we do not think the administrative cost of having Transpower allocate residual LCE (the part of total LCE not required for the settlement of FTRs) is justified. The task of allocating residual LCE should go to the clearing manager, who could allocate it to wholesale market purchasers in proportion to their payments as part of the normal monthly clearing process.

If Transpower is to continue to allocate residual LCE, we recommend the following changes to proposed clause 14.35A (assuming the draft Guidelines are issued):

14.35A Allocation of loss and constraint excess

(1) A **grid owner** must allocate any **loss and constraint excess** (including **residual loss and constraint excess**) it receives in a pricing year:

(a) amongst grid assets ~~investments~~ in proportion to the **loss and constraint excess** generated by each grid asset ~~investment (including investments whose cost is recovered through the residual charge)~~; and

(b) in respect of each grid asset that is a connection asset or part of a benefit-based investment ~~(other than grid assets whose cost is recovered through the residual charge)~~, amongst **designated transmission customers** in proportion to the transmission charges they pay in that pricing year in respect of that grid asset ~~investment~~; and

(c) in respect of each other grid asset ~~investments whose cost is recovered by the residual charge~~, amongst **designated transmission customers** in proportion to the residual charge they pay in that pricing year.

(2) This allocation methodology is deemed to be the prevailing methodology for distribution of loss and constraint excess payments for the purposes of the **benchmark agreement** and every **transmission agreement**.

(3) In this clause, "pricing year", "grid asset", "connection asset", "benefit-based investment", "transmission charges" and "residual charge" have the meanings set out in the **transmission pricing methodology**.

We note:

- Transpower allocates residual LCE on an asset basis, not an "investment" basis. A single investment may involve more than one grid asset.
- The benchmark agreement is not itself a transmission agreement (i.e. the contract for connection to and use of the grid between Transpower and its customer).

Q62.	**Would the proposed ACOT Code change be desirable to clarify the situation for payment of ACOT under the TPM proposal? Would the resulting code provisions in relation to ACOT be efficient?**

We note that:

- the proposed change to clause 2(a)(i) refers to an area-of-benefit charge instead of the benefit-based charge; and
- it should be clarified that the charges referred to in clause 2(a)(i) are defined in the TPM.

We support the proposed revocation of clauses 2A to 2C of schedule 6.4 and the consequential changes.

Q63.	**Do you agree that this potential Code amendment to ensure the workability of the TPM will reduce uncertainty? If not, do you think it can be modified so as to ensure uncertainty is reduced? If so, how?**

In our view, any post-implementation workability issue would be better dealt by way of a Transpower operational review rather than a review by the Authority under proposed clause 12.86(b)(i).

Operational reviews are already available under clause 12.85, although the 12-month interval rule would be problematic if the issue were discovered within a year of implementation of the new TPM. That problem could be eliminated by adding the following words to the end of clause 12.85:

> *(unless otherwise approved by the Authority, having regard to the reason for the proposed variation)*

Proposed clause 12.86(b)(ii) goes beyond workability and is not discussed in the 2019 Issues Paper. In our view, a new right for the Authority to re-open the TPM on vague "policy objective" grounds would introduce too much uncertainty into transmission pricing, affecting both Transpower and its customers. The Authority needs to consider its policy objectives when it is preparing the Guidelines and when it is deciding whether to approve the proposed TPM, in each case within the confines of its statutory objective. Proposed clause 12.86(b)(ii) should not be added to the Code.

Q64. In addition to the specific questions above, do you have any further comments on the matters covered in this appendix F?

No.

Appendix G: Response to some criticisms

Q65. Do you have any comments on the matters covered in this appendix G?

None beyond those covered in answer to the other questions and in our submission more generally.

Appendix H: Method and assumptions: impact modelling and proposed benefit allocation

Q66. Over what period should we undertake the vSPD modelling?

See our answer to Q70.

Q67. Should the vSPD modelling adopt a fixed VPO or a variable VPO? In either case, what is the appropriate level of the VPO?

See our answer to Q70.

Q68. Do you agree with the approach we have taken to net distributed generation? Do you agree with the application of our netting policy for particular generator(s)? If not, please provide details of particular generator(s) so that we can consider whether to amend our netting arrangements.

See our answer to Q70.

Q69. Do you consider that the data used in the impacts modelling (in particular, demand and generation volumes) should be adjusted? If so, please provide reasoning/quantitative calculations.

See our answer to Q70.

Q70. In addition to the specific questions above, do you have any other comments on the matters covered in chapter 5 and this appendix H, including in particular: the indicative year-one transmission charges in chapter 5; and the allocation of annual benefit-based charges for the seven major investments included in schedule 1 of the proposed guidelines (appendix A)?

We consider questions 66 to 70 to be matters most appropriately responded to by our customers who will be directly impacted by the Schedule 1 allocations for the historical investments.

We are aware that issues were raised with the Authority's vSPD method in response to the First Issues Paper, many of which would still be relevant and should be considered. Subsequent to the First Issues Paper, the Authority withdrew its proposal to mandate the vSPD methodology as part of the Guidelines, so subsequent Authority indicative prices (and the methodology used to produce them) did not receive significant focus in submissions.

See our clause-by-clause comments on the Guidelines in Attachment B to our submission (clause 21).