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CONSULTATION PAPER: PROPOSED TRANSMISSION PRICING METHODOLOGY

1. INTRODUCTION

1.1. Background

1.1.1. Thank you for the opportunity to comment on the Electricity Authority's (**the Authority's**) 8 October 2021 Proposed Transmission Pricing Methodology Consultation Paper (**Consultation paper**).

1.1.2. The Consultation Paper recommends an amendment to the Electricity Industry Participation Code (**the Code**) to replace the current transmission pricing methodology (**TPM**) with a new methodology.

1.1.3. The Authority is seeking general feedback on its proposal as well as responses on particular features of the proposed TPM.

1.2. Structure of our submission

1.2.1. Our submission comprises:

a) This cover letter where we explain why we consider:
   - the proposed TPM is not in the long-term interests of consumers; and
   - the Authority has not yet met the requirements of section 39(2) of the Electricity Industry Act 2010 (**the Act**) for this Code amendment.

b) Four appendices:
   - Appendix A which responds to the Authority's consultation questions;
   - Appendix B which contains an expert report from Creative Energy Consulting (**CEC)** which examines the impact of the proposed TPM on the investment and operations of different types of transmission customers relative to alternative charging approaches (**the CEC 2021 Report**);

- Appendix C which provides a summary of the Authority's TPM reform analysis prior to consultation on this Code amendment including its analysis of alternatives and cost benefit analysis (**CBA**) results; and
- Appendix D which contains an expert report from HoustonKemp which reviews the CBA produced to support this Code amendment (**the HoustonKemp 2021 Report**).

1.2.2. Our submission also draws on the expert reports which have been filed during prior consultation on TPM reform.

2. NATURE OF PROPOSED TPM

2.1. Core proposal involves aggressive redesign

2.1.1. The Authority is concerned that the variable regional coincident peak demand (**RCPD)** charge in the current TPM:

a) denies consumers access to the grid at peak times when it would be useful to them; and

b) creates an ongoing risk of inefficient (and potentially carbon-emitting) investment in distributed energy resources.

2.1.2. It is also concerned that a socialised approach to transmission costs does not promote:

a) efficient investment by load and generation; and

b) grid scrutiny by providing incentives for more active participation by transmission customers in the Commerce Commission's scrutiny of Transpower's expenditure proposals.

2.1.3. To address these issues the new TPM involves "*aggressive redesign*"[1] of the current structure of transmission charges.

2.1.4. At the core of this redesign, is a proposal to replace the current transmission charges with what is in essence a three-part pricing structure:

a) variable charges arising from the nodal prices in the wholesale market;

b) benefit-based (**BB**) charges to provide supplementary price signals for locational decisions and increase scrutiny of transmission investments; and

c) residual charges to recover the costs of most pre-2019 assets and common costs.

2.1.5. It is axiomatic that such a radical change needs to be well justified.

2.2. Long term impact of removal of variable (RCPD) charge

2.2.1. As part of its justification, the Authority developed a bespoke model in 2019 to assess *the size of the benefit o*f removing the variable RCPD charge. Following feedback, elements of the model were substantially amended in 2020.

2.2.2. The Authority's decision to adopt the TPM Guidelines was based on its 2020 CBA which was released contemporaneously with its decision. The 2020 CBA was said to correct the errors we and others had pointed out in relation to the Authority's 2019 CBA.

2.2.3. The increased grid use benefits (associated with the removal of the RCPD charge) identified by the Authority in 2020 were:

a) a change in consumer welfare from increased use of the grid at peak times ($1,131m); and

[1] Bushnell and Wolak "Beneficiaries Pay pricing and "market like" transmission outcomes, February 2017 at p1

b) the avoidance of inefficient battery usage ($51m).

2.2.4. In the 2020 CBA, the Authority assessed the extra consumer usage at peak times at around 1.2% more on average. If you dug into the analysis you would have found that this additional peak demand resulted in a slight rearrangement of the timing of the commissioning of 11 generators.

2.2.5. However, the Authority claimed that such investment would give rise to reductions in wholesale prices due to the retirement of thermal plant and the commissioning of lower cost renewable energy, and result in very large consumer benefits.

2.2.6. Our experts advised that the claim of substantial consumer benefits arising from this slight re-arrangement of the generation stack was a methodological error. This is readily demonstrated by the small cost saving arising from the proposal. A review by HoustonKemp assessed the cost saving as $5m of reduced costs of generation. The Authority also points to $37m of reduced operating costs (which to our mind should be offset by $32m in investment costs)

2.2.7. Whichever number you use the results of the Authority's modelling are not plausible. If costs reduce by $5m (or $37m), it is nonsensical to suppose that consumers would end up paying prices so much lower that they derive $1,131m of benefit from them.

2.2.8. Our view, which we have shared with the Authority, is that the Authority's experts have modelled transfers (artificially low prices to generators) not efficiency benefits. This suggests its case for reform of the RCPD charge was much overstated.

2.2.9. The Authority has now updated its modelling and found that with new input assumptions, the extra consumer usage at peak times will be around 3.5% more on average. To meet this demand 68 extra generators will now need to be commissioned over the period modelled (as well as additional transmission and distribution costs incurred). Trustpower's expert's comments on this new CBA are discussed in section 4.4.

2.2.10. We note that a great deal rides on the Authority's confidence that new generation entry will occur at the times and prices modelled in its latest CBA. If the Authority is wrong, the removal of the variable RCPD charge will create extra consumption at peak times that triggers irreversible extra costs across the entire supply chain. This is a bold gamble to make on behalf of consumers.

2.2.11. We also think it is disappointing that the Authority has not used a consistent approach in its CBA modelling. The changes to the 2019 CBA, 2020 CBA and 2021 CBA and ongoing reluctance to model credible alternatives to the preferred proposal create the impression that the Authority is using its CBAs to support its preferred solution rather than to find the best solution.

2.3. RCPD removal also creates reliability and affordability risks in the short term

2.3.1. In addition to the long term impacts, the abrupt removal of the RCPD charge creates reliability and affordability risks in the short term.

2.3.2. The winter 2021 peak demand records (on 29 June, 9 August and 15 August) are a timely reminder that new generation builds are overdue and energy security can't be taken for granted.

2.3.3. In the current climate we are particularly concerned that the Authority sees load control as an adequate means of controlling congestion and is not concerned at the prospect the new TPM will trigger higher prices.[2]

2.3.4. A staged introduction of this change would have gone a long way to mitigate the energy security risks consumers now face.

[2] Refer to Transpower's January 2020 TPM Development Checkpoint 1 resubmission: Transitional Congestion charge.

2.4. Benefit based charges are not the best solution

2.4.1. The case for BB charging rests on the presumption of increased investment efficiency.

2.4.2. Trustpower struggles to understand how the Authority can consider that nodal prices in New Zealand work very well, sending perfect signals for efficient use and investment, such that any peak charge placed on top of this would be 'distortionary'; yet at the same time promote the introduction of BB charges to ensure that customers take into account the cost of future investments in making decisions on use of the grid, or submissions on future investment.

2.4.3. Axiom Economics in 2019 (for Transpower) considered this makes little sense[3]:

> *…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? …*

2.4.4. We agree with Axiom. If nodal prices do work perfectly, then it would be inefficient to change customers' decisions, so a non-distortionary charge (like the residual charge) should be used to recover the remaining transmission costs.

2.4.5. Nevertheless, the Authority's CBAs claim that BB charges will result in:

a) More efficient investment from load and generation ($40m in the 2020 CBA and $106m in the 2021 CBA); and

b) More efficient grid investment arising from increased scrutiny ($49m in the 2020 CBA and $47m in the 2021 CBA);

2.4.6. In previous submissions we have explained why we do not think this is likely in practice and why we do not think the Authority can rely on its estimate of the value of these benefits. Our views have not changed.

2.4.7. If investment efficiencies continue to be a priority, then we would like to understand why the Authority prefers an opaque and hard to forecast BB charge over a direct price signal of future transmission investments such as would be provided by a heuristic LRMC charge. Again, this makes little sense.

2.5. The new TPM will harm, not promote, competition

2.5.1. The Authority claims that BB charges promote competition by providing a level playing field between different types of generation and will also promote durability by ensuring that "*what you pay for is what you get*".

2.5.2. To our mind this is a case of "*what you see in the picture is not what is in the box*".

2.5.3. The new TPM is riddled with discriminatory treatment of transmission customers. This includes proposals to charge:

a) selected connection charge counterparties for anticipatory capacity;

b) schedule 1 "*beneficiaries*" on the basis of an allocation which Transpower considers is likely to become an increasingly unreliable way of estimating forward-looking benefits;

c) later entrants with backdated BB charges, which will unfairly overcharge those entering who genuinely always planned to enter later and/or discourage those who seek to use the new, spare transmission capacity that has been created by the project;

d) trailing exit charges, whereby some parties are charged for some years after they have left the market;

[3] Axiom Economics 2019 Report, page 6.

e) parties according to various de minimis thresholds, which in effect create a variable charge for larger but not smaller market participants;

f) parties according to various mechanisms for inter-regional and intra-regional adjustment to the BB charges, when there is no change to the benefits those customers receive from the relevant investment;

g) grid connected batteries in a bespoke manner not afforded to other load with similar characteristics; and

h) transmission customers in line with price path forecasts rather than back-loading cost recovery to more closely align with forecast usage.

2.5.4. Such discrimination is antithetical to competition and will lead to poor outcomes for consumers.

2.5.5. BB charges on generation are likely to vary substantially from generator to generator in ways that reflect Transpower's modelling of benefits rather than costs imposed on the transmission network. This approach will not lead to a 'level playing field' but will instead affect the willingness of efficient new generators to make investments to meet the surging demand that the Authority now anticipates.

2.5.6. BB charges on generators act as a tax on new entry – a tax that is higher for more efficient generators since they extract greater benefits from their entry into the market than less efficient generators. Higher BB charges on generators will reduce the rate of entry into the sector and drive-up wholesale prices. For example, the Authority's CBA indicates that wholesale electricity prices will increase by 10.8% as a result of its proposed TPM.

2.5.7. It's hard to see how the impacts of the BB charges on the generation sector will support New Zealand's decarbonisation objectives being achieved.

2.6. Responses to consultation questions

2.6.1. Our answers to the specific questions posed in the Consultation Paper on the mechanics of the TPMs design are attached in Appendix A.

3. IMPACT OF TPM DESIGN ON TRANSMISSION CUSTOMERS

3.1. Introduction

3.1.1. The Authority's 2020 strategy reset indicates that it wants "*consumer centricity*" to guide regulation and the industry (i.e. putting consumers front and centre in what it does and how it does it).

3.1.2. We therefore invited CEC to consider how the proposed TPM would impact the investment and operational decision-making of different types of transmission customers. A copy of CEC's 2021 Report is provided as Appendix B.

3.1.3. The next sections summarise the key findings in CEC's expert report from the perspectives of:

a) A customer seeking to incrementally increase its consumption;

c) A new load customer or an existing load customer making a step change in its consumption;

d) A new generation customer;

e) An existing customer seeking to engage in the transmission planning process in the manner desired by the Authority; and

f) A load customer seeking to cease supply or de-rate its plant.

3.1.4. These customer types have been chosen by CEC so as to avoid the repetitious identification of overlapping issues whilst highlighting the main features of the TPM from the perspective of Transpower's customers.

3.2. Customer seeking incremental increased consumption

3.2.1. CEC advise[4] that an existing customer seeking to increase its consumption by less than 10MW per annum will face *a mixture of fixed and variable transmission charges*:

a) BB charges relating to historical BB investments are fixed, whereas BB charges relating to future BB investments, within the relevant window, are variable, as is the Residual charge.

b) For each of the variable charges, payment lags consumption: service provision is, in effect, on a "*buy-now-pay-later*" basis.

   i. For the Residual charge it is simply the case of lagging payment by 4-8 years, which has the present value effect of reducing the transmission price by around 50%.

   ii. CEC note that Transpower does not suffer from this payment delay, by virtue of being permitted to, in effect, double-charge existing customers for their consumption over the years immediately prior to the TPM change: once under the old TPM regime and again, on a delayed payment basis, through the Residual charge.

   iii. For new BB investments, the payment timing is based on consumption for the few years prior to the time the BB investment is committed. This timing is reminiscent of an LRMC-style tariff, but unlike a conventional LRMC tariff, the BB charge methodology – and even the BB investments on which this is applied – are likely to remain uncertain to the customer at the time of their consumption: i.e. several years in advance of the BB investment commitment. This uncertainty will add substantial risk to customer decision-making and associated profitability.

c) Another challenge arises from the fact that each transmission customer's tariff will be different. Because the base level of charge depends upon the customer's any time maximum demand (**AMD**) over the baseline period, customers with lower load factors (i.e. proportionately higher AMD) will pay a premium price. Because these baseline AMDs are locked in, there is nothing the customer can do to change this [apart from large changes that trigger a reopener]: its Residual charge tariff will, for all time, depend upon what its load factor was over the baseline period.

d) Post 2019 charges are variable as BBI charges are applied to the region in which the customer is located, to which our customer's consumption contributes. Secondly, the metrics used to allocate that regional charge between customers in the region is also based on consumption. A customer wishing to answer the question of the impact of an incremental change in its consumption will need to track all of these causalities, through several BBI investments and associated BB charging methods and mechanisms.

3.2.2. The CEC 2021 Report concludes that this uncertainty will add substantial risk to customer decision-making and associated profitability and as a consequence *"it was remiss of the Authority not to have considered a conventional LRMC charge"*[5] which would have avoided these issues (and other design issues including those relating to the reopeners).

[4] CEC 2021 Report, pages 4-10

[5] CEC 2021 Report, page 10

3.3. New load customer (or customer facing a step change increase in load)

3.3.1. In contrast to an existing customer seeking to increase its consumption, a new load customer has the choice of location for its investment.

3.3.2. CEC advise[6] that this type of customer will see the proposed TPM as a *locational tariff* similar in effect to a tilted postage stamp charge but far more complex given the estimation risks.

3.3.3. The tariffs for new load customers rely on Transpower estimated metrics: AMD for the Residual charge and coincident and average demand for BB charges on historical BB investments.

3.3.4. CEC note[7] that it is not clear how Transpower would calculate these estimates, or what risks are created for new load customers as a result.

3.3.5. CEC consider[8] the Authority could have provided substantially the same long term incentives, without these risks by designing a tilted postage stamp charge.

3.4. New generation customer

3.4.1. The CEC 2021 Report notes[9] that a major issue for both connection and interconnection investments is sizing: should the new asset be *right-sized* to just accommodate the new entrant generator; or should it be *over-sized*, with some *excess capacity,* included, to economically provide for future entrants? And, if excess capacity is to be built, who should pay for it; and who should take the stranding risk, given that the anticipated future generation might never arrive?

3.4.2. This issue is exacerbated with the transition to renewables, since these projects, as well as being typically smaller than for conventional generation, are likely to cluster in geographical areas where renewable resources, land prices, transmission interconnection and planning conditions are all favourable, and multiple projects can be accommodated.

3.4.3. The TPM creates a first-mover problem where an entering generator triggers new investment (whether for connection or for interconnection) incorporating excess capacity for which it is required to pay the lion's share until later entrants arrive. This is contrary to the Authority's BB charging philosophy as it is future customers not current customers who benefit from excess capacity.

3.4.4. CEC suggest that left unchanged this feature of the TPM is likely to require correction due to its adverse impact on the energy transition[10]. This is because generators may delay entry due to the advantages of being a second or late mover. A late mover knows what any excess capacity looks like, as it is already built. At worst, it shares the burden with the earlier movers that are already there.

3.4.5. Generators are also adversely impacted by Transpower's decision to share costs 50/50 between load and generators in the simple method and to make other hard coded assumptions in the standard method models rather than undertake detailed modelling of revenue impacts of particular proposals on its transmission customers.

3.4.6. The Authority now forecasts that generators will pay more of the BB charges in the proposed TPM than in previous forecasts. In 2020 CBA generators were expected to pay transmission

[6] CEC 2021 Report, page 15

[7] CEC 2021 Report, page 17

[8] CEC 2021 Report, page 17

[9] CEC 2021 Report, page 18

[10] CEC suggests that it would be better for load to bear the initial costs and stranding risks of the new excess capacity through adjustments to the residual charge. Refer to CEC 2021 Report, pages 18-22.

charges of less than $100m per year but in the new CBA the charges increase to above $250m per year.

3.4.7. CEC note[11] that these sharing approaches to the BB charges have been adopted at the eleventh hour, with limited scrutiny, analysis or consultation; even the Authority is uncertain that it is the right approach and has flagged a future review. This represents "*a major failure of the TPM review process*".

3.4.8. A further failure relies from the Authority's unwillingness to rely on its own CBA in making this sharing decision.

3.4.9. The Authority's CBA estimates the benefits of an alternative TPM, in which generators only pay for 25 per cent of investments allocated under the simple approach, are over $**1 billion more** than the proposal preferred by the Authority.

3.4.10. The HoustonKemp 2021 Report comments[12]:

> *" If differences of this magnitude do not provide the Authority comfort that there is a sound empirical basis for its decisions, then it raises questions as to whether the Authority's reliance on its CBA in support of its proposed TPM is reasonable."*

3.5. Customer engagement in the planning process

3.5.1. A further effect of the design of a TPM which front loads costs on current users, is that existing customers have strong incentives to ensure that there is no, or minimal, allowance for excess capacity in transmission upgrades.

3.5.2. CEC comment that it is not clear:[13]

> *"…whether or how the two process of BBI commitment and BBC method are entwined. Does the BBC have to be decided prior to the BBI being committed? Or only after? Logically, for a customer to be able to engage rationally in the BBI design process, it must also know what share of the costs it will bear under different BBI project options. But tying the two processes together would make an already difficult planning process more complex and contentious. Any delays in urgently-needed investment will have real costs, of course: so a zero-sum game could have a negative-sum outcome."*

3.5.3. An underlying problem is that a key stakeholder is missing from the table: the future customer. This is why these decisions are usually left to independent planners and regulators who can act on their behalf.

3.5.4. CEC observe:[14]

> *"As we transition to a zero-carbon world, the needs and interests of future customers – whether in the form of new renewable generators or newly "electrified" energy consumers – loom ever larger. In this context, the EA's idea of putting existing customers in the driving seat for transmission planning is unhelpful and misconceived."*

3.6. Load Customer seeking exit

3.6.1. The TPM provides for different treatment for load customers who seek to reduce load and those who exit.

b) A marginal reduction in load faces the equal and opposite signal to the marginal load increase such that the "*buy now pay later*" becomes "*reduce now and save later*".

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[11] CEC 2021 Report, page 25

[12] HoustonKemp 2021 Report, page 3

[13] CEC 2021 Report, page 27

[14] CEC 2021 Report, page 28

c) However de-rating or exit will trigger different treatment depending on the scale of the load decrease. The distinctions are likely to trigger inefficient investment and operation decisions based on the bright lines.

3.6.2. CEC comment that:[15]

> *"By choosing to create this ramshackle, buy-now-pay-later TPM infrastructure, the EA has made a rod for its own back. As discussed in the previous chapters, conventional buy-now-pay-now tariff structures can provide similar incentives to the TPM, at least for the long-term decisions that really matter. That those simple, equivalent tariffs go by the name "Tilted Postage Stamp" shouldn't discourage the EA from adopting them, even at this late stage."*

3.7. CEC's overall conclusions

3.7.1. The CEC 2021 Report concludes that the final form of the TPM has involved a significant shift from the Authority's original vision of charges based on actual private benefits and the costs of sunk assets recovered from fixed charges that customers were unable to avoid.

3.7.2. This shift has occurred because, as we and others advised, the vision could never have been practically implemented in its purest form, because customers will inevitably enter and exit, and fairness and durability require that entering customers pay their fair share of sunk costs, whilst exiting customers cannot continue to be charged.

3.7.3. In attempting to improve the efficiency of both short and long run investment and operational decisions the new TPM is at risk of failing to do either due to its complexity and internal inconsistency (with different customer types having different mixes of fixed and variable charges).

3.7.4. CEC suggest[16] that at this stage in the process it would be better if the Authority focussed on the long run decisions around capital expenditure and location and developed a more conventional pricing regime in which tariffs are posted and customers simply pay for their actual load or generation at these tariffs. We agree.

4. COMPLIANCE WITH SECTION 39(2)

4.1. Requirements for regulatory impact statement

4.1.1. Section 39(2) requires the Authority to prepare a statement of its Code amendment objectives, an evaluation of their costs and benefits, and an evaluation of alternative means of achieving the objectives of the proposed Code amendments.

4.1.2. The principal purpose of these steps is to promote better decision-making.

4.1.3. Chapter 2 of the HoustonKemp 2021 Report provides a summary of how this type of process should be conducted to ensure that the best alternatives are chosen to meet the regulatory change objectives.

4.2. The Authority's previous regulatory impact analysis

4.2.1. Appendix C sets out a summary of the Authority's previous TPM reform analysis between 2012-2020, including its analysis of alternatives and CBA results.

4.2.2. It shows that the focus of the Authority's alternatives evaluation has very much been on the degree to which particular alternatives align with the Authority's *preferred vision of charges*

[15] CEC 2021 Report, page 31

[16] CEC 2021 Report, page 32

based on the net private benefits derived by individual transmission customers from each BB investment.

4.2.3. As an example, in its 2019 Issues Paper, the Authority eliminated four options (the status quo, a simplified staged approach, a deeper connection charge and tilted postage stamp) on the basis that its reform alone would ensure that beneficiaries bore their share of the cost of a new investment while the alternatives would not.

4.2.4. The difficulty with a qualitative assessment of this kind *from a process perspective* is that the outcome can be very arbitrary and turn on a single component rather than present a balanced assessment of all the features of credible alternative means of addressing the identified issues.

4.2.5. In the 2019 and 2020 CBAs, the Authority did not quantitatively assess the main components of the most credible options advanced by submitters to identify the option likely to yield the best benefits overall but instead only assessed selected elements of its reform, the status quo, and an option labelled the Alternative[17].

4.2.6. Our view is that section 39, in the current context, requires more than a summary dismissal of credible reform options based on a single subjective assessment and a quantitative assessment of only a few elements of the preferred option.

4.2.7. The Authority cannot rely on its prior alternatives assessment for this Code amendment as that analysis was not fit-for-purpose.

a) It was made based on the Authority's *vision* of a BB charge, not the actual charges now proposed. As the preceding sections have explained this TPM does not deliver what the Authority envisaged. It follows that the Authority's assessment needs to be revisited to cover the actual effects of its proposed new charges.

b) In addition, options which would have delivered similar results to the Authority's reform objectives more efficiently, and without the risks of this Code amendment, should have been properly evaluated. They were not.

4.3. The Authority's problematic approach to CBA

4.3.1. It is clear from the Authority's previous analysis of the TPM reform options, that the Authority considers:

a) it is not required to undertake a quantitative assessment of the short listed options but can dismiss alternatives based on its own qualitative assessment;

b) the purpose of CBA is not to assist in selecting the option that will generate the largest net benefits but to quantify the benefits of the preferred option;

c) it does not need to separately evaluate the main components of the proposed reform;

d) the CBA is not pivotal to its reform but only part of a "*much broader range of factors*" taken into consideration; and

e) it can reform the Code based on "*net benefits to consumers*" and does not need to take into account any offsetting costs to generators.

4.3.2. Trustpower disagrees with the Authority on each of these matters.

4.3.3. This not only undermines the credibility of the present reform but also is a very problematic precedent.

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[17] This was said to be equivalent to a modified RCPD charge with a retained HVDC charge but in practice the charge was modelled in the same manner as the BB charge (except for the inclusion of the HVDC assets)

4.4. CBA supporting this Code amendment

4.4.1. The new CBA for this Code amendment suggests that the Authority is concerned about some of its prior work.

4.4.2. Although the overall net benefit estimates are similar to those estimated in the 2020 CBA, the components that underpin this result are very different, as indicated in table 1.1 of the HoustonKemp's latest critique (which is reproduced below).

Category of benefits	Revised CBA (10 June 2020) Median	New CBA (8 October 2021) Probability weighted mean
Net change in consumer welfare	1,131	1,098
Gross change in consumer welfare	*715*	*2,303*
Transfers from consumers to generators	*416*	*-1,205*
Less efficient battery investment	51	55
Transmission benefits brought forward	95	243
Transmission costs brought forward	-35	-281
More efficient investment	40	106
Increased scrutiny of investment	49	47
Increased investor certainty	31	11
Net benefit	**1,335**	**1,253**

4.4.3. HoustonKemp's 2021 Report (provided as Appendix D) explains these changes.

4.4.4. Despite the similarities of the headline result, the changes in the 2021 CBA go beyond updating input assumptions and include major changes to the method by which benefits have been assessed. This is a substantially different CBA.

4.4.5. Some of these changes are improvements, others are troubling as they appear to continue previous erroneous approaches or introduce new errors to the Authority's analysis.

4.4.6. Our comments on the core changes follow.

Evaluation of alternatives for simple method overhead cost allocation

4.4.7. Chapter 2 of the HoustonKemp 2021 Report discuss the CBA results for the alternative cost allocations for the simple method and the allocation of overhead costs.

4.4.8. The net benefits of alternative options are materially higher than the Authority's proposed option – by $1,124m in the case of the '75/25' scenario and by $321m in the case of the 'overhead opex in residual charge' scenario.

4.4.9. HoustonKemp comment:[18]

> *"These net benefits do not appear to be negligible. When considered against the Authority's determination to proceed with its TPM guidelines on the basis of net benefits of $1,335 million in its Revised CBA, or the much smaller net benefits of $213 million in the Oakley Greenwood CBA, it appears surprising that the Authority does not consider the prospect of $1,124 million of*

[18] HoustonKemp 2021 Report, page 7

additional present value net benefits to be 'strong evidence' supporting the adoption of the '75/25' assumptions."

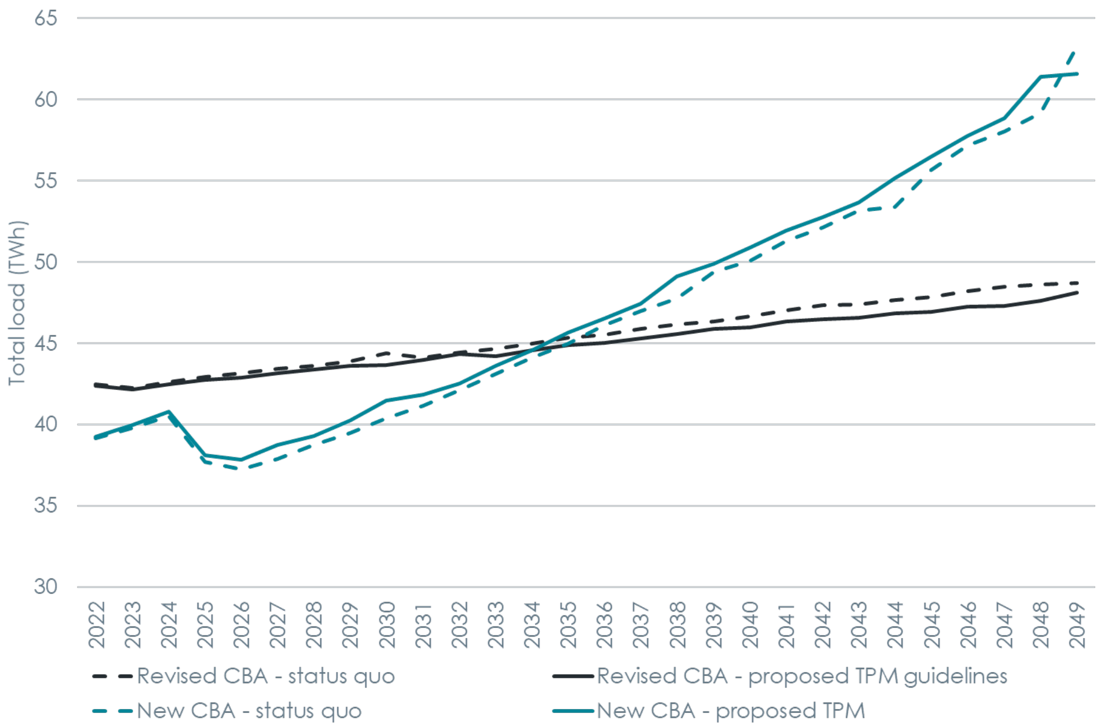
4.4.10. Our experts also note:[19]

> *"The purpose of CBA is to lend rigour to decision-making by placing a framework around it that requires the decision-maker to make decisions on the basis of evidence. That is, the CBA should be the framework for the Authority's decision-making process, and should incorporate (either quantitatively or qualitatively) the factors that the Authority considers relevant to its objective. The relegation of the CBA to just one of several factors to which the Authority may have regard does not appear to be consistent with this standard of evidence-based decision-making.*
>
> *Finally, we agree with the Authority that a lack of clear evidence supporting an option should weigh against the selection of that option. However, the lack of evidence about the effects of the 75/25 option is not unique to that option – the New CBA contains many strong assumptions about how the Authority's proposed TPM will change market outcomes for which there are little or no evidence. The 2019 and Revised CBAs also contained many such assumptions of the proposed TPM guidelines. The standard of evidence that the Authority requires in order to select the 75/25 option as its preferred implementation of the TPM appears wholly inconsistent with its current and previous approaches to CBA."*

Demand growth

4.4.11. Chapter 3 of the HoustonKemp 2021 Report describes how the Authority is now assuming much stronger demand growth relative to the CBA on which it based its decision to adopt the TPM Guidelines.

4.4.12. The difference is substantial, as is shown in the graph below from the HoustonKemp 2021 Report.



[19] HoustonKemp 2021 Report, page 8

4.4.13. This leads to a requirement for an additional 68 generators (70 under the current TPM) to meet this demand (with 13 of these required in 2049 under the status quo).

4.4.14. The Authority finds that consumers will pay less overall for electricity as a result of its proposed TPM. For example, in its central scenario with baseline assumptions, the Authority estimates that average total electricity prices will reduce by 17.1 per cent as a result of the proposed TPM. As a weighted average across sensitivities in the central scenario, average total electricity prices reduce by 11.8 per cent.

4.4.15. At the same time, the Authority's modelling finds that generators tend to receive higher prices as a result of its proposed TPM. The Authority's modelling indicates that average wholesale prices increase by 3.7 per cent in the central scenario with baseline assumptions, and by 10.9 per cent on a weighted average basis across the central scenario.

4.4.16. HoustonKemp advise that:[20]

> *"The changes in prices that the Authority estimates are substantial given the relative contribution of transmission charges to electricity prices in New Zealand and are not highlighted in the Authority's consultation paper or in its technical paper. "*

4.4.17. As noted previously a great deal rides on the Authority's analysis of price impacts being accurate.

Load response to new TPM

4.4.18. The Authority has adopted a new approach to modelling customer response. This is explained in Chapter 4 of the HoustonKemp 2021 Report.

4.4.19. In essence the Authority now treats: BB charges for existing assets as fixed; BB charges for new assets as fixed post-commissioning; and Residual charges as partially fixed.

4.4.20. The Authority states that these changes to its modelling of customer response are "*necessary for distinguishing the different effects of BBCs and residual charges and thus to account for trade-offs embedded in the proposed TPM*".[21]

4.4.21. However, this does not explain why the Authority's modelling approach has changed. The TPM Guidelines analysed in the 2020 CBA contained the same requirements as the proposed TPM in respect of the requirement for BB charges to be fixed and the requirement for Residual charges to be charged based on historical AMD.

4.4.22. The magnitude of these changes is substantial: the issue then becomes whether this magnitude of change is plausible?

4.4.23. The effect of these changes is that in the 2021 CBA, load customers perceive the proposed TPM as giving rise to lower electricity prices and respond with higher consumption, which in turn raises wholesale prices for generators.

4.4.24. The Authority's CBA is based on a view that load customers will face substantial increases in charges but not respond to these if they are substantially fixed.

[20] HoustonKemp 2021 Report, page 16

[21] Electricity Authority, *Proposed TPM 2021: CBA approach, methods and assumptions*, Technical paper, 19 October 2021, paras 2.12-2.14.

4.4.25. HoustonKemp note that BB charges are not in fact fixed in the long run due to the range of adjustment provisions in the TPM[22]:

> *"We expect that these clauses would operate to ensure that benefit-based charges adjust so as to continue to reflect estimated benefits from use of the grid, and therefore (to some extent) to reflect changes in usage over time. Indeed, we expect that this is the purpose of these adjustment mechanisms, without which the proposed charges would be unlikely to have any durability.*
>
> *Over the long run, therefore, there are good grounds to suppose that benefit-based charges would adjust to reflect sustained changes in consumption and associated benefits and that load customers would be capable of responding to the expectation of such changes. These observations are not consistent with the Authority's approach of treating benefit-based charges as wholly fixed in the long run."*

4.4.26. HoustonKemp comment[23]:

> *"Due to its material implications, this changed assumption by itself largely explains why the Authority estimates positive net benefits in its CBA. However, the changing assumptions also gives rise to concerns because:*
>
> - *there appear to be no changed circumstances that could explain why the Authority has changed these assumptions; and*
> - *the reliability of the changed assumptions is open to significant question since there is little reason to expect that benefit-based charges will remain fixed in the long run as the Authority assumes."*

Approach to modelling consumer surplus

4.4.27. The Authority has also changed its approach to estimating consumer surplus and producer surplus.

4.4.28. Some of these changes appear to be driven by a desire to correct previous errors.

4.4.29. The direction of this change is positive, but our experts remain concerned that the Authority's new approach to estimating the change in consumer surplus leaves this number largely reliant on a parameter (the maximum price at which load would not consume any electricity) that the Authority selects without a solid empirical basis.

4.4.30. Problematically this is the most important component of the Authority's estimate of net benefits for its proposed TPM and as the Authority admits its estimates of consumer surplus are extremely sensitive to these assumptions about the shape of the demand curve.

Estimate of producer surplus

4.4.31. The Authority estimates producer surplus as a cross check to ensure its proposals "*would not undermine efficient market dynamics*".

4.4.32. As previously submitted, we think the Authority should be making Code changes on the basis of total surplus, not consumer surplus.

4.4.33. In the 2020 CBA the Authority made an error that caused it to estimate an increase in producer surplus, when in fact producer surplus was lower under its proposed TPM guidelines.

4.4.34. It has now changed its approach. Its new calculations provide a substantial producer surplus - $5.6 billion- but is difficult to reconcile this surplus with the change in generation costs (an increase of $435 million in present value terms).

[22] HoustonKemp 2021 Report, page 20

[23] HoustonKemp 2021 Report, page 3-4

4.4.35. As HoustonKemp observe it is difficult to understand how this level of additional expenditure can result in 'revenue increases far in excess of this, and therefore substantial overall increases in profitability and surplus.' HoustonKemp further notes that one the Authority's sensitivities finds that producer surplus will increase by $44 billion

Omitted costs

4.4.36. HoustonKemp have advised that the Authority continues to incorrectly exclude from its estimates of net benefits the increased costs that higher peak demand under its proposed TPM would impose on the generation and distribution sectors of the electricity industry.

4.4.37. These amount to a further $435 million and $211 million of costs that the Authority has not included in its assessment of costs and benefits.

4.4.38. Once again, the 2021 CBA has not fully modelled the proposal leaving important concerns that affect its reliability. A further review is required.

Wealth transfers

4.4.39. Section 7 of the HoustonKemp 2021 Report addresses continued concerns around wealth transfers being a feature of the Authority's CBA's:[24]

> *"… , the fact that consumers are paying lower variable prices and generators are receiving higher variable prices is not itself a benefit if these changes are merely funding new fixed charges imposed on consumers and generators (which are not shown in the figure). That is, a significant part of an increase in the blue shaded area shown in figure 7.1 arises because the overall size of the grey rectangle collected by Transpower in variable charges has reduced (since some variable charges have been replaced with fixed charges). The Authority's technical paper leaves unclear how it has addressed these issues, since it does not indicate that it has deducted these fixed charges from consumer surplus under its proposed TPM."*

4.4.40. This lack of transparency is disappointing.

5. CONCLUDING REMARKS

5.1.1. Trustpower is adversely affected by this reform as our generation plant was built to assist distributors to minimise their peak demand on the transmission system. Consequently, the removal of the variable RCPD charge has a financial impact on our business.

5.1.2. For this reason, we have been careful to support our submissions on these reforms with the views of independent experts with substantial expertise in the area. Those experts have repeatedly told us that New Zealand does not need radical tariff reform of the kind proposed and that the Authority is trying to achieve too much.

5.1.3. In particular the BB charge and Residual charge are going to front load costs on existing customers in a somewhat arbitrary fashion which will only reflect their private benefits by chance.

5.1.4. This creates a risk of failure on all fronts: decarbonisation, energy affordability and energy security.

5.1.5. In this submission we have tried to explain the sources of this risk by stepping through the experiences of different transmission customers. The CEC report highlights the complexity of the new regime for those who simply what to know what their transmission costs will be before they make their investment.

[24] HoustonKemp 2021 Report, page 33

5.1.6. It also notes the risks associated with the Authority's priority of geographical equity over generational equity is that we will end up with a future grid of uneconomically small lines and upgrades as transmission customers seek to reduce variable and uncertain charges and delay investment until there is as much clarity as possible.

5.1.7. This is not the Government or Climate Change Commission's vision for the future.

5.1.8. Our fear for existing and future consumers is that the adoption of this Code amendment will result in a range of upfront costs and the loss of low-cost demand response, for no positive benefits as the TPM will need to be amended within the decade if the Government's objectives for the sector are to be realised.

For any questions relating to the material in this submission, please contact Fiona Wiseman, Senior Regulatory Advisor on 0275499330.

Regards,

Peter Calderwood
General Manager, Strategy and Growth

Appendix A: Trustpower's responses to TPM consultation questions

Question	Response
Chapter 2: A new TPM	
1. Do you have any comments on the content of this chapter?	1.1 Trustpower is concerned that the 2020 Decision paper (and its predecessor papers) provided a series of qualitative propositions that were not properly assessed for materiality, counterbalancing factors, or tested against actual evidence. 1.2 This includes the propositions that: • There is significant (unmanageable) volatility of prices under RCPD charge; • The RCPD charge only results in inefficient cost-shifting and never engenders efficient investment or efficient operation to avoid peaks; • The signals provided by nodal prices are adequate for future transmission investment including investments to meet reliability standards; • The ssignals provided by connection charges and nodal prices are on the other hand inadequate and require supplementation to ensure there is no inefficient location decisions made by load and generation; • Without TPM reform gold plated investments will be approved by the Commerce Commission due to the mis-incentives provided by postage stamp pricing; • The HVDC charge (and not other factors) is deterring South Island investment to a degree that justifies the immediate reallocation of this charge to those who have been assessed as HVDC beneficiaries in the 2014-18 time period; • Transmission customers will accept the proposed assessments of benefits of individual transmission assets (and all adjustments, reassignments and reallocations of this charge and the other charges) as reasonable and not dispute or challenge them; and • No efficient transmission investment will be delayed as a result of this proposal.

	1.3 If these problem statements were assessed for materiality, counterbalancing factors and actual evidence it is likely a different solution would have been preferred. 1.4 An empirical assessment of this nature would have "opened the door" to more moderate, and more tractable, reform.
Chapter 3: Grid Asset classification	
2. Do you agree with the proposed approach to treat connection assets as interconnection assets for a limited time if the assets will ultimately be interconnection assets when fully commissioned?	2.1 Trustpower agrees with the proposal to allow connection assets to be treated as interconnection assets for a limited time if the assets will ultimately be interconnection assets when fully commissioned (i.e. adoption of Additional component A). 2.2 Trustpower agrees with the new provisions which will ensure that in the future connection assets cannot be converted into interconnection assets by a customer creating a loop in the grid (i.e. adoption of Additional component B).
3. Do you agree with the proposed reclassification power? Should there be any further conditions on Transpower's use of this discretion?	3.1 Trustpower agrees that Transpower should have the ability to reclassify interconnection assets as connection assets if the substance principally proved connection services. 3.2 This should apply to new configurations.
4. Do you have any other feedback on Grid Asset Classification in the proposed TPM?	4.1 No.
Chapter 4: Connection charges	
5. Do you agree that the proposed TPM should specify that connection asset replacement values be regularly updated to promote cost-reflective charges and certainty?	5.1 Trustpower agrees that Transpower should update its grid asset replacement costs building blocks every five years. This will ensure that assets are appropriately valued and the relativities between assets are accurate before apportionment.

6. Do you have any comment on the proposed approaches to address first mover disadvantage issues, including on: • the proposed FAC mechanism for Type 1 FMD • the alternative option of an upper limit on application of the benefit-based approach for Type 2 FMD • the approach to applying 'above-limit costs' under this alternative option?	6.1 Trustpower agrees that the First Mover Disadvantage will become material in the context of the energy transition. This has not been a significant problem with connection assets to date as they have generally been customer specific. However, we expect it will become an increasing issue with increased electrification and note the Concept Consulting report anticipates as much as $500m of grid connection investment for generation and $300m for process heat electrification. 6.2 Trustpower supports the inclusion of a funded asset component into the connection charge to collect a financial contribution from subsequent connecting parties towards the capital cost of the connection investment that was funded by a First Mover customer. 6.3 We do not think that competition concerns arising from the prospect that a First Mover customer (with a right of rebate in relation to costs incurred) would then have an advantage over subsequent entrants in relation to subsequent connections are significant. 6.4 Trustpower does not agree with the proposal to introduce a further type of BB charge whereby the costs of anticipatory capacity are allocated to: a. regional load for a generation connection asset; or b. regional generation for a load connection asset using the simple method (which we understand will be based on the typical pattern of electricity flow on the grid). 6.5 This additional BB-type charge could create a significant burden on connection parties in some regions who are determined to be the parties which have to pay for this anticipatory capacity by virtue of their location. This issue is exacerbated by the Guideline requirements that connection charges cannot be "backloaded". 6.6 The Authority's proposal is not consistent with the outcomes which would occur in workably competitive markets and the Authority's aspiration that charges should be allocated in accordance with net private benefits. 6.7 If the Authority does proceed down this path (which we do not support) we recommend that it introduce a limit on the maximum amount of anticipatory capacity which can be reassigned to any transmission customer at no more than 10% of that transmission customer's connection charges. 6.8 However, our preference is to socialise the costs of the anticipatory capacity across all customers.

	6.9 We think that in analysing this issue the Authority has overstated the prospect that load and generation customers will strategically withhold information about their intentions when new connection assets are being designed and built by Transpower. It is far more likely that the subsequent movers will not have decided on their investment priorities at the time of any upgrade.
7. Do you have any other feedback on the proposed TPM in relation to connection charges?	7.1 No.
Chapter 5: Benefit-based charges: allocation	
8. Do you have any comment on the proposed standard and simple benefit-based allocation methods?	8.1 The rationale for introducing BB charging is that it is said to improve investment efficiency and durability. Underpinning this proposition is an assumption that charges under the new methodology will be allocated according to forecast net private benefits. However, no attempt has been made to model the future revenue streams of transmission customers with and without the assets in question. This is the only way we know to assess private benefits. 8.2 Instead, four different BB charges use different combinations of regional allocations, historic benefits or usage, geographical averaging, and administrative determinations to assess "*approximate benefits*". There is absolutely no evidence that the patchwork of allocations which result from these methodologies will provide any clear price signals for locational decisions and grid scrutiny. 8.3 The CEC 2021 Report and our cover letter comment on the discriminatory outcomes which will occur under the proposed amendment. The collective result will be uncertainty, increased cost and a reduction of incentives to invest. 8.4 To address these issues the Authority needs to simplify its proposal in the manner suggested by CEC or start again.
9. Do you have any comment or additional evidence on the proposed weighting of benefits between load and generation customers under the simple method, or	9.1 Trustpower does not support the proposed 50/50 split. We recommend that a 75/25 split is adopted now and reviewed in 5 years' time.

with respect to the proposed review of the allocation?	9.2 We struggle to reconcile the Authority's willingness to impose an arbitrary allocation of costs under the simple method with its views that overhead opex should potentially not be allocated to generation because of the adverse effects of the additional cost "*postponing generation, reducing competition and leading to higher wholesale electricity prices over time*"[1] 9.3 We asked for advice on this issue from CEC. The CEC 2021 Report notes that, contrary to earlier assertions that BB charging would identify net private benefits of each BB investment[2]: *"…Transpower has proposed – and the EA has accepted – BBC methods that are generally price agnostic. They either avoid forecasting price entirely or they make simple, hard-coded assumptions about how prices would move if the BBI is introduced.* 9.4 This leads to different types of sharing methods[3]: *"In the simple method, there is a simple "50:50" kind of assumption: that flows from generators and flows to loads have equal implied value [this does not, as I understand it, necessarily imply that the outcome of the BBC method will be an exact 50:50 sharing of the BBI costs]. Transpower has chosen this approach on the basis that there is no obvious, prima facie, reason to favour one sector over the other in the algorithm. The EA has accepted this, subject to a future review of this assumption, although whether and how this review will put the question to rest is unclear.* *The standard method does model price outcomes, but the Clutha case study [written by Transpower and published by the EA in its pack of papers for this consultation] suggests that this will be done using hard-coded assumptions which reflect a predisposition on what the shares should be. For example, Transpower's Clutha method assumes that prices will move an equal amount – in opposite directions – upstream and downstream of congestion that the BBI is designed to relieve, thus giving equal $/MWh benefits to each sector [$ benefits between the sectors will still differ, of course, if the MWh are different]."* 9.5 CEC comment that[4]: *"The problem is that these assumptions have never been properly ventilated and discussed – in the way in which, say, the RC sharing factor was. Despite the complexity of the TPM guidelines, this key decision has been left in the hands of Transpower: either in the TPM itself or, for the standard BBC method, in the assumptions that Transpower decides to make for modelling a particular BBI."*

[1] Consultation paper para 6.11

[2] CEC 2021 Report, page 23

[3] CEC 2021 Report, page 24

[4] CEC 2021 Report, page 24

	9.6 This uncertainty and lack of transparency around something as fundamental as the sectoral sharing makes the exacerbates the difficulties that generator and load customers will face in forecasting BB charges on future BB investments. 9.7 Refer to our cover note for further details of our views on this matter.
10. Chapter 6: Benefit- based charges: covered costs	
11. Do you have any comment on the proposed approach to covered costs, including on: • whether overhead opex should be recovered through the BBC or residual charge, and any evidence to support your view? • the recovery of opex on fully depreciated assets through the residual charge?	11.1 If overhead opex is reasonably attributable to a BBI investment then it should be part of the costs of that investment. 11.2 The residual charge should cover those costs which are not readily attributable including opex on fully depreciated assets.
Chapter 7: Residual charges	
12. Do you have any comment on how the proposed TPM implements the residual charge provided for in the Guidelines?	12.1 We do not agree with the Authority's policy decision to gross up the demand of load by adding back concurrent generation as it does not reflect the benefit provided by distributed generation of reducing the need for future transmission investment and discriminates between local generation and demand side management.
13. Do you agree with the application of the residual charge to generation with embedded load, or can you suggest a better way to mitigate charge avoidance	13.1 No comment.

incentives and risk of an uneven playing field?	
14. Do you have any comment on the proposed approach to application of the residual charge to battery storage to avoid double-counting of load?	14.1 This issue has arisen due to the inflexible and restrictive nature of the TPM Guidelines. Our views on this matter have been well documented during Transpower's development process.
Chapter 8: Adjustments	
15. Do you agree with or have any other feedback on the proposed provisions for adjusting transmission charges? The Authority welcomes feedback on any aspect discussed or proposed in this chapter, including whether: • the proposed TPM should provide more detail on the method for determining new entrants' benefits • the charges for a new entrant should be the same as an equivalent incumbent each year (as in the proposed TPM), on a whole-of-life basis as in the Guidelines • the proposed thresholds for 'large' and 'substantial sustained' change in grid use are appropriate • the connection of a distributor to a new (and additional) GXP and the upgrading of a transformer at a distributor's GXP should be adjustment events	15.1 These proposals are designed to close off loopholes and anomalies but in so doing seem likely to open up new loopholes. The end result is likely to be a TPM riddled with discrimination which is antithetical to competition and the efficient operation of the industry. 15.2 A complete rethink is required, as suggested by CEC.

• the plant disconnection provision should be extended to plant de-rating • the relevant provision should be further extended to cover a substantial sustained decrease in grid use not related to a plant disconnection or de-rating • the residual charge for a new entrant and an expanding customer should adjust with a lag and a gradual ramp-up, as proposed • the proposed 'related entity' provisions deal appropriately with avoidance concerns, and whether there is a case for a broader or more general 'related entity' provision to deal with other, potentially unforeseen, avoidance opportunities?	
Chapter 9: Prudent discounts	
16. Do you have any comments on the proposed PDP provisions? The Authority welcomes comment on any aspect of the proposal, including whether: • Transpower should have to prepare a PD practice manual, and if so when, and should it be binding on Transpower	16.1 Trustpower supports the continuation of the current prudent discount provisions and the new rules around the process for seeking and approving such discounts. 16.2 Trustpower does not support the adoption of a prudent discount policy which applies when bypass is not physically or commercially feasible. The proposed standalone prudent discount is simply a discretionary discount which will be available to some customers but not others depending on what scenarios are assumed to apply when assessing stand -alone costs of hypothetical investments. 16.3 If this discount is to be retained, we think it should be sparingly used (for equity reasons).

• 15 years should be the default maximum period with a longer term possible on proof • prudent discounts should be funded via the residual charge and as appropriate the benefit-based charge • customers should be able to terminate a prudent discount agreement before the end date of the agreement?	16.4 We note that the TPM guidelines require Transpower to be satisfied that the standalone cost approximates the cost of supplying transmission services that are of equivalent value to the customer, including in terms of access to energy, quality of energy supplied, reliability and security of supply. 16.5 These factors are not determined by transmission assets alone but also depend upon the generation assets that are made available by means of those transmission assets. To our mind this suggests a condition of the discount should be that the hypothetical investment must connect enough generation assets so as to be capable of providing an electricity supply that is of equivalent value to the supply that the applicant currently receives through the interconnected grid. 16.6 In terms of the mechanics, we support the development and publication of a prudent discount manual setting out the assumptions and methodologies Transpower proposes to use in assessing prudent discount applications; and any other material transmission customers would find helpful to enable them to assess whether or not their particular circumstances warrant an application. This can be updated in the light of prior applications to the benefit of all stakeholders. 16.7 We agree that applications should be accompanied by an expert report by an independent and suitably qualified verifier(s). We note that prudent discount applications could range from simple technical by-pass options to more complex assessments of efficient standalone costs and determination of the nature of the services received by transmission customers (including in terms of access to energy, quality of energy supplied, and reliability and security of supply). 16.8 The nature and scope of the verification required should be proportionate to the scale, materiality and complexity of each application. It may not be necessary for every element of the application to be verified, with some matters potentially being more appropriately subject to director certification or audit. 16.9 Given that the purpose of the residual charge is to achieve the non-distortionary recovery of residual costs, we consider that the recovery of prudent discounts is most appropriately achieved through residual charges.
Chapter 10: Transitional congestion charge	
17. Do you have any feedback on the proposal not to include a TCC in the proposed TPM, for the reason that	17.1 The TPM Guidelines only permit a very narrow form of congestion charge. Transpower has decided that it cannot justify the development costs of a charge within that narrow remit afforded. A similar conclusion is likely to be reached in future occasions of supply/demand pressure.

widespread risk of congestion from removing the RCPD charge is unlikely and that, if necessary, the grid owner and system operator have effective tools to manage the power system quickly and efficiently? If not, how should a TCC be designed to be consistent with the Guidelines? Under what situations should it be applied and how should its size and allocation be determined?	17.2 As we and many other submitters have noted this is a ludicrous outcome. A staged removal of the RCPD charge would give been a low cost way to manage record peak demands through the next decade of energy transition. 17.3 As it stands there is a non-trivial risk the Authority's proposal is likely to lead to price spikes and outages. 17.4 Why take that risk? 17.5 Our detailed views on this matter were outlined during Transpower's consultation on the development of a TCC and we urge the Authority to consider these further.
Chapter 11: kvar charge	
18. Do you have any comment on the proposal not to include a kVar charge in the proposed TPM?	18.1 We are happy to accept Transpower's advice that a kVar charge would add complexity and cost which is unlikely to be offset by material efficiency or reliability benefits.
Chapter 12: Indicative prices	
19. Do you have any comments on indicative pricing or the application of the transitional cap?	19.1 The Authority's impact assessment focuses on transmission customers including industrial load directly connected to the grid. There are a number of large load customers who are connected to distribution networks who will face significant rate shock as a result of this proposal (as their connection arrangements pass on the transmission charges associated with their presence on the distribution network). It would have been better if price increases were phased in for these customers. 19.2 Looking forward the complexity of the proposed TPM means it is going to be very difficult to forecast future transmission charges beyond the next year or so. We consider that the Authority should give further thought as to how the industry can efficiently access indicative charges for the medium and longer terms.
Chapter 13: Other provisions of the TPM	

20. Do you have any comment on or suggestions for the preliminary provisions cl1-18?	20.1 No.
Chapter 14: Regulatory statement	
21. Do you have any comments on the regulatory statement, or the assessment of wider factors?	21.1 For the reasons stated in the cover letter, Trustpower does not consider the Authority has complied with section 39(2) of the Act. It cannot rely on prior assessments of alternatives as those assessments were not fit for purpose.
Chapter 15: Next steps	
22. Do you agree that 1 April 2023 is an appropriate commencement date for the proposed TPM?	22.1 We do not support the 1 April 2023 start date as to our mind this proposal has yet to be fully justified. 22.2 We agree with the sentiments of PowerCo in its 2019 submission that the TPM should start when it is ready. 22.3 PowerCo said[5]: *"It would have been difficult to predict a timeline of the Authority's TPM development (and hold the Authority to it). We should learn from that experience and apply a pragmatic approach to Transpower's implementation process. It'll take the time it takes, and it's worth taking the time to get it right."*
23. Do you agree with the proposed transitional measure for any standard method investments for which allocation is not completed?	23.1 Yes. It makes sense to provide for investments which have been made during the development of this TPM
Appendix C: Proposed TPM	

[5] https://www.ea.govt.nz/assets/dms-assets/25/25749Powerco-Limited-TPM-submission-2019.pdf, page 3.

24. Do you have any feedback that would improve the drafting of the proposed TPM?	24.1 We have not reviewed the drafting of the TPM.
Appendix D: Cost benefit analysis	
25. Do you have any comment on the cost benefit analysis?	25.1 Please refer to our cover letter and the accompanying expert report.
Other	
26. Is there anything else in relation to the proposed Code amendment that you wish to comment on?	26.1 Trustpower does not consider the TPM will promote competition, reliability or the efficient operation of the industry for the long-term interests of consumers. Our reasons are set out in prior submissions, and in the cover letter and expert reports which accompany this submission.
27. Do you have any other feedback on any other aspect of the proposed TPM?	27.1 We would be grateful for clarification from the Authority about whether it thinks future changes to the TPM are Code amendments which need to comply with section 39(2) or that section 39(2) only applies to the initial TPM?

Review of the Electricity Authority’s latest TPM

Creative Energy Consulting Pty Ltd

December 2021

Executive Summary

Introduction

Over the course of its development, discussions around the new Transmission Pricing Methodology (TPM) have progressed from conceptual positions around the role and design of transmission pricing, to the practical issues of how to implement these concepts. What has perhaps been lost sight of are the (transmission) customers and how they will respond to the prices and signals provided by the TPM. Because, at the end of the day, that is *all* that matters. It is where the "rubber hits the road".

This might seem an odd point, because the early conceptual discussions were all about this customer perspective. But what matters is not those concepts, *per se*, but the implementation of them. Indeed, a customer may be uninterested or even unaware of the concepts behind the TPM. Rather, they will have to understand what the TPM means for them: for their investments and operations. Assuming that customers are rational, profit-maximising entities, they will take account of transmission charging impacts on all of their decisions - at least where impacts are likely to be material. For each decision, they will have to ask the question: if I decide to take this action, by how much will my transmission charges change?

Under a conventional transmission pricing regime, where there is simply a schedule of posted tariffs which apply to customer consumption or generation, answering this question is likely to be straightforward. Indeed, the posted tariff is designed to *immediately* answer that question, at least for short-term, one-off actions; for actions with a sustained impact – an investment or disinvestment – projections of *future* tariffs will also be needed

However, under the proposed TPM, things are not so straightforward. Some charges are fixed, and so impervious to customer actions. Others are variable, but not in simple or obvious ways. To make things even more complicated, fixed charges can become variable depending upon the nature or circumstances of the action taken.

Certainly, there is no simple tariff schedule for the customer to refer to.

This report aims to take the hypothetical customer by the hand and walk them through the TPM; to help them understand the impacts of different decisions under different situations. The answers are often surprising. The TPM that the Electricity Authority (EA) has actually delivered may, from this perspective, be rather different to what the EA *thought* it delivered.

Existing Customer

The first situation to be considered is that of an existing load customer. The basic question that the customer wishes to answer is: "if I consume an additional 1kWh of load in a particular trading period, how much will my transmission charges increase as a result?"

This question - and others like it applying to other business inputs - are fundamental to how businesses plan and operate. Every electricity purchasing manager will be expected to have the answer at their fingertips. It is a different perspective to the EA's and Transpower's. But it is the only one that matters to electricity-consuming businesses.

A load customer pays the residual charge (RC) and various benefits-based charges (BBCs), each of which is attributable to a benefit-based investment (BBI): a historical or future transmission project to which the BBC methodology applies. It will pay various other charges, such as connection charges, but these are unlikely to be affected by small changes in consumption and so are ignored.

For small changes in consumption by an existing customer, transmission charges may be fixed or variable: BBCs relating to *historical* BBIs are fixed, whereas BBCs relating to *future* BBIs, within the relevant time window, are variable, as is the RC. For each of the variable charges, payment lags consumption: service provision is, in effect, on a "buy-now-pay-later" basis.

For RC it is simply the case of lagging payment by 4-8 years, which has the present value effect of reducing the transmission price by around 50%. Transpower does not suffer from this payment delay, by virtue of being permitted to, in effect, double-charge existing customers for their consumption over the years immediately prior to the TPM change: once under the old TPM regime and again, on a delayed payment basis, through the RC.

For new BBIs, the payment timing is less clear but, roughly speaking, the BBC for a BBI is based on consumption for the few years prior to the time the BBI is committed. This timing is reminiscent of an LRMC-style tariff, where tariffs rise in advance of the investment and then fall to zero once the investment occurs. There is something to be said for this LRMC approach, but it is surprising that the EA has implemented it by proxy, given that it strongly rejected this LRMC alternative when it was put forward during the development of the TPM.

Unlike a conventional LRMC tariff, the BBC methodology – and even the BBIs on which this is applied – are likely to remain uncertain to the customer at the time of their consumption: ie several years in advance of the BBI commitment. This uncertainty will add substantial risk to customer decision-making and associated profitability.

In the light of the TPM's similarity to these corresponding conventional approaches, it is remiss of the EA not to have properly considered these simpler alternatives. It could have saved itself a lot of trouble – including around the design of the various reopeners discussed below – if it had done so.

New Load Customer

The TPM's impacts on a new load customer differ from those of an existing customer in three main ways. Firstly, it is likely to trigger various reopener provisions in the TPM, either because the customer is entirely new and/or there is an associated large step-change increase in load. Secondly, the customer potentially has a choice of location, including whether to be embedded; clearly this choice does not arise for incremental consumption by an existing customer.

Finally, whilst an existing customer is notionally deciding on a one-off increase in consumption within a single trading period, a new customer is making an entry decision which will commit it to some future consumption for the life of its new plant: so, potentially for decades.

A new load customer essentially pays a locational, variable tariff consisting of the RC, historical BBIs and future BBIs. Whilst these charges are only fully-variable in terms of their long-term decision to enter (short-term decisions, discussed in the previous chapter, are a mixture of fixed and variable), it is this kind of decision for which transmission tariffs have the biggest impact.

The EA could have provided substantially the same long-term incentives simply by designing a Tilted Postage Stamp (TPS) style variable tariff with equivalent prices. The TPS could be designed to reflect only historical BBIs – with remaining existing assets covered by the residual charge, mimicking the TPM. Alternatively, the use of the simple BBC method would allow *all* assets to be treated as historical BBIs, and so charged for on a locational, rather than postage-stamp basis. This would have advantages in terms of simplicity and certainty, and simply brings forward the outcome that we will reach several decades into the future when non-BBI assets are finally retired or replaced. Again, given that the EA rejected the TPS during TPM development, it might be surprised to find that its preferred TPM gives outcomes quite similar to this, but with more complexity and a much longer transition period.

Instead of implementing a conventional, fully-variable tariff, the EA has chosen to make tariffs quasi-fixed by relying on TP-estimated metrics for new customers: AMD for RC, and coincident and average demand for BBCs on historical BBIs. It is not clear how Transpower would calculate these estimates, or what risks are created for new load customers as a result.

New Generator Customer

Unlike the load customer, a new generator is likely to be a "big fish in a small pond", whose entry is liable to trigger – or substantially change the timing of – some new BBIs for which it bears a substantial portion of the cost. It also may share its connection with existing or future generators.

Inherent in all transmission planning decisions is how much capacity should be built in excess of immediate requirements, to economically cater for future growth. Correspondingly, a key consideration in transmission *pricing* is who should pay for the cost of this excess capacity, and who should bear the stranding risk that the anticipated growth never eventuates. The EA has decided that *existing* (at the time of the investment decision) customers should be liable for both. Whilst future customers will shoulder some of the burden, if and when they enter, their contribution will be disproportionately small, due to the impacts of discounting and depreciation. Since it is future customers – not current customers

– who primarily benefit from the excess capacity, this runs counter to the EA's beneficiary-pays philosophy, and exacerbates the generational equity problem of current customers paying for assets that only futures customers benefit from.

The TPM approach creates a first-mover problem – which the EA recognises but has not been able to satisfactorily address – where an entering generator triggers new investment (whether for connection or for interconnection) incorporating excess capacity for which it is required to pay the lion's share until later entrants arrive. Of course, it cannot know whether these will arrive at all. So moving first is extremely risky, and will result in a crisis of coordination: no project will want to be the one who goes first. This problem could be substantially addressed by providing that load customers generally, rather than first movers, bear the initial costs and stranding risks of the excess capacity, through adjustments to the residual charge

A key question in any transmission pricing policy is how to divide costs between the generation and load sectors. The EA guidelines explicitly answered this question for the RC, but not for BBC, assuming that the latter would simply be an outcome of the BBC modelling in each case. That was always optimistic; the BBC models would need to forecast energy prices – and the impacts that a new BBI has on these - to answer the question, and this was always going to be problematic. Transpower has sensibly proposed – and the EA has accepted – methods which reduce reliance on this impossible task, by introducing hard-coded assumptions into their models which effectively dictate the sharing outcome.

These assumptions, broadly speaking, implement an approach of sharing costs 50:50 between load and generator customers. This has been adopted at the eleventh hour, with limited scrutiny, analysis or consultation; even the EA is uncertain that it is the right approach and has flagged a future review. This represents a major failure of the TPM review process.

Customer Engagement

It has always been the contention of the EA that the BBC approach will encourage customer engagement in the planning process and so lead to better planning outcomes. Now that the TPM has taken clear shape, this argument can be re-examined, from the perspective of our hypothetical customer.

To the extent that customers are large enough to play any significant role in the planning process, we can assume that they will be rationally profit-seeking in their engagement, just as they are when responding to the TPM price signals. In short, they will only engage if the expected financial benefit to them of engaging will exceed the cost of the engagement. Furthermore, in deciding how to engage, they will aim to maximise this benefit.

In the light of the EA's decision to foist the costs and risks of excess capacity onto existing customers, it can now be seen that customers' contribution to this process will be unhelpful: they will simply urge Transpower to minimise the amount of excess capacity created. If Transpower were to take any notice of these representations, it would build a future grid of uneconomically small lines and upgrades. In short, the EA's philosophy requires that Transpower accommodates customer preferences, but good planning requires that it doesn't.

Inevitably tied up with the planning process will be discussions around the design and outcomes of the BBC method used to allocate the costs of the BBI. As a zero-sum game, this process is likely to be extenuated and fractious. It is not clear how the BBC and BBI processes will be inter-linked, but it seems likely that, for major projects at least, any interactions will cause both to be delayed.

The underlying problem is that a key stakeholder is missing from the table: the future customer. A reason we have independent planners and regulators is to act on their behalf in their absence. As we transition to a zero-carbon world, the needs and interests of future customers – whether in the form of new renewable generators or newly "electrified" energy consumers – loom ever larger. In this context, the EA's idea of putting existing customers in the driving seat for transmission planning is unhelpful and misconceived.

Load Exit

A load exit is a logical extension of an existing customer considering reducing load and so bears similarities to that latter situation, in that:

- the load has a chosen location and sunk capital; and
- the load has payment liabilities, due to the "buy now pay later" structure of the RC and BBCs.

The key difference, though, is that the exiting customer has no ongoing commercial relationship with TP, so there is no mechanism through which Transpower can ensure that payments can continue until the liabilities are extinguished. And this causes some problems for the TPM design, in that an exiting customer, unlike a continuing customer, will "buy now" but *not* "pay later".

Since different rules inevitably apply to exiting and continuing customers, the question arises: where do you draw the line? Is the "customer" a load, a plant, a site, a firm, a conglomerate…? Wherever the line is drawn, a customer is then incentivised to shape shift, from one form into another, to cross that line, to change its load reduction into an "exit". In doing so, it can potentially save itself a lot in transmission charges at only a small additional direct cost to its business.

Aware of these boundary effects, the EA has had various attempts at locating this "line in the sand" and continues to propose further variations in its latest consultation paper. But these efforts are like a tax collector attempting to plug loopholes in poorly designed tax legislation; and they are doomed to fail, because the "tax dodgers" are always nimbler and more creative (and better remunerated!) than the tax collectors.

And this is all so unnecessary. By choosing to create this ramshackle, buy-now-pay-later TPM infrastructure, the EA has made a rod for its own back. As discussed in the previous chapters, conventional buy-now-pay-*now* tariff structures can provide similar incentives to the TPM, at least for the *long-term* decisions that really matter. That those simple, equivalent tariffs go by the name "Tilted Postage Stamp" shouldn't discourage the EA from adopting them, even at this late stage.

Conclusions

In developing its TPM, the EA originally set out a stark vision of how it would look: charges would be based on customer benefits from new assets, whilst the cost of sunk assets would be recovered through fixed charges that customers were unable to avoid. But this vision was never something that could be practically implemented in its pure form, because customers will inevitably enter and exit; and fairness and durability require that entering customer pay their fair share of sunk costs, whilst exiting customers cannot continue to be charged. Once exceptions are carved out for such situations, there are immediate boundary questions as to what is a "customer" versus a premises or a large electrical plant, and why it is fair or efficient to treat one differently to the other.

So, over the latter years of the review, as we have moved from conceptual outlines through to a final implementation, the EA has introduced a series of complexities and compromises into the TPM to address these boundary issues. And, as these have added further complexity, they have also remorselessly moved the charging outcomes – as seen by the customer – closer and closer to a conventional transmission pricing regime, in which tariffs are posted and customers simply pay for their actual load or generation at these tariffs. No fixed charges; no baselines; no "buy-now-pay-later". Just a simple "user pays", like for almost every other product, in almost every other market.

With the detailed development of Transpower's modelling of transmission benefits, we can get a foretaste of what this underlying tariff might look like, as we gradually transition from the flat residual charge to the locational benefit-based charges. And it appears that this will be similar to the Tilted Postage Stamp concept which many argued for right at the commencement of this review and which the EA has consistently rejected as inappropriate and inefficient. Superimposed on this, there is a charging component looking similar to a "long run marginal cost" pricing approach; a concept which the EA has also vigorously rejected.

Customer decision-making is ruthlessly prosaic; philosophical and conceptual considerations are ultimately irrelevant. The only question that matters for the customer is: how much will this decision cost me (or save me) in transmission charges? And, when that calculation is undertaken – as this report has described – what the customer will see is effectively a Tilted Postage Stamp tariff, obscured somewhat by the complexities and uncertainties inherent in the asset-by-asset, benefit-based approach.

That, at least, is true for long-run decisions around capital expenditure and choice of location. But these are the decisions where transmission pricing is likely to have the biggest impact on outcomes and on economic efficiency. Even if the TPM's unconventional approach were able to improve the efficiency of short-run decisions (which it won't), the economic gains would be far outweighed by the higher transaction costs and commercial risks created by its complicated new regime.

So perhaps there is a chance to "cut our losses" here. To understand what this underlying tariff looks like and simply to implement *that* in the TPM. Because, if we continue down the current path, it seems inevitable that we will continue to confront – and fruitlessly endeavour to resolve – the contradictions inherent in the EA's TPM vision.

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1 INTRODUCTION

1.1 ENGAGEMENT

Creative Energy Consulting (CEC) has been engaged by Trustpower to review the Electricity Authority's (EA's) consultation paper "Proposed transmission pricing methodology: consultation paper", dated 8th October 2021[1], and also the associated latest transmission pricing methodology[2] (TPM) published at the same time. I, David Smith, am the director of CEC and the author of this paper.

1.2 EXPERIENCE

I have been involved in transmission pricing specifically, and electricity market reform generally, for over thirty years, with projects spanning markets in New Zealand, Australia, the UK, the US and China. Across this diversity of geographically and regulatory characteristics, I have always been guided by two tenets. That transmission pricing is necessarily and appropriately customized to the characteristics of each particular market. And that, nevertheless, there are some generic, fundamental principles of good pricing design that are always relevant and important.

1.3 DISCLAIMER

This report presents the views of myself and my company, CEC, and does not necessarily, and is not intended to, represent the views of Trustpower.

I have endeavoured to understand fully the provisions of the latest TPM and apply these accurately in my analysis. However, given the increasing scope and complexity of the various methodologies and contingencies, it is quite possible that I may have misinterpreted some provisions or missed others: especially those that have changed since the last time I looked at the TPM or its guidelines. I do not expect that any such errors will materially affect my analysis or conclusions.

[1] Which I refer to in this report as "the Consultation Paper".
[2] version 2

1.4 Approach

Over the course of its development, discussions around the TPM have progressed from conceptual positions around the role and design of transmission pricing, to the practical issues of how to implement these concepts. What has perhaps been lost sight of are the customers[3] and how they will respond to the prices and signals provided by the TPM. Because, at the end of the day, that is *all* that matters[4]. It is where the "rubber hits the road".

This might seem an odd point, because the early conceptual discussions were all about this customer perspective. But what matters is not those concepts, *per se*, but the implementation of them. Indeed, a customer may be uninterested or even unaware of the concepts behind the TPM. Rather, they will have to understand what the TPM means for them: for their investments and operations. Assuming that customers are rational, profit-maximising entities[5], they will take account of transmission charging impacts on all of their decisions; at least where impacts are likely to be material. For each decision, they will have to ask the question: if I decide to take this action, by how much will my transmission charges change?

Under a conventional transmission pricing regime, where there is simply a schedule of posted tariffs which apply to customer consumption or generation, answering this question is likely to be straightforward. Indeed, the posted tariff is designed to *immediately* answer that question, at least for short-term, one-off actions; for actions with a sustained impact – an investment or disinvestment – projections of *future* tariffs will also be needed

However, under the proposed TPM, things are not so straightforward. Some charges are fixed, and so impervious to customer actions. Others are variable, but not in simple or obvious ways. To make things even more complicated, fixed charges can become variable depending upon the nature or circumstances of the action taken.

Certainly, there is no simple tariff schedule for the customer to refer to.

This report aims to take the hypothetical customer by the hand and walk them through the TPM; to help them understand the impacts of different decisions under different situations. The answers are often surprising. The TPM that the EA has actually delivered may, from this perspective, be rather different to what the EA *thought* it delivered.

[3] references to customers in this report generally mean transmission customers – parties directly connected to the transmission grid – rather than the conventional meaning of electricity consumers. Sometimes it also means distribution customers, embedded generators and end-users connected to a distribution network which connects to the transmission grid, to the extent they are materially impacted by the TPM design.
[4] acknowledging, of course, that it is important for Transpower to recover its regulated revenue. But it is relatively indifferent to how this is done.
[5] and if they are not, all bets are off as to how they might respond

1.5 Structure of this report

The report devotes a chapter to each of the customer scenarios listed below:

- incremental consumption for an existing load customer;
- a new load customer entering the market;
- a new generator customer entering the market;
- customer participation in transmission planning processes
- customer exit

Within each chapter, the relevant provisions and impacts of the TPM will be explored. The financial impacts will be illustrated by comparing them to those of a conventional posted tariff that has similar effects. Conceptual and practical aspects of these equivalent tariffs are explored. Finally, alternative approaches are considered that could make transmission pricing simpler and/or more efficient, whilst providing similar price signals to customers.

2 EXISTING LOAD CUSTOMER: INCREMENTAL CHANGES

2.1 INTRODUCTION

The first situation to be considered is that of an existing load customer. The basic question that the customer wishes to answer is: "if I consume an additional 1kWh of load in a particular trading period, how much will my transmission charges increase as a result?"

This question - and others like it applying to other business inputs - are fundamental to how businesses plan and operate. Every electricity purchasing manager will be expected to have the answer at their fingertips. It is a quite different perspective to the EA's and Transpower's. But it is the only one that matters to electricity-consuming businesses.

For simplicity, it is assumed here that "other things are equal". We are comparing the customer's transmission charges in two hypothetical worlds which, apart from the change in the customer's consumption, are identical.

It is also assumed that the change in consumption is relatively small, so none of the TPM's re-openers – that apply only to *large*[6] changes – are triggered.

A load customer pays the residual charge (RC) and various benefits-based charges (BBCs), each of which is attributable to a benefit-based investment (BBI): a transmission project to which the BBC methodology applies. It will pay various other charges, such as connection charges, but these are unlikely to be affected by small changes in consumption and so are ignored. The two charge components are considered separately in the following two sections.

2.2 RESIDUAL CHARGE

Whilst the RC was originally envisaged to be fixed, more recently an indexing component has been introduced into the TPM, whereby it is increased in proportion to changes in annual energy consumption. This indexation is lagged: the RC in year Y is indexed based on the energy consumption over the period Y-8 to Y-5, compared to the consumption over the *baseline period*: financial years 2014-2017. From the customer's perspective, this means its consumption decision in year Y will not affect its charges until Y+5 and will continue to affect charges through to Y+8, after which the effect will lapse[7]. So it is simply a "buy now, pay later" deal, akin to those advertised at computer megastores and the like. A rational consumer will factor that payment delay into its purchasing decision. If the nominal increase in the RC over that future period is $X per MWh of consumption increase, the customer will take account of that cost, but discount it because it is not payable until several years in the future. The discount rate will reflect the customer's weighted-average cost of capital (WACC). The customer might

[6] the TPM defines "large" as greater than 10MW

[7] assuming this is a one-off decision: eg to run the factory over the weekend for a month, to catch up with an order backlog. Decisions which have a continuing impact – eg to invest in a new electricity-consuming asset – are similar to customer entry which is analysed in the next chapter

then apply an additional discount, reflecting its perception of the durability of the latest TPM, and so the likelihood that it will still be in operation when the bill falls due[8].

Let us say that this discounting leads to a 50% discount in present value terms. So if the nominal RC adjustment is $X/MWh, the customer will treat this as costing it 50% x $X/MWh and make its consumption decisions accordingly. To first order[9], the customer will respond in the same way to a delayed payment of $X/MWh as it does to an immediate payment of 50% x $X/MWh. So, the EA could have saved a lot of complexity in the TPM[10], simply by setting a conventional tariff of 0.5 x $X/MWh[11].

There is an apparent paradox here. Whilst each load customer is only paying around half the nominal RC, in present value terms, Transpower is not affected; it is still receiving the same revenue, on the same payment terms, despite its customers, in effect, paying 4 to 8 years in arrears. How can this be? The answer is that Transpower benefits from a "double[12] charging" of every load customer for its consumption over the period leading up to the transition to the new TPM. I realize that this will be a contentious statement, and so I will elaborate on it below.

From Transpower's perspective, it continues to seamlessly receive its allowed revenue every year, as we transition[13] from the old TPM to the new one. But this is not how the customer sees it. For example, its payments to Transpower in 2018[14] will depend upon its consumption in 2018 in accordance with the old TPM[15]. But the RC under the new TPM requires that the customer pays for that 2018 consumption, *a second time*, under buy-now-pay-later, progressively over the period 2023 to 2026.

Put another way, if our hypothetical customer had correctly anticipated, back in 2018, how exactly the new TPM would turn out, it could have reduced its 2018 consumption and have been rewarded twice: by savings in the RCPD charge and again, 5-8 years later, by a reduced RC charge.

In a present value sense, if not under a conventional cash-flow perspective, this double-charging then gives Transpower a "war chest" which it uses to fund its buy-now-pay-later offer under the new TPM; in effect, giving its customers a (roughly) 50% price cut. To take an analogy, a government could similarly cut income taxes for everyone simply by levying income taxes for the period 2014-18 on taxpayers a

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[8] and, by implication, that, were the TPM to be replaced before this, this payment liability would not be carried forward into the new regime.
[9] in practice, a customer's WACC would depend upon its level of debt, but this is a second order effect
[10] and, as we shall see in later chapters, it *does* create complexity, due to the need to consider how to treat customer entry and exit
[11] albeit that this simpler approach would *not* discriminate between customers depending upon their WACC. But it is not clear that this is an important or useful feature of the TPM.
[12] well, not strictly double, as the RC only seeks to raise around 70% of Transpower's allowed revenue initially. So really "1.7x charging"
[13] in 2022, as I understand it
[14] the year 2018 is chosen because it is after the baseline period (2014-17) but prior to the commencement of the new TPM. This means that the RC appears at the margin as an energy charge, as discussed above. Over the baseline period, the RC is instead based on anytime maximum demand, so the argument is somewhat different, although there is still a kind of double charging for consumption over this period
[15] ie based on its contribution to the regional coincidental peak demand (RCPD)

second time around. Governments would never get away with that of course; somehow, the EA has managed it.

The discussion above notes the nominal $X/MWh that each customer pays. As with any variable tariff, this will vary annually, as both the charging base (total market consumption) and the target RC revenue vary. However, whilst the RC *appears* to be uniformly applied to every customer, each customer's RC tariff will in fact be different. This is because the base level of charge depends upon the customer's anytime maximum demand (AMD) over the baseline period, so customers with lower load factors (ie proportionately higher AMD compared to average demand) will pay a premium price. Because these baseline AMDs are locked in, there is nothing the customer can do to change this[16]: its RC tariff will, for all time, depend upon what its load factor was over the baseline period.

The EA's aim with the design of the RC is to reduce any inefficient consumption behaviour that arises in an effort to avoid or reduce the charge. This is a conventional objective of taxation: and the RC is in economic terms – at least as the EA has framed it – tax-like[17]. Clearly, other things being equal, reducing the price by half[18] will reduce inefficiency. But other things are not equal. Because as well as changing the tariff level, it has also changed the effective tariff *structure*: from a peak demand (RCPD) charge to an average demand charge.

Whilst the EA's concerns about inefficiencies from the RCPD have been well canvassed and discussed, there has been limited consideration of the relative merits and efficiencies of a flat tariff[19]. Perhaps a flat tariff is more efficient than an RCPD, perhaps not. Possibly other structures are more efficient than either. It is odd that such a critical decision has not been fully examined or justified.

As discussed above, the price discount has been introduced through the "buy-now-pay-later" mechanism of lagged charging; it has been funded by double-charging of consumption over the final years of the old TPM. In effect, this just replaces a fully-variable charge with a charge that is part-fixed-part-variable, with the fixed part based on the baseline consumption. Well, if this is desired, why not just introduce this directly[20], without the elaborate complexity of buy-now-pay-later. As we will see in the following chapters, that creates substantial difficulties and complexities, for no obvious gain.

[16] apart from large changes that trigger a reopener
[17] it has the same revenue raising objectives as a tax, but is not payable to government like a true tax
[18] and a bit more, as some Transpower revenue is now recovered elsewhere, through the BBCs
[19] partly because this was only introduced at a late stage in the TPM review
[20] not that I would support this, but if the EA is determined to do it, at least make it as simple as possible

2.3 BENEFITS BASED CHARGES

Each customer will face multiple BBCs: one for each BBI that it is deemed to benefit from. BBCs for pre-2019 BBIs are fixed: they do not depend upon future consumption and so can be ignored for the purposes of this section.

BBCs for post-2019 BBIs *do* depend upon future consumption. The BBC method allocates the cost of the BBI between regions (and also between load customers and generator customers). The regional BBC charge is then allocated between customers in the region in proportion to either the coincident peak demand (for "peak" BBIs) or average demand (for "non-peak" BBIs) of each customer. So this effectively creates a $/MWh tariff for each relevant BBI, relating a customer's consumption to the BBC it becomes liable for.

Like the RC, a customer's BBC in a year is based on past, not current, consumption. Specifically, since the BBC is determined and then locked-in at the time of the BBI, the BBC depends only on consumption prior to the BBI *event*: the point in time where the BBI is committed by Transpower, and the associated BBCs are calculated.

The provisions for calculating BBCs are complex, and it is not immediately clear to me the exact historical period that would be used for selecting the relevant historical consumption metrics used in the allocation algorithms. For illustrative simplicity, I will assume that it is the 5 years immediately prior to the BBI event. Turning this around to the customer's perspective, a consumption decision in year Y will impact BBCs relating to BBI events in years Y+1 to Y+5 (or similar). Thus, in making a consumption decision, a customer will have to first:

- identify all of the BBI events that are likely to occur over the next five years;
- identify the particular BBC method that is likely to apply to each BBI;
- model each BBC method, for each BBI, to assess effective tariff – on peak or average demand – of that BBI; and
- add all of these component BBC tariffs together, to estimate the total effective tariff.

Unlike the impact of incremental consumption on RC, which only lasts for 4 years or so, the impact on BBC continues[21] for the *life* of the BBI: ie decades! Put another way, in present value terms what is at stake is not a change in the annual BBC but rather a change in the customer's contribution to the entire cost of the BBI: given that, in NPV terms, the aggregate future BBCs from all customers must equal the capital cost of the BBI. This outcome is illustrated in figure 1 below.

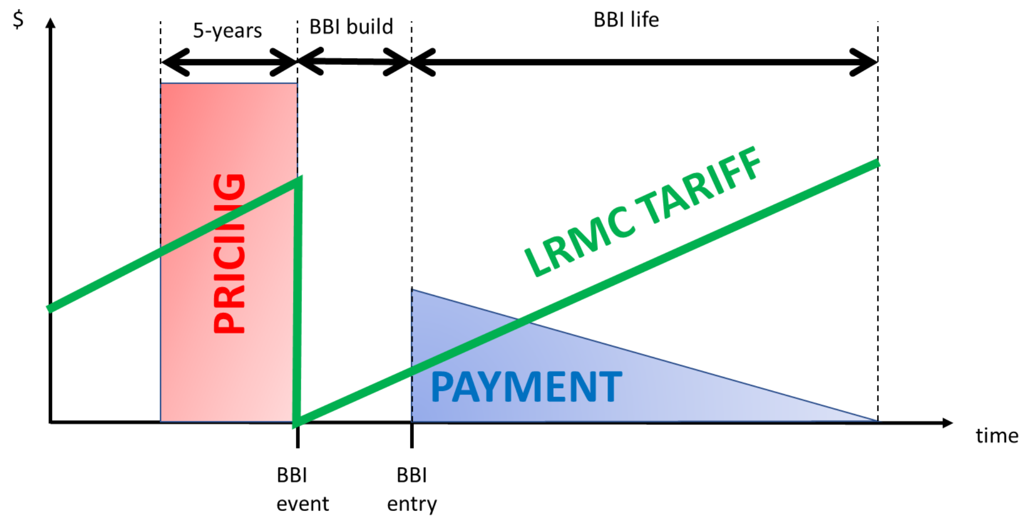

Figure 1: Equivalent pricing for future BBIs for an existing customer

Although Transpower receives revenue from BBCs to cover the cost over the BBI over its economic life, from the customer's perspective, this is again on a buy-now-pay-later. The customers contribution to the BBC is entirely based on its consumption in the few years leading up to the investment decision, and this is represented as the equivalent tariff in figure 1. Included in the figure is a stylised representation of a conventional long run marginal cost (LRMC) based tariff, where the customer contribution reflects its (notional) impact in bringing forward the need for the BBI. Whilst this LRMC approach was rejected by the EA, the similarities to its chosen TPM are obvious. Indeed, the BBC could be seen as an extreme version of an LRMC curve[22].

It is unclear to me whether the EA intends that the BBC *should* elicit a consumption response from customers. If there *is* a response, this should ideally be efficient; what the customer saves in reduced charges should correspond with what Transpower saves in reduced costs. That is the conceptual basis for LRMC-style charging; the LRMC tariff reflects the avoided transmission costs.

[21] assuming no re-openers

[22] noting that the BBC price shown implicitly assumes a perfect foresight from the customer: ie it knows *exactly* what is going to happen over the next 5 years. In reality, uncertainty around future investment grows with the forecasting horizon, meaning that the customer would tend to discount the BBC price further ahead of the BBI event.

As noted, the BBC bears some resemblance to an LRMC tariff, and so could engender similar efficiency gains. For example, if a large BBI was in the offing, customers likely to benefit might reduce their consumption in anticipation; this, in turn, might allow the project to be deferred. However, if the EA's intention is to engender such a response, an LRMC tariff would be preferred, due to its simplicity and transparency[23]. As discussed above, the challenge for a customer - to infer what effective BBC tariff it is facing at any point in time - is immense. The task is perhaps most feasible for small BBIs where the simple BBC method is applied. But these are the BBIs where customer decisions probably have least impact on investment timing or cost; if a line needs to be refurbished – say – on a particular date, the actual flows on the line may have little or no effect on that timing.

On the other hand, if the EA does *not* intend that customers respond, it has placed a complex and risky burden on customers for no reason. And the impact is not just on customers. If customers do decide to take "evasive action" in the face of an imminent large BBI, say, then this could confound Transpower's planning processes, as it sees demand for transmission capacity fall away just as it is planning to expand it[24]. The EA might respond that this effect will not be material. But, if the impact of levying the full cost of a new BBI over just four years' consumption has no material effect, why would the EA be so concerned about inefficient responses to conventional transmission tariffs, that spread the cost over *40* years?

[23] the EA has previously argued against an LRMC tariff on the grounds of its complexity and volatility. Which is ironic, given the complexity of the TPM it has delivered, which ends up looking like LRMC anyway.

[24] again, there is a similar dynamic with LRMC pricing. However, the effect of customer response under this regime is smooth: a load reduction might push back the investment by a year, say, with a consequent adjustment to the LRMC tariff. In contrast, with BBC, it is all or nothing; either the BBI is due to occur within the relevant window (in which case the customer is liable for its share), or it is beyond that window (in which case the customer has zero liability). This is reflected in figure 1: a sawtooth LRMC curve versus a stepped BBC curve.

2.4 CONCLUSIONS

For small changes in consumption by an existing customer, transmission charges may be fixed or variable: BBCs relating to *historical* BBIs are fixed, whereas BBCs relating to *future* BBIs, within the relevant time window, are variable, as is the RC. For each of the variable charges, payment lags consumption: service provision is, in effect, on a "buy-now-pay-later" basis.

For RC it is simply the case of lagging payment by 4-8 years, which has the present value effect of reducing the transmission price by around 50%. Transpower does not suffer from this payment delay, by virtue of being permitted to, in effect, double-charge existing customers for their consumption over the years immediately prior to the TPM change: once under the old TPM regime and again, on a delayed payment basis, through the RC.

For new BBIs, the payment timing is less clear but, roughly speaking, the BBC for a BBI is based on consumption for the few years prior to the time the BBI is committed. This timing is reminiscent of an LRMC-style tariff, where tariffs rise in advance of the investment and then fall to zero once the investment occurs. There is something to be said for this LRMC approach, but it is surprising that the EA has implemented it by proxy, given that it strongly rejected this LRMC alternative when it was put forward during the development of the TPM.

Unlike a conventional LRMC tariff, the BBC methodology – and even the BBIs on which this is applied – are likely to remain uncertain to the customer at the time of their consumption: ie several years in advance of the BBI commitment. This uncertainty will add substantial risk to customer decision-making and associated profitability.

In the light of the TPM's similarity to these corresponding conventional approaches, it is remiss of the EA not to have properly considered these simpler alternatives. It could have saved itself a lot of trouble – including around the design of the various reopeners discussed below – if it had done so.

3 NEW LOAD CUSTOMER

3.1 INTRODUCTION

This section considers the transmission charges applying to a new load customer[25] and the incentives these create. This scenario differs from the incremental usage scenario in the previous section; in two main ways. Firstly, it is likely to trigger various reopener provisions in the TPM, either because the customer is entirely new and/or there is an associated large step-change increase in load. Secondly, the customer potentially has a choice of location, including whether to be embedded; clearly this choice does not arise for incremental consumption by an existing customer.

Furthermore, whilst our existing customer was notionally deciding on a one-off increase in consumption within a single trading period, our new customer is making an entry decision which will commit it to some future consumption for the life of its new plant: so, potentially for decades.

The next chapter considers a new generator customer. The TPM applies shared or similar approaches to load and generation in several aspects. To avoid unnecessarily repeating myself, I will make some assumptions about the new load customer that distinguish it from a typical generation entrant:

- it does not use a shared – or potentially shared – connection point;
- it has the opportunity to choose to be embedded: ie to connect to a distribution network, rather than the transmission network directly; and
- by itself, it is not of sufficient size to trigger a new BBI through its entry.

Similar to the previous section, I will take the customer's perspective: what future transmission charges will they pay, or be likely to pay, for different investment and location decisions.

3.2 RESIDUAL CHARGE

As with the case of an existing customer, a new customer pays a residual charge based on its energy and load factor, and this is paid on a buy-now-pay-later basis that effectively discounts the charge based on the customer's WACC and its perception of the TPM's durability. Unlike the existing customer, however, its load factor is not locked in, because it had no consumption over the baseline period[26]. Instead, the TPM provides that this baseline is estimated by Transpower in order that the RC tariff can be decided.

It is not entirely clear from the TPM how Transpower would do this. Since the RC is not applied until 4 years after the customer's entry, it would be quite feasible simply to use the customer *actual* load factor over the first 4 years, analogous to how existing customers are treated. However, unlike for existing customers without a time machine to revisit the baseline period, the new customer could then potentially design its new plant – and manage its operation over the first 4 years – so as to maximise its

[25] or an existing customer establishing a new premises, who is treated the same as a new customer under the TPM
[26] and, correspondingly, it is not "double charged" for its baseline consumption.

load factor and so minimise its future RC. Clearly, as a tax avoidance action, this would be inefficient, and the EA is keen to avoid the customer being able to do this[27].

Instead, the TPM provides for Transpower to somehow estimate the customer's load factor – apparently independently of the customer's actual consumption - but offers no detail on how or when this would be done. The new customer ideally needs to know what charge it is likely to be up for *before* it is financially committed to its new premises. But it is unclear whether Transpower would be able or willing to make its load factor estimate at this point in time.

The TPM also provides for Transpower to change its initial estimate: but only to do this once. Again, it is unclear why, how or when Transpower would do this. This provision leaves the customer in financial jeopardy until that correction is finally made.

To avoid this uncertainty, an entering customer could decide to be embedded: that is, connect to the network of an existing transmission customer - typically an electricity distribution business (EDB) – instead of directly to the transmission grid. That new embedded customer would cause the EDB to place an incremental load on the grid and the TPM treats this like it would for any other load customer, as discussed in the previous chapter: ie the EDB is charged at the RC tariff, on the usual buy-now-pay-later terms. For simplicity, it is assumed that the EDB simply passes these extra charges on to the new embedded customer.

Recall that an existing customer's RC tariff is in inverse proportion to its baseline load factor. So, other things being equal, the new embedded customer will prefer to connect to the EDB with the best baseline load factor and so the lowest RC tariff. The baseline is immutable[28], so the best EDB today will be the best EDB forever, in this respect. Note that, in this scenario, the load factor of the new embedded customer themselves is irrelevant, as is the impact it has on the EDB's load factor. So, this route will be particularly favourable for a customer with a poor load factor, compared to the alternative of a direct transmission connection[29].

In summary, a new customer connecting directly to the transmission grid will face a RC tariff, but it is unclear if it will know with certainty what this is before financially committing to its entry. The preferred route might be to connect to an EDB, whose RC tariff is known and fixed.

3.3 Benefits-based Charges

In relation to BBCs, a new customer has some similarities with, but also some differences to, an existing customer. Basically, whilst both are able, through their decision-making, to affect their share of *future* BBI costs, as discussed above, only the new customer can affect its share of *historical* BBI costs[30]

[27] although this inefficiency could potentially be addressed by an appropriate prudent discount framework, in which the customer demonstrates to Transpower how it *could* potentially improve its load factor, and the cost of doing so. It can then be awarded a discount on its RC, equivalent to the net saving it would hypothetically have enjoyed if it had taken that avoidance action.

[28] as I understand it, there are no reopener provisions for existing customers in relation to the RC.

[29] it is possible that the TPM's prudent discount policy *would* apply in this case, at least to some extent, so that the customer may not need to incur the extra cost of being embedded simply to enjoy a reduction in its RC

[30] the existing customer still pays the latter charges, but its share is locked in, based on baseline consumption

In regard to future BBIs, whilst the existing customer (deciding on one-off incremental consumption) is concerned only with BBIs likely in the next few years, the new customer (deciding on ongoing, decades-long consumption) must be concerned with *all* future BBIs, discounted back to a present value. Of course, even under a conventional pricing regime, the new customer must make some assessment of the likely trajectory of transmission tariff over the life of its new assets. This is not an argument that tariffs shouldn't ever change (which is impossible anyway) but rather that the more transparent and stable tariffs can be, the better decisions the entering customer can make.

For *existing* BBIs the regional cost sharing – and associated BBC tariffs – are known and largely fixed[31]. For the BBIs existing today, EA has already calculated the various BBCs, and hard-coded the associated BBC tariffs – being the aggregate of the BBCs across all existing BBIs - into the TPM. As new BBI events occur, it should be straightforward for Transpower to update these BBC tariff tables so that any entering customer knows, to a reasonable degree of certainty, what BBC it would face for any particular choice of location.

Like with the RC, because the new customer has no actual baseline consumption, it is left to Transpower to estimate the baseline consumption metrics[32], to which the BBC charges are applied. As with the RC, the customer is in financial jeopardy until those estimates are made and fixed, and ideally this would be done before the customer has to financially commit to entry.

If the customer decides to be embedded, its BBC will depend upon its size: ie whether it is deemed "*large"* (>10MW peak) or not. The TPM requires that a large, embedded customer is treated identically to an equivalent customer connected directly to transmission[33].

On the other hand, if the customer is small (ie not "large"), it is unclear what its BBC charges will be[34]. Like other customers, an EDB's BBCs are usually fixed, but reopeners provide for adjustments to these when a grid exit point (GXP) is added or expanded. The EDB might reflect this situation in its pass-through charge to the new embedded customer; for example, it might apply an LRMC-style charge, reflecting the extent to which the new customer causes this GXP expansion (and associated BBC increase) to be brought forward.

[31] they only vary if other customers enter or exit

[32] these will be either average demand or coincident peak demand, depending upon the nature of the BBI

[33] that is to say, the EDB is charged accordingly and is likely to pass this new charge through to the new embedded customer.

[34] in fact, the pass-through of transmission charges to embedded customers in general is unclear. It may be covered by current or future EDB regulation, or it might be left to the EDB to decide

3.4 Discussion

It is seen that, for a new customer, the RC and BBCs together operate similar to conventional arrangements, with posted tariffs signalling favourable locations for the customer to connect, largely reflecting costs of pre-existing, sunk investment. In itself, this might seem a surprising outcome, given that the EA's philosophical position from the start has been to reject this conventional approach, because of concerns that this will lead to inefficient decision making; with a preference that customers only face the cost of *future* investments, which they can participate in the process of designing. But, of course, that Quixotic objective was never achievable, even if it were desirable (which it wasn't).

As discussed above, the tariff that the new customer faces is made up of three components:

- *the RC*: a flat energy tariff, whose nominal value is known with reasonable certainty, but this is clouded by uncertainty around the deeming of the baseline load factor;
- *historical BBCs*: again, these will be known with reasonable certainty: they will vary by location based on the location and use of the various historical BBIs; they may also vary structurally (eg levied on coincident-peak or average demand) depending upon the particulars of each BBI. It should be straightforward for Transpower to maintain tariff schedules for this component, for every existing GXP[35]; and
- *future BBCs*: these will be uncertain; but discounting will substantially reduce the present value of these, with the exception perhaps of large and imminent[36] BBIs.

Currently, the split between RC revenue and BBC revenue is about 70:30, reflecting the EA's choice of which historical investment projects to treat as BBIs. The buy-now-pay-later treatment of RCs[37] probably reduces their present value to a new customer by around a half, leaving these two components fairly evenly matched. If we assumed, say, a thirty-year engineering life for transmission assets, around a third will be replaced or renewed over the next decade: roughly the key timescale for the new customer, given the impact of discounting. So the "future BBI" component might, in present value terms, be similar to the "historical BBI" component. Thus, at the outset, these 3 components may be similar in magnitude[38]. Progressively, as non-BBI assets are replaced with new BBI assets, the RC component will fall to zero, and the historical BBI component will take its place, leaving (say) a 70:30 split between the historical and future BBI components; again, in present value terms as seen by the entering customer, choosing its location.

[35] a new customer connecting through a new connection point would face the same BBCs as a nearby GXP, so long as is it was deemed to be in the same region as that GXP for every historical BBI

[36] with reference to the time the new customer enters

[37] as I understand it, there is no corresponding lag for BBCs on historical BBIs. These are payable as soon as the customer enters, or at least in the following tariff year

[38] based on this cursory analysis. I am not aware of any official calculations, by the EA or TP, on this question. Of course, it depends upon the customer's WACC

In this eventual future, all (then) existing assets will be BBIs and governed by the BBC methods. To get an indication of what this future might look like, we could "fast forward" by applying BBC methods to *all* assets existing today, rather than just those that the EA has selected to be BBIs. Notwithstanding what the EA asserts in its consultation paper, it would seem to me to be straightforward to apply the simple method retrospectively in this way[39].

In this far future, the new customer faces a locational tariff which applies to its chosen level of consumption: that is, it is in essence a variable tariff[40], but only at the time of entry. This locational tariff will be based around actual or modelled flows or congestion through every transmission asset, discounted according to the assets age. So the geographical "tilt" of the tariff level across NZ will broadly reflect predominant power flow directions, offset somewhat by the occasional reverse flows that can occur in unusual conditions: eg dry years. If this sounds familiar, it is basically the premise of the Tilted Postage Stamp (the TPS) concept.

So are we fated to eventually – after 10 years of TPM discussions and a further 20-or-so years of new TPM operation – end up with something looking like the TPM that we "first thought of": the TPS? Well, yes and no. There are some similarities between the two methodologies, but also some fundamental differences.

The differences are:

1. the TPM is hugely complicated and uncertain;
2. the TPM takes decades to reach this point;
3. for historical[41] BBIs, the BBC is levied on estimated rather than actual consumption; and
4. layered on top of this tariff is the LRMC-style application of charges relating to imminent BBIs, as discussed in the Existing Customer chapter.

These are considered in turn.

Firstly, complexity and uncertainty are never helpful and should be avoided or minimised wherever possible. However, the complexity inherent in the simple BBC method itself is not unreasonable or disproportionate. It is similar to the complexity of other transmission pricing methods: eg in Australia or the UK. Most importantly, the method is applied mechanically; there is little scope for Transpower discretion[42] and it would be feasible for customers to run their own models[43]. However, where the standard method is applied, there is significant uncertainty due to the scope for Transpower discretion.

[39] And, since this simple method is designed to be reasonably reflective of the standard methods, this should be adequate for this purpose.
[40] albeit transmitted via the proxy of Transpower's estimates of baseline consumption
[41] at the time the customer enters
[42] except in the definition of pricing regions, which could also be prescribed
[43] in Australia, the Cost Reflective Network Pricing method is complex, but is run using a software application which is cheaply available commercially for any customer to purchase and run

But where the complexity mostly arises is in how and when the BBC methods are applied. In a conventional approach, the pricing method is applied to each transmission asset in each year, based on recent historical flows. As this is repeated annually, the tariff changes gradually, reflecting both changing power flows and the gradual introduction of new assets and exit – or depreciation – of old assets. In the TPM, whilst the asset mix also changes gradually, the flows are locked in for each BBI, at the time of the BBI event. Thus, the BBCs reflect that historical snapshot rather than current conditions. For the EA, this is a deliberate feature, but I see it is as an unnecessary complication. It is not clear how material this distinction is.

On the second difference, if this long transition is a deliberate "feature", not an inadvertent "bug", it can easily be applied explicitly: ie the new TPS/BBC tariffs could be published immediately, but would then only be introduced gradually over time, using a prescribed transition path[44]. However, it appears that the EA in fact sees this slow transition largely as a bug. It has previously argued that it has included *some* historical BBIs because it can and should; ie it is only for practical reasons that it has not treated more (or even all) assets as BBIs. As noted, the simple method would seem to overcome those practicalities and leave the way open to treat *all* legacy assets as BBIs.

It is questionable what the third difference (the Transpower estimation) really achieves. It is useful to distinguish here between long-run and short-run responses to tariff signals. The existing customer, in the previous chapter, is making *short*-run decisions: it has already chosen a location and capital stock, and is simply making decisions about which assets to operate. The new customer will make these short-run decisions too, but is also making long-run decisions: deciding what capital to invest in, and where to locate it.

Now, using estimates rather than actuals will certainly affect short-run decisions. As we saw with the existing customer in the previous chapter, because historical BBCs are predicated on a baseline that cannot change, they are effectively fixed. This will be true for the new customer too, once they become "existing": ie once their baseline is decided by TP.

But the estimation process does not (or at least should not, assuming Transpower does an accurate and timely job of it) affect the long-run decisions associated with entry[45], because these are taken before the baseline is determined and so before the historical BBCs become locked-in. In short, the historical BBCs are variable for the purposes of long-run decisions but fixed for the purposes of short-run decisions.

The question, then, is whether all of the complexity of the TPM is justified in relation to improving the efficiency of *only* short-run decision making[46]. Generally, short-run responsiveness to price[47] is quite low compared to long-run responsiveness. Furthermore, dead-weight losses are roughly in proportion to the square of responsiveness. Thus, if there is any efficiency loss due to responding to historical

[44] whether gradually replacing the RC or the old RCPD tariff. Either would be feasible, but the latter approach, transitioning between the old TPM and the new TPM, corresponds to conventional good practice
[45] ie the customer deciding on the size, configuration and future operation of its new assets, on the assumption that Transpower will correctly reflect its choice when it does its estimation
[46] acknowledging that the EA also has an objective of improving transmission planning, discussed in the next chapter
[47] ie price elasticity of demand

BBIs[48], this would overwhelmingly arise from long-run decision making, and the TPM does little to address or mitigate this. Any potential efficiency gains from improving short-run decision-making are unlikely to be substantial enough to justify the complexity of the historical BBI arrangements[49].

On the fourth and final point above, the EA has explicitly rejected an LRMC-style pricing regime, so would presumably not be averse to removing this aspect of the TPM.

In summary, despite being disguised under multiple layers of confused, complex and *ad hoc* provisions, the TPM will appear to the new customer quite similar to a conventional TPS-style tariff, at least in terms of long-run decision making.

3.5 Conclusions

A new load customer essentially pays a locational, variable tariff consisting of the RC, historical BBIs and future BBIs. Whilst these charges are only fully-variable in terms of their long-term decision to enter (short-term decisions, discussed in the previous chapter, are a mixture of fixed and variable), it is this kind of decision for which transmission tariffs have the biggest impact.

The EA could have provided substantially the same long-term incentives simply by designing a Tilted Postage Stamp (TPS) style variable tariff with equivalent prices. The TPS could be designed to reflect only historical BBIs – with remaining existing assets covered by the residual charge, mimicking the TPM. Alternatively, the use of the simple BBC method would allow *all* assets to be treated as historical BBIs, and so charged for on a locational, rather than postage-stamp basis. This would have advantages in terms of simplicity and certainty, and simply brings forward the outcome that we will reach several decades into the future when non-BBI assets are finally retired or replaced. Again, given that the EA rejected the TPS during TPM development, it might be surprised to find that its preferred TPM gives outcomes quite similar to this, but with more complexity and a much longer transition period.

Instead of implementing a conventional, fully-variable tariff, the EA has chosen to make tariffs quasi-fixed by relying on TP-estimated metrics for new customers: AMD for RC, and coincident and average demand for BBCs on historical BBIs. It is not clear how Transpower would calculate these estimates, or what risks are created for new load customers as a result.

[48] which the EA asserts, although I would dispute it

[49] whilst the EA asserts that there are substantial inefficiencies under the RCPD regime, it is not clear how these split between short-run and long-run concerns, nor how much of these could be addressed by an improved tariff structure alone, without the need for the full BBC regime.

4 New Generator Customer

4.1 Introduction

For the new generator customer, it is assumed that, unlike the new load customer, it is a "big fish in a small pond" whose entry is liable to trigger – or substantially change the timing of – some new BBIs for which it bears a substantial portion of the cost. It also may share its connection with existing or future generators. Finally, it does not pay the RC and, because it is "large" in TPM terms, it gains no BBC advantage – or disadvantage – from being embedded; so these aspects are not relevant in this case.

4.2 Connection versus Interconnection

There are different provisions in the TPM for new connection versus interconnection (BBI) assets. However, for shallow interconnection (or "deep connection") assets – those that primarily serve just a few local generators – the provisions are similar in outcome, if not design. The major difference is that whilst 100% of the connection cost is allocated to the connected parties, only a share of the interconnection costs will be allocated to local generators, even for shallow interconnection. It is not clear what this share will be, and it may differ for different circumstances and configurations, but it seems likely to be 50:50 or something similar[50].

A major issue for both connection and interconnection is sizing: should the new asset be *right-sized* to just accommodate the new entrant generator; or should it be *over-sized*, with some *excess capacity,* included, to economically provide for future entrants? And, if excess capacity is to be built, who should pay for it; and who should take the stranding risk, given that the anticipated future generation might never arrive?

This is a perennial problem in transmission planning and pricing. It is being exacerbated with the transition to renewables, since these projects, as well as being typically smaller than for conventional generation, are likely to cluster in geographical areas where renewable resources, land prices, transmission interconnection and planning conditions are all favourable, and multiple projects can be accommodated. I will refer to such areas as *regional energy zones* (REZs). Whilst in some jurisdictions, REZs are explicitly identified in a top-down planning process (as, say, industrial zones might be in urban planning), the term "REZ", should not be taken to imply this. Such geographical clustering is likely even in an unplanned market outcome.

Thus, whilst the connection/interconnection for a conventional project would typically be right-sized, it would likely – in many situations - be remiss and inefficient not to incorporate excess capacity when connecting or interconnecting the first-mover in a REZ.

[50] This is discussed in more detail in a separate section, below

4.3 First-mover Problem

The underlying principle of the TPM is that connection and interconnection costs are paid for entirely by the beneficiaries. In the generator entry context, this means that existing generators pay for the entire annualised connection cost and (around) half the interconnection cost. And this is true for both the capacity they actually use, and any excess capacity provided for future entrants: no distinction is made in the TPM. This creates what the EA refers to as the "first-mover problem". Given that this problem follows directly from their adopted charging principles, it is a problem entirely of their own making[51].

The problem can be seen from the perspective of the first-mover or later-movers. The first-mover pays for the entire cost (or 50% share of the cost) of any excess capacity that Transpower decides to build. It is unclear how Transpower makes this decision. For connection, one would think that this is a joint decision between generator and Transpower. For interconnection, the dynamics of this decision-making is discussed in the next chapter.

As usual, it is critical that the project investor knows what transmission charges it will face before it financially commits to the new project. At best, it might know the level of excess capacity, and its initial share of the cost under the BBC method to be used. It cannot know, with any certainty, what generators may connect in the future - and when - to share this burden.

A later-mover at least knows what the excess capacity looks like, as it is already built. At worst, it shares the burden with the earlier movers that are already there. The sharing methodology is also likely to be clear[52].

As the consultation paper articulates, the BBI depreciation schedule also means that the BBC faced by the late mover is likely to be proportionately lower (compared to the benefits received) than for the early mover, even if the first mover weren't initially carrying the can for the excess capacity.

Thus, under the TPM, there will be a strong disincentive to be first-mover, and this is likely to cause severe coordination problems around new REZ development. Ideally, the various project developers could coordinate their entry decisions, but in practice this tends to be difficult, due to commercial confidentiality and competition concerns.

[51] although, to be fair, this problem can also arise under other pricing methodologies: for example, the LRMC approach discussed earlier

[52] although, I must confess, I have not had the time to work through and digest the various methods set out in the TPM, that deal with this eventuality. It is also an area where the EA is still consulting on alternative options.

4.4 ALTERNATIVE APPROACHES

Given the importance of rapid decarbonisation of the NZ electricity system – particularly in the light of current government targets for 100% decarbonisation by 2030 – a system that throws sand in the wheels of an already challenging ride is simply not tenable. Other approaches need to be considered.

There are three, related challenges alluded to above:

- coordinating multiple projects in a REZ with the associated transmission connection and interconnection;
- the need to allocate costs fairly between first- and later-movers, so as not to discourage early movers; and
- the need to efficiently manage and fairly allocate the risks of stranded excess capacity.

In Australia, these challenges are being addressed by various state-government-led schemes to coordinate and centralise the development of new REZs. Of course, this is antithetical to the EA's preferred market-led or market-like philosophies. Australia, similarly, preferentially investigated and trialled more market-based approaches before settling on the least-worst[53] centralised approach. The earlier market-based approaches all turned out to be conceptually infeasible or practical failures[54]

In a coordinated approach, a suitable REZ is identified and "declared". Some form of open season or tender is then undertaken by the relevant central authority (in Australia, State governments) to attract and select the best renewables projects in this zone. Transmission is then designed and built to co-optimise (both in size and in detailed design) with these project bidders. Finally, the costs are shared between generators, customers and taxpayers. Potentially, for the generators, the costs payable can be part of the tendered bids, so those generators prepared to pay the most are liable to be selected. This has strong similarities to the "coalition of the willing" approach on which the EA's beneficiary-pays philosophy is founded[55], so it is perhaps surprising that the EA has not explored this concept further[56].

It is not necessarily the case that the EA should adopt this option. Indeed, it is not even clear that it has the jurisdiction to do so. However, another alternative approach is available to it, which would at least address the latter two challenges listed above, and is clearly within the scope of the TPM. This option is in plain sight in the table on page 68 of the consultation paper which illustrate the first-mover problem, and is replicated[57] in table 1, below.

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[53] like Churchill's democracy

[54] for interconnection at least. A new market-based approach for radial connections and extensions has recently been promulgated by the Australian Energy Markets Commission, but is yet to be used in anger. Hope springs eternal!

[55] discussed in detail in my submission to Transpower's TPM consultation in December 2020

[56] the coalition of the willing approach is likely to work best in a situation where there are just a few, clear beneficiaries, which facilitates coordination and deters free riders. A shallow or deep connection is an example of such a situation.

[57] columns that are not relevant have been omitted

Year	BBI$	*Benefits*		*Proposed TPM*	
		First-mover	*Second-mover*	*First-mover*	*Second-mover*
1	42	20		42	
2	34	20		34	
3	26	20	20	13	13
4	18	20	20	9	9
Average		**20**	**20**	**24.5**	**11**

Table 1: EA first-mover example

In the EA's example, each generator receives an annual benefit of $20 from a new BBI, which for illustrative simplicity, has just a four-year life. The investment case for the BBI is based on the immediate entry of a first-mover and the anticipated later entry of a second-mover in year 3. The WACC is zero, again for simplicity, so the annual BBI cost reflects the economic depreciation of the asset. The asset cost is $120, and this happens to exactly match the aggregate benefit receive by the 2 generators.

The annual BBCs for each generator in each year are then calculated under the rules of the proposed TPM, which requires that the revenue relating to the BBI is fully paid for in each year of operation by the generators existing in that year[58]. This means that the first-mover pays the full annual cost until the second-mover enters, after which the cost is shared equally

The outcome is that the first-mover and second-mover pay annual average BBCs of $24.5 and $11, respectively, despite enjoying identical annual benefits[59]. As discussed above, there are two drivers for this anomaly: firstly, that the first-mover pays the full cost in the early years, whilst the second-mover only ever pays half the cost; secondly, the depreciation means that the cost is higher in the early years where only the first-mover is present.

The alternative approach that I am proposing is simply for each generator to pay the same amount in each year it is in operation. In this case, since the total cost is $120 and the total generator-years of operation is 6, the annual cost needs to be $20: ie 6 x $20 = $120[60]. Thus, in the example, the annual BBCs are identical to the annual benefits, for each generator in each year.

[58] in practice, only around 50% would be paid, with the remainder paid by load customers, but that does not matter for the purposes of illustration

[59] the EA has considered, but ultimately rejected, a possible second approach which would correct this anomaly, by charging the first-mover less than the second-mover in the years when both are in operation. Because the EA rejected this approach, it is not considered here, and is excluded from table 2 for illustrative simplicity.

[60] since the WACC is assumed to be zero, the NPVs are just the arithmetical sums. In the general case, with a positive discount rate, the annual tariff could be adjusted accordingly so the NPV of costs and payments match.

In practice, the benefits will substantially exceed the costs. But, nevertheless, the BBC can be set on the same basis:

- run the BBC method in the normal way to calculate the share of the total BBI cost that generators should pay (=$120 in the example);
- calculate the net present value of the generation forecast, using the relevant generation metric; (=6 years, in the example);
- divide the first number by the second number to calculate a tariff (= $20 per year in the example); and
- charge this tariff to each generator for the years that they are in operation.

In the example, both first- and second-movers pay $20 each year they are in operation. So there is no advantage or disadvantage to being first-mover or later-mover. Furthermore, this BBC method automatically aligns with the EA's principle that BBCs are proportionate to benefits.

The fundamental difference of this approach to the EA's, and presumably the reason why it has not adopted it, is that it does not recover the annualised BBI cost in each year[61], so it violates one of the EA's fundamental principles[62]. As seen in the table, it is likely to under-recover in the early years: both because some generators have not yet entered and because the BBI is un-depreciated. Correspondingly, it is likely to over-recover in later years. However, if generators enter as forecast, the present values will equate, because the BBC tariff has been calculated precisely to achieve that end.

The annual unders and overs could either be borne by Transpower or could be recovered through adjustments to the RC. Given that these unders and overs will occur separately over each BBI, they are likely to average out and the aggregate impact may be small.

If the later entrants do *not* arrive as expected, some of the excess capacity will be stranded, and its cost borne either by Transpower or by load customers through the RC. However, given that *somebody* has to bear this cost, this approach of spreading the risk widely seems most fair and efficient[63].

In contrast, the EA proposes to allocate this stranding risk to early movers[64], which is neither fair nor efficient. Given that these early movers gain no benefit at all from the excess capacity, particularly if it is

[61] in the example, in year 1, say, the BBI cost is $42 but the total BBC would be only $20.
[62] which, incidentally, it has never satisfactorily explained or justified. It seems philosophically inconsistent to be strict about BBCs having to exactly fund each BBI, but be quite casual about the fact that 70% of the assets initially are not BBIs and so the costs can simply be smeared through the residual charge
[63] and, of course, it is also possible that *more* generators will enter than forecast, meaning an *over*-recovery in the BBC
[64] and note that its alternative option, of requiring that late-movers pay a higher BBC, does not address this stranding risk either, because if the late-movers never arrive they cannot pay anything

never used, this approach is in contradiction to the EA's beneficiary pays philosophy, aside from creating the first-mover problems discussed[65].

As an alternative, the EA considers the possibility of the cost of excess capacity being borne by other customers within the same region as the BBI. That compromise makes little sense. These other customers are no more beneficiaries of the excess capacity than the early-mover generators are. And concentrating the costs and risks within the region does not address the fundamental problem of fairness and efficiency[66].

4.5 The 50:50 Question

One important aspect of the proposed BBC methods that I have not yet discussed is the division of the BBI cost between the load and generator sectors. This aspect was never considered explicitly during the development of the TPM guidelines, because it was always assumed that the BBC modelling would deliver the answer. That is to say, the EA was philosophically reticent to propose a hard number, because it believes that charges should reflect benefits, and the sharing of benefits between sectors will differ for each BBI[67].

But, with the delivery of the TPM, it can be seen that, whatever its philosophical justification, this approach was really just "kicking the can down the road". It was always going to be hard for any BBC method to answer the question, because the answer depends primarily upon the impact of a new BBI on energy price outcomes, and the wealth transfers they give rise to. It is very hard to forecast energy price outcomes in a model, especially when small price variations can give rise to large wealth transfer impacts. Not unexpectedly, and not unreasonably, Transpower has proposed – and the EA has accepted – BBC methods that are generally price agnostic. They either avoid forecasting price entirely or they make simple, hard-coded assumptions about how prices would move if the BBI is introduced. Thus, it turns out that, no, the BBC methods will *not* answer the sharing question on a case-by-case basis and, yes, the sharing in fact *does* need to be hard-coded: explicitly or implicitly, as discussed below. This is a reasonable approach[68] but it represents a failing of the TPM development process that this has only been recognised and adopted at the eleventh hour.

The hard-coding of the shares differs between the BBC methods. In the simple method, there is a simple "50:50" kind of assumption: that flows from generators and flows to loads have equal implied

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[65] the TPM obscures this anomaly by bundling the right-sized capacity and excess capacity components into a single BBI and assessing the benefits from this whole. That is convenient, but no more conceptually sound that bundling the entire transmission system into a single BBI and seeing who benefits from the grid as a whole. The EA has arbitrarily chosen a halfway house which is both conceptually and practically unsatisfactory.
[66] the EA argues that this concentration gives these customers an incentive to engage in the planning process. But forcing customers at financial gunpoint to engage in a process they would otherwise be disinterested in seems to me akin to a protection racket. And, of course, the customers' response will simply be: "*don't* build the excess capacity". Which could easily have been anticipated, without the need for financial duress.
[67] in contrast, for the RC, which does not reflect benefits, the TPM guidelines explicitly require that the sharing is 100% to load, 0% to generation.
[68] albeit one can argue whether the particular hard-coded values chosen are appropriate

value[69]. Transpower has chosen this approach on the basis that there is no obvious, *prima facie*, reason to favour one sector over the other in the algorithm. The EA has accepted this, subject to a future review of this assumption, although whether and how this review will put the question to rest is unclear.

The standard method *does* model price outcomes, but the Clutha case study[70] suggests that this will be done using hard-coded assumptions which reflect a predisposition on what the shares should be. For example, Transpower's Clutha method assumes that prices will move an equal amount – in opposite directions – upstream and downstream of congestion that the BBI is designed to relieve, thus giving equal $/MWh benefits to each sector[71].

I wouldn't assert that these are necessarily bad approaches and assumptions, but nor are they necessarily good ones. The problem is that these assumptions have never been properly ventilated and discussed – in the way in which, say, the RC sharing factor was. Despite the complexity of the TPM guidelines, this key decision has been left in the hands of Transpower: either in the TPM itself or, for the standard BBC method, in the assumptions that Transpower decides to make for modelling a particular BBI. Recall the earlier discussion around the difficulties that generator and load customers face in forecasting BBCs on future BBIs. This uncertainty and lack of transparency around something as fundamental as the sectoral sharing makes the task that much more difficult.

4.6 Conclusions

Inherent in all transmission planning decisions is how much capacity should be built in excess of immediate requirements, to economically cater for future growth. Correspondingly, a key consideration in transmission *pricing* is who should pay for the cost of this excess capacity, and who should bear the stranding risk that the anticipated growth never eventuates. The EA has decided that *existing* (at the time of the investment decision) customers should be liable for both. Whilst future customers will shoulder some of the burden, if and when they enter, their contribution will be disproportionately small, due to the impacts of discounting and depreciation. Since it is future customers – not current customers – who primarily benefit from the excess capacity, this runs counter to the EA's beneficiary-pays philosophy, and exacerbates the generational equity problem of current customers paying for assets that only future customers benefit from.

The TPM approach creates a first-mover problem – which the EA recognises but has not been able to satisfactorily address – where an entering generator triggers new investment (whether for connection or for interconnection) incorporating excess capacity for which it is required to pay the lion's share until later entrants arrive. Of course, it cannot know whether these will arrive at all. So moving first is extremely risky, and will result in a crisis of coordination: no project that is planning to connect in an area where there are likely to be later-movers will want to be the one who goes first.

[69] this does not, as I understand it, necessarily imply that the outcome of the BBC method will be an exact 50:50 sharing of the BBI costs

[70] written by Transpower and published by the EA in its pack of papers for this consultation.

[71] $ benefits between the sectors will still differ, of course, if the MWh are different

The experience in Australia has been that solving this coordination problem is critical to the transition to renewable generation. Like the EA, Australian regulators first attempted to develop arrangements where first-movers would be responsible for these costs and risks, but ultimately found these to be infeasible or impractical. These have now been superseded by new arrangements where transmission and generation entry in a REZ are centrally coordinated, and the transmission costs and risks are variously shared between entrants, load customers and taxpayers. I expect that the EA's proposals will similarly fail to meet the needs of the energy transition and be superseded.

Notwithstanding that, the TPM could be substantially improved in this area by providing that load customers generally, rather than first movers, bear the initial costs and stranding risks of the excess capacity, through adjustments to the residual charge. This will substantially help with the first mover problem, whilst imposing limited risks and costs onto load customers.

A key question in any transmission pricing policy is how to divide costs between the generation and load sectors. The EA guidelines explicitly answered this question for the RC, but not for BBC, assuming that the latter would simply be an outcome of the BBC modelling in each case. That was always optimistic; the BBC models would need to forecast energy prices – and the impact that a new BBI has on these - to answer the question, and this was always going to be problematic. Transpower has sensibly proposed – and the EA has accepted – methods which reduce reliance on this impossible task, by introducing hard-coded assumptions into their models which effectively dictate the sharing outcome.

These assumptions, broadly speaking, implement an approach of sharing costs 50:50 between load and generator customers. This has been adopted at the eleventh hour, with limited scrutiny, analysis or consultation; even the EA is uncertain that it is the right approach and has flagged a future review. This represents a major failure of the TPM review process.

5 CUSTOMER ENGAGEMENT IN THE PLANNING PROCESS

5.1 INTRODUCTION

It has always been the contention of the EA that the BBC approach will encourage customer engagement in the planning process and so lead to better planning outcomes. Now that the TPM has taken clear shape, this argument can be re-examined, from the perspective of our hypothetical customer.

To the extent that customers are large enough to play any significant role in the planning process, we can assume that they will be rationally profit-seeking in their engagement, just as they are when responding to the TPM price signals as discussed above. In short, they will only engage if the expected financial benefit to them of engaging will exceed the cost of the engagement. Furthermore, in deciding how to engage, they will aim to maximise this benefit.

Transpower will be well aware of these commercial strategies, and will second-guess or discount their contributions accordingly[72]. At best, Transpower can usefully take note, not of what stakeholders are saying, but why they are saying it, and hope to infer the truth behind the bluster[73]

In this cacophony of distortions and special pleading, customers will essentially be concerned with two aspects of the process:

- what project is built and when; and
- how the cost of the BBI is allocated between customers through the BBC method.

These aspects are considered in turn below.

5.2 DESIGN OF INVESTMENT PROJECT

As discussed in the previous section, the fundamental issue with the BBC approach is around generational equity: that existing customers pay a disproportionate share of the cost of a BBI that later entrants benefit from. Due to the depreciation schedule, this is true of all BBIs, whatever their location and purpose[74]. However, this anomaly is most pronounced in the case of “excess” capacity, where benefits only arise over the longer-term, if at all. Excess capacity is most obvious in the shallow investments discussed above. But it inevitably arises in deep projects too, where economies of scale and anticipated growth would make a planner remiss if it didn’t include some excess capacity in most cases.

[72] Unlike the courts, Transpower will not be able to threaten prosecution for perjury in order to ensure that stakeholders tell the truth, the whole truth, and nothing but the truth.

[73] in the language of economics, revealed preferences can be inferred from expressed preferences.

[74] assuming that the trajectory of future benefits is flatter than the depreciation schedule that drives future payments

Primarily it will be existing customers at the planning table – although there will be some overlap between existing and future customers: an existing SI generator, say, might be considering future NI projects and so would lobby as a "future generator" (either overtly or, more likely, covertly) in that respect. Thus, the dominant view at the table will be to right-size rather than over-size, despite Transpower's likely preference for some economic level of over-sizing. Transpower would likely ignore the clamour; if it *did* take some notice of it – which the EA's philosophy relies on - this could lead to inefficient under-sizing.

Alongside these strategic considerations, there might be some tactical manoeuvrings. Given that the BBC methods will allocate the BBI costs based on *recent* consumption or generation, a customer who has had a few lean years of low activity (or perhaps had just recently entered) might want the BBI approved immediately to take advantage of this, whilst the reverse would apply to a customer with a relatively high recent activity that is expected to decline over the short-term.

5.3 Allocating the Investment Cost

In the BBI design there is, at least, some theoretical possibility of efficiency improvement through customer engagement even if, for reasons discussed above, this seems unlikely in practice. But the BBC allocation is a zero-sum game and there is even less to gain here. That, of course, does not make the process likely to be any less contentious or fractious.

It is not clear to me whether or how the two process of BBI commitment and BBC method are entwined. Does the BBC have to be decided prior to the BBI being committed? Or only after? Logically, for a customer to be able to engage rationally in the BBI design process, it must also know what share of the costs it will bear under different BBI project options. But tying the two processes together would make an already difficult planning process more complex and contentious. Any delays in urgently-needed investment will have real costs, of course: so a zero-sum game could have a negative-sum outcome.

In my last submission[75], I discussed the BBC/BBI discussions as a kind of proxy for the negotiations that would occur in the "coalition of the willing" model[76]. But rather than offering explicit financial contributions, beneficiaries argue around the method and input parameters of the BBC modelling. In a fully transparent world where everybody had their own version of the BBC model to run, this would amount to the same thing. I think this is the underlying philosophical basis for the EA's attraction to the BBC model; as the next best thing to a market-like, coalition-based approach.

The fundamental flaw in this approach, whether an implicit or explicit coalition model, is that future beneficiaries – those for whom the excess capacity is being built – are not present, not even in the form of proxies. This contrasts with the BBI planning process, where Transpower speaks on behalf of these future beneficiaries, in the form of its growth forecasts. Logically, it should be arranged for Transpower to "put its money where its mouth is" and this would arise in the option discussed above where Transpower bears the cost initially of the excess capacity and then recovers this from new entrants

[75] December 2020

[76] In this model, which applied in NZ for a short-period, BBI beneficiaries *volunteer* to fund part of the BBI cost and hopefully – after perhaps several rounds of ratcheting contributions –enough is eventually raised to make the investment a reality

when they arrive. But Transpower's low regulated WACC is insufficient to accommodate such risks[77]. So there is no inherent financial discipline in Transpower's forecasting, beyond those implicit in the existing economic regulation.

5.4 Conclusions

The EA's hope and expectation that the TPM can be designed to encourage constructive customer engagement in the transmission planning process – and so enhance planning outcomes – has always been implausible and quixotic. In the light of the EA's decision to foist the costs and risks of excess capacity onto existing customers, it can now be seen that customers' contribution to this process will be as unhelpful as expected: they will simply urge to Transpower to minimise the amount of excess capacity created. If the Transpower were to take any notice of these representations, it would build a future grid of uneconomically small lines and upgrades. In short, the EA's philosophy requires that Transpower accommodates customer preferences, but good planning requires that it doesn't.

Inevitably tied up with the planning process will be discussions around the design and outcomes of the BBC method used to allocate the costs of the BBI. As a zero-sum game, this process is likely to be extenuated and fractious. It is not clear how the BBC and BBI processes will be inter-linked, but it seems likely that, for major projects at least, any interactions will cause both to be delayed.

The underlying problem is that a key stakeholder is missing from the table: the future customer. A reason we have independent planners and regulators is to act on their behalf in their absence. As we transition to a zero-carbon world, the needs and interests of future customers – whether in the form of new renewable generators or newly "electrified" energy consumers – loom ever larger. In this context, the EA's idea of putting existing customers in the driving seat for transmission planning is unhelpful and misconceived.

[77] in the Australian gas access arrangements, for example, regulated gas pipeline developers are permitted to fund this "speculative capacity" and earn a premium rate of return on it

6 LOAD EXIT

6.1 INTRODUCTION

At face value, a customer exit seems to be equal and opposite to a customer entry. But it is actually more analogous to the "existing customer" situation, except the customer is considering reducing load rather than increasing it. The existing and exiting[78] customers are similar in two respects:

- they both have a chosen location and sunk capital; and
- they both have payment liabilities, due to the "buy now pay later" structure of the RC and BBCs.

Of course, one key difference is that the exiting customer has no ongoing commercial relationship with TP, so there is no mechanism through which Transpower can ensure that payments can continue until the liabilities are extinguished[79]. And this obvious fact causes real problems for the TPM design.

6.2 WHAT THE TPM SAYS

Consider the existing and exiting customers as the bookends of a spectrum of load reduction possibilities: having a marginal load reduction and 100% load reduction, respectively. A marginal load reduction faces an equal and opposite price signal to the marginal load increase discussed previously, so the same effective tariffs are faced, and the buy-now-pay-later becomes "reduce-now-save-later" instead. But, for the exiting customer, payments cease abruptly: "exit-now-save-immediately". Given these quite different TPM treatments at its two ends, somewhere along the spectrum of load reductions there *has* to be a point where the TPM treatment flips from one approach to the other; a "line in the sand".

[78] spellcheck is giving me a hard time over this distinction

[79] it would seem feasible to levy "exit fees" on an exiting customer to address this difficulty, but this does not seem to have been contemplated by the EA

It is difficult to keep track of where exactly this line is, as it seems to shift with each new iteration of the TPM, and the consultation paper flags further possible movements. But it seems to look as presented in table 2, below[80]: "*S*" refers to treatment the same as a small change in load (reduce-now-save-later); "*L*" refers to treatment full exit (or payments cease immediately).

Load Reduction Scenario	*RC*	*BBC*
Small change in load	S	S
Large change in load	S	S
Reduced usage of a large plant	S	S
Derating of a large plant	S**	S
Closure of a large plant	L	S or L*
Exit of a related entity	L	S or L*
Exit of a customer and all related entities	L	L

Table 2: Line in the Sand between existing and exiting

(*) depending on whether the relevant BBI is older or younger than 10 years
(**) this is still being considered by the EA

6.3 Discussion

There are two problems with the "line in the sand" approach. Firstly, it is complex and confusing and subject to change. Secondly, wherever the line is placed, there are boundary issues: potentially a relatively small and low-cost decision by the customer can allow it to cross the line from "existing" to "exiting" and so save large amounts of money on transmission charges. Indeed, the reason for the EA's continuing concern about where exactly to place the line is due to the perverse incentives created by these boundary effects. But moving the line doesn't make the issue go way; it just changes the nature of the action required to cross the boundary.

For example, suppose a plant derating is treated as a large change. A 100MW-rated plant might run at 80MW for 99% of the time, but need to peak at 100MW for that final 1%. The opportunity cost of that 1% is being unable to derate the plant from 100MW down to 80MW. Nevertheless, the customer might decide to derate the plant, to reduces its transmission charges, despite the inconvenience of not being able to run the sunk asset at the full 100MW for that 1% of the time.

Possibly, some of these inefficiencies could be addressed by the Prudent Discount Policy[81]: so rather than *actually* derating the plant, say, Transpower would evaluate how much the customer would save (net) by the derating, and offer this as a discount instead. But that will require a new bureaucracy to evaluate, verify and approve such hypothetical actions.

[80] I might have this wrong in detail. It doesn't really matter. The point is the existence of a line in the sand, not exactly where it is located.
[81] although it is not clear whether this is permitted under the TPM

The need for a line in the sand arises because the EA has decided to lag payments behind usage: for a few years for the RC and for many years for the BBCs. The EA can either continue its quest to find the ideal location for this line[82] or remove the need for it in the first place: by moving from the idiosyncratic "buy-now-pay-later" to the conventional "buy-now-pay-now", so that a customer can simply exit with no payment liabilities to be managed.

As discussed in the previous sections, a move to this conventional approach would expose short-run decisions (with small impacts on load) to higher transmission tariffs, but will not change the exposure of long-run decisions (having large impacts) which already face the full tariff. Any perceived efficiency loss from the increased short-run exposure would be offset by the efficiency gains from eliminating boundary-issue complexities and distortions.

6.4 Conclusions

There is a fundamental flaw in the EA's buy-now-pay-later approach: the exiting customer will not be around to "pay later". So if different rules inevitably apply to exiting and "continuing" customers, where do you draw the line? Is the "customer" a load, a plant, a site, a firm, a conglomerate…? Wherever the line is drawn, a customer is then incentivised to shape shift, from one form into another, to cross that line, to change its load reduction into an "exit". In doing so, it can potentially save itself a lot in transmission charges at only a small additional direct cost to its business.

Aware of these boundary effects, the EA has had various attempts at locating this "line in the sand" and continues to propose further variations in its latest consultation paper. But these efforts are like a tax collector attempting to plug loopholes in poorly designed tax legislation; and they are doomed to fail, because the "tax dodgers" are always nimbler and more creative (and better remunerated!) than the tax collectors.

And this is all so unnecessary. By choosing to create this ramshackle, buy-now-pay-later TPM infrastructure, the EA has made a rod for its own back. As discussed in the previous chapters, conventional buy-now-pay-*now* tariff structures can provide similar incentives to the TPM, at least for the *long-term* decisions that really matter. That those simple, equivalent tariffs go by the name "Tilted Postage Stamp" shouldn't discourage the EA from adopting them, even at this late stage.

[82] spoiler: it doesn't exist

7 Overall Conclusions

In developing its TPM, the EA originally set out a stark vision of how it would look: charges would be based on customer benefits from new assets, whilst the cost of sunk assets would be recovered through fixed charges that customers were unable to avoid. But this vision was never something that could be practically implemented in its pure form, because customers will inevitably enter and exit; and fairness and durability require that entering customer pay their fair share of sunk costs, whilst exiting customers cannot continue to be charged. Once exceptions are carved out for such situations, there are immediate boundary questions as to what is a "customer" versus a premises or a large electrical plant, and why it is fair or efficient to treat one differently to the other.

So, over the latter years of the review, as we have moved from conceptual outlines through to a final implementation, the EA has introduced a series of complexities and compromises into the TPM to address these boundary issues. And, as these have added further complexity, they have also remorselessly moved the charging outcomes – as seen by the customer – closer and closer to a conventional transmission pricing regime, in which tariffs are posted and customers simply pay for their actual load or generation at these tariffs. No fixed charges; no baselines; no "buy-now-pay-later". Just a simple "user pays", like for almost every other product, in almost every other market.

With the detailed development of Transpower's modelling of transmission benefits, we can get a foretaste of what this underlying tariff might look like, as we gradually transition from the flat residual charge to the locational benefit-based charges. And it appears that this will be similar to the Tilted Postage Stamp concept which many argued for right at the commencement of this review and which the EA has consistently rejected as inappropriate and inefficient. Superimposed on this, there is a charging component looking similar to a "long run marginal cost" pricing approach; a concept which the EA has also vigorously rejected.

Customer decision-making is ruthlessly prosaic; philosophical and conceptual considerations are ultimately irrelevant. The only question that matters for the customer is: how much will this decision cost me (or save me) in transmission charges? And, when that calculation is undertaken – as this report has described – what the customer will see is effectively a Tilted Postage Stamp tariff, obscured somewhat by the complexities and uncertainties inherent in the asset-by-asset, benefit-based approach.

That, at least, is true for long-run decisions around capital expenditure and choice of location. But these are the decisions where transmission pricing is likely to have the biggest impact on outcomes and so on economic efficiency. Even if the TPM's unconventional approach were able to improve the efficiency of short-run decisions (which it won't), the economic gains would be far outweighed by the higher transaction costs and commercial risks created by its complicated new regime.

So perhaps there is a chance to "cut our losses" here. To understand what this underlying tariff looks like and simply to implement that in the TPM. Because, if we continue down the current path, it seems inevitable that we will continue to confront – and fruitlessly endeavour to resolve – the contradictions inherent in the EA's TPM vision.

Appendix C: The Authority's TPM reform analysis between 2012- 2020, including summary of options analysis and CBA results

Proposed change to TPM	Options analyzed	CBA approach	CBA result
2012 Issues Paper[1]			
Chapter 5 (*Proposed amendments to the TPM*) EA concerned that incentives existed for inefficient investment in transmission and new generation as a result of postage stamp charging and HVDC allocation to SI generation *2012 Issues Paper, [4.3.12]-[4.3.15]; [4.4.6]-[4.4.14].*Interconnection and HVDC charges not "market like" as do not involve granular allocation of costs of each transmission asset to beneficiaries (whereas connection charge does) *2012 Issues Paper, [5.2.6].* 2012 proposal: • Continuation of connection charge. *2012 Issues Paper, Section 5.4* • Removal of HVDC and interconnection charges. *2012 Issues Paper, Section 5.6* • Introduction of beneficiaries-pay (**BP**) charge (known as **SPD charge**) on load and generation to recover costs ofall new investments and 64 existing assets (including HVDC link). SPD charge uses wholesale market model to assess, after the real time dispatch of wholesale energy, the beneficiaries of each transmission asset in the previous half-hour. *2012 Issues Paper, [5.6.13]- [5.6.65]* • Residual charge allocated to generation and load (postage stamp charge allocated on basis of RCPD or RCPI). *2012 Issues Paper, [5.6.66]- [5.6.92]* • Continuation of prudent discount policy (**PDP**) with minor changes. Discount available where transmission customer can establish physical bypass is technically possible and commercially viable. *2012 Issues Paper[5.6.93]- [5.6.105]*	**Chapter 6 (*Evaluation of alternative means of achieving the objectives*).** **Qualitative analysis** of variety of options for reform on interconnection and HVDC charges based on DME Framework hierarchy. Five market-based/market-like charges rejected for lawfulness (merchant/vote-basedtransmission) or practicality (contract-based models) *2012 Issues Paper, [5.2.6]; Table 10*. EA then considered four variants of BP charging: the preferred SPD charge and options which assessed beneficiaries using (a) an economic model (b) flow tracing, and (c) zonal allocations *2012 Issues Paper, Section 6.5.* SPD charge was preferred over the other BP options as it was considered to be more accurate *2012 IssuesPaper, [5.6.63]- [5.6.65]*. No other pricing options were considered for primary charge because of DME Framework hierarchy *2012 Issues Paper, [5.2.1].* Residual charge also developed to recover the costs of remaining assets and the balance of Transpower's required revenues. Four options were assessed for residual charge: RCPD/RCPI on load/generation *2012 Issues Paper, [5.6.72]-[5.6.92]*, existing RCPD *2012 Issues Paper, [6.6.4]-[6.6.9]*, MWh charge *2012 IssuesPaper, [6.6.10]-[6.6.18]*, and incentive free MWh charge *2012 Issues Paper, [6.6.19]-[6.6.32]*. Preferred option was RCPD/RCPI on load/generation i.e. the charge would be levied on both demand (using RCPD) and generators (using RCPI), with 50% on generation *2012 Issues Paper, [5.6.72]- [5.6.78]*.	**Issues paper section5.7, Appendix F** Top-down quantitative assessment of benefits of preferred approach as primary focus, against a counterfactual of the status quo. Also quantitatively compares preferred approach against TPAG majority view (connection charge retained, postage stamp HVDC charge with 10-year transition,and no change to interconnection). *Appendix F, [1.1]-[3]* Efficiency benefits 0.3% of total marketrevenues. *AppendixF, [3.15]*	**Issues paper section 5.7, Appendix F** Net benefits $173.2M over 30 years. *2012 Issues Paper, Tables 7 and8; Appendix F, Table 3)*
Beneficiaries-Pay (BP) Working Paper			
Working paper explored other BP options - all using SPD method.	Four further BP charges considered: simplified version of the SPD charge, BP option based around GIT(GIT-plus-SPD option and SPD plus-GIT option) and zonal BP. *[1.8]; Chapter 6* Charge now applied to a smaller group of assets than the 2012 proposal (page 7). The direction of changewas a step towards simplification but EA still proposing using the SPD method to assess the deemed beneficiaries of each asset in every trading period at every node *[7.52]; [7.108(j)]*.	-	-

[1] Corrected CBA (AppendixF):

TPM Options Working Paper; Long Run Marginal Cost (LRMC) Working Paper: and Problem Definition Working Paper			
EA presented an updated definition of the problems with the current TPM (socialisation of transmission charges meant costs born by non-beneficiaries), *[1.19]-[1.30], TPM Options Working Paper*. (Its concerns now also included inefficient investment to avoid peak charges *[1.17], Problem Definition Working Paper* To address these issues the Authority developed **three packages of charges** without expressing a preference and two possible transition paths *[1.31]-[1.54], TPM Options Working Paper*. The flagship charge in all cases was a BP charge which used an economic model to forecast beneficiaries of each transmission asset. The charge was knownas Area of Benefit (**AoB**) charge but it actually allocated costs at nodes not within areas, *[1.42]- [1.44], TPM Options Working Paper*. Prior to this paper the EA had produced a working paper discussing LRMC charging. If found the practicality issues associated with LRMC charging problematic *[1.17]-[1.21], LRMC Working Paper*. These were said to include choosing the method, risks around forecasting demand and transmission investments, circumstances in which adjustments would be needed, deciding counterparties, and determining if the charges would be allocated on the basis of peaks or capacity. (NOTE: all of these issues also apply to the AoB charge, but for AoB charge they were not found to be problematic.)	Each package had a deeper definition of connection charge, a capacity based residual charge, and an AoB charge which was an ex ante assessment using economic models of the forecast beneficiaries of each transmission asset (base option) *[1.36]-[1.47], TPM Options Working Paper*. • One variant then added to the base option a surcharge based on LRMC which would signal the cost oftransmission investments in advance of those investments taking place. Once the investment was made it would be subject to AoB charge. *[1.48]-[1.51], TPM Options Working Paper* • The other variant added to the base option a SPD charge which would identify beneficiaries of individual transmission assets ex post using the SPD model on a three-year rolling average basis.*[1.52]- [1.54], TPM Options Working Paper* Two options (Applications A and B) for possible application of charges to new/existing assets were also offered for consultation, within each of the three packages. *[1.82]- [1.87]; Chapter 11, TPM Options Working Paper*	-	-
2016 Issues Paper; and 2017 Supplementary Consultation Paper			

Chapter 7 (*Proposed guidelines for Transpower to follow in developing a TPM*)
 	
In 2016 the EA presented an updated problem definition and its proposed solution. Amendments were made to theproposed solution in 2017. The 2016/17 proposal involved:
• Continuation of connection charge. *2016 Issues Paper, [7.13]-[7.27]*
• Removal of HVDC and interconnection charges. *2016 Issues Paper, [62]-[86]; Table 1*
• Introduction of AOB charge on load and generation to recover costs of all new investmentsand 11 pre-existing assets. Charges based on assessed lifetime benefits of each asset made under either a 'standard' or 'simplified' method (depending on type of investment). *2016 Issues Paper, [7.28]-[7.179]*
• Residual charge on load to cover costs of other existing assets and revenue shortfall. *2016 Issues Paper,[7.180]-[7.226]*
  ○ Initially this was allocated on customers' physical capacity (either transformer or line capacity in theprevious 12 months) or gross AMD (in the previous five years). *2016 Issues Paper, [7.181- 7.185].*
  ○ In 2017, the proposal was amended to provide for allocation of the residual charge based on AMD oranother method selected by Transpower which does not create any opportunities to avoid the charge.
• PDP was expanded significantly in 2016 to permit discounts where there was a material risk of plant closure but this element was then removed in 2017 amendment. *2016 Issues Paper, [7.227] -[260]; 2017 consultation paper,[74]-[80]*
• 2017 amendment also introduced a transitional price cap for some assets and transmission customers. *2017consultation paper, [85]-[97]*
	Chapter 9 (*Evaluation of alternative means of achieving the objectives*) and Appendix E (*Deeperconnection option considered by the Authority*)
	
	Quantitatively assessed two options: preferred AoB charge and deeper connection charge *[139] (2016 Issues Paper)*. The deeper connection charge involved the allocation of the costs of transmission assets to load and generation on the basis of flow shares *[E.9]-[E.10] (Appendix E, 2016 Issues Paper)*. The extent to which this charge would be applied would depend on the calculation of Herfindahl Hirshman indices (**HHIs**)(relating to shares of power flows to transmission customers), *2016 Issues Paper, [Exec Summary, 139(b)]*. Thus the charge would not apply to assets with an HHI of less than 2000, would apply in a graduated fashion to assets with a HHI of between 2000 and 7000 and would apply fully to assets with an HHI of more than 7000 *[4.1] (OGW report, 2016 Issues Paper)*. Deeper connection charge rejected on the basis of its application of the DME framework and practicality threshold (identification of asset boundaries and beneficiaries complex) *2016 Issues Paper, [9.15(c)]*.
	
	High-level qualitative assessment of varied status quo (including incremental reform) *2016 Issues Paper, [9.3]*, tilted postage stamp *2016 Issues Paper, [9.28]-[9.34]*, and Transpower's broad-based low rate charge[9.42]-[9.48] (*2016 Issues Paper*). These were all rejected because they would not promote efficient investment or promote durability (spread costs, does not charge according to benefits) *[9.34]; [9.39]-[9.41]; [9.47]-[9.48], 2016 Issues Paper*. In addition a LRMC-based tilted postage stamp was rejected because of reliance on accuracy of future demand and transmission investment forecasts *2016 Issues Paper, [9.34(b)]*,and a capped SPD charge was rejected because of its potential to distort bids and offers in the wholesale market *2016 Issues Paper, [9.39]*.
		Chapter 8 and Appendix C
		
		CBA for AoB charge (EA's proposal) and deeper connection charge options, against status quo Table 4. *2016 Issues Paper, [8.50]-[8.54]*
		
		Other options rejected on qualitative assessment.
			Chapter 8 and Appendix C
			
			Net benefits of $213M [8.48]. *2016 Issues Paper, Table1 (OGW report)*

2019 Issues Paper[2]; and 2020 Supplementary Consultation Paper			
Issues Paper, Chapter 3 (*Overview of the proposal*) and Appendix B Problem statements reprioritized with the main focus now the (alleged) inefficient investment to avoid peak charges.2019/20 proposal involved: • Continuation of connection charge. *2019 Issues Paper, Table 2; [B.23]-[B.35]* • Removal of HVDC and interconnection charges. *2019 Issues Paper, [3.3]* • Introduction of BP charge (known as benefit-based charge [**BB charge -** AoB charge renamed] on load and generation to recover costs of all new investments and seven pre-existing assets). Charges based on assessedlifetime benefits of each asset made under either a 'standard' or 'simplified' method (depending on type of investment). *2019 Issues Paper, [3.3(a)]; [B.36]-[B.193]* • Residual charge on load to cover costs of other existing assets and revenue shortfall. Allocated on customershistoric gross anytime maximum demand. Amended in 2020 to provide for allocation to be updated regularly based on changes in usage with a lag. *2019 Issues Paper, [3.3(b)]; [B.194]-[B.231]; 2020 supplementary consultation, Chapter 5* • PDP expanded to also provide for discount where standalone costs of supply is lower than transmission charges(example given was Tiwai point). The PDP is wider than status quo but not as wide as first 2016 proposal. *2019 Issues Paper, [4.147]-[4.153] and [B.249]-[B.258]; 2020 supplementary consultation, Chapter 6* Price cap for some assets and transmission customers. *2019 Issues Paper, [B.260]-[B.286]*	**Issues Paper, Appendix E (*Assessment of alternatives*)** Quantitatively assessed the proposal and an alternative which replaced the RCPD with a broad based MWhcharge *2019 Issues Paper, [4.4] Table 4*. The 2019/20 proposal was said to provide superior benefits from more efficient grid use and more efficient investment from Distributed Energy resources (**DER**)(such as grid scale batteries), generation and load as well improved scrutiny of grid investment and increased investor certainty *2019 Issues Paper, Tables 4 and 5*. In contrast the alternative only provided benefits from increased grid use and less inefficient investment (in DER) to avoid peaks. Qualitatively assessed other options *2019 Issues Paper, [E.2]*: ▪ **Simplified staged approach** proposed by Transpower which would include staged adoption of: simplified BB charge recovered as a peak charge which was LRMC like, retained HVDC charge, fixed residual charge. This was rejected as there was insufficient alignment between beneficiares and costsof individual assets. *2019 Issues Paper, [E.104]-[E.119]* ▪ **Deeper connection charge** rejected for largely same reasons as 2016. *2019 Issues Paper, [E.120]-[E.124]* ▪ **Tilted (regional) postage stamp** rejected as it does not align transmission charges with costs ofindividual transmission investments. *2019 Issues Paper, [E.125]-[E.130]* Other options also listed (TPAG, 2012 Issues Paper, Beneficiaries-Pay Working Paper, LRMC WorkingPaper, 2016 Issues paper) but the EA said *"[o]n further consideration we have not changed our assessment of these options discussed in our earlier papers". 2019 Issues Paper, [E.131]-[E.132]*	**Chapter 4** Quantitative CBA of proposal and alternative) using a series of bespoke models. *2019 Issues Paper, Table 4* Other options rejectedon qualitative assessment *2019 Issues Paper, [E.131]-[E.132]*	**Chapter 4** Net benefits of $2,711M. Table 4, 2019 Issues Paper Compared to 2016 CBA, addition of new category of benefit (increase in consumer surplus – benefits of $2,579M). *2019 Issues Paper, Table4*
Response to Feedback on the 2019 Cost Benefit Analysis Paper			
		Quantitative comparison of proposal to three other policy scenarios: "alternative"; future only; and HVDC only *Page ii*	Net benefits of $1,335 M 2020 *Supplementary consultation paper, pages I and ii, Table 3 page 5.*
June 2020 Decision on TPM Guidelines[3]			

[2] 2019 CBA technical paper
[3] 2020 CBA Technical Paper

Decision, Chapters 6-14	**Decision, Appendix B (*Alternatives put forward in submissions*)**	**Decision, Chapter 15; CBA technical paper**	**Decision, Chapter 15; CBA technical paper**
2020 Decision involved: • Continuation of connection charge. *Decision, [1.4], Table 1 and Chapter 8* • Removal of HVDC and interconnection charges. *Decision, Page i* • Introduction of BP charge on load and generation to recover costs of all new investments and 7 pre-existing assets. Charges based on assesed lifetime benefits of each asset made under either a 'standard' or 'simplified'method (depending on type of investment). *Decision, Chapter 9* • Residual charge on load to cover costs of other existing assets and revenue shortfall. Allocated on customershistoric gross anytime maximum demand updated regularly based on changes in usage with a lag. *Decision,Chapter 10* • PDP expanded from status quo to also provide for discount where standalone costs of supply is lower thantransmission charges. *Decision Chapter 12* • Price cap for some assets and transmission customers. *Decision, Chapter 13*	Quantitative analysis of the benefits expected from the 2019 proposal compared to (*CBA technical paper,Table 1*): (a) Option where HVDC was retained but the RCPD signal weakened so it effectively became a perMWh charge *CBA technical paper, [2.227]* (b) Option where only future investments covered by BB charge *CBA technical paper, [2.228]-[2.229]* (c) Option where only future investments plus HVDC charge covered by BB charge *CBA technicalpaper, [2.230],* 6 alternative options considered qualitatively *Decision [B.4]-[B.62]*: • RCPD charge with a weakened price signal rejected because it would not be a complete solution toproblems ie improve long term supply efficiency *Decision, [B.7]]-[B.18]* • tilted postage stamp charge rejected as it did not sufficiently align benefits with costs *Decision, [B.19]-[B.31]* • deeper connection charge rejected for same reasons as in *2019 Decision, [B.32]-[B.42]* • regional approach, was rejected as it did not sufficiently align benefits with costs *Decision, [B.43]-[B.52]* Transpower's options for incremental TPM reform, and Trustpower's most practicable options were both rejected as likely to result in less benefits than the proposal. *Decision,[B.53]-[B.58]*	Primarily bottom-up; some top-down analysis. *CBA technical paper, Table1* Quantitative analysis where possible, of 3 options; weakened RCPD, 'future-only' option and 'HVDC-only' option. *CBA technical paper, Tables 1 and 3*	Net benefits of $1,335M *Decision, [15.3] and Table 2*

Review of the cost benefit analysis of the transmission pricing methodology

A report for Trustpower

2 December 2021

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1. Introduction

The Electricity Authority (the Authority) is consulting on its proposed new transmission pricing methodology (TPM). The TPM determines how the costs of Transpower's electricity transmission grid are recovered from transmission customers.

The proposed TPM would replace the current TPM. This would result in substantial changes to transmission pricing, including most prominently:

- the discontinuation of two existing transmission charges, being:
  - the HVDC charge, under which the costs of the Cook Strait interconnector are recovered from South Island generators in proportion to their South Island mean injection (SIMI) over five years; and
  - the interconnection charge, under which interconnection costs (excluding those recovered by the HVDC charge) are recovered from load customers in proportion to their contribution to regional coincident peak demand (RCPD);
- the establishment of two new transmission charges, being:
  - the benefit-based charge, under which the costs of seven historical investments and new grid investments are recovered from load and generation customers in proportion to their calculated share of net private benefits;[1] and
  - the residual charge, under which interconnection costs that are not recovered through benefit-based charges are recovered from load customers in proportion to their anytime maximum demand between from 1 July 2014 to 30 June 2018 (or for the first four years for a new customer) and updated to reflect changing average energy usage over an historical period between eight and five years prior to each pricing period.[2]

1.1 The Authority's New CBA

Alongside its proposed TPM, the Authority has published a cost benefit analysis (CBA), which estimates that the net benefits of its proposal would be $1.25 billion in present value terms, within a range of $0.4 to $2.9 billion.[3]

This is not the first CBA that the Authority has prepared in connection with transmission pricing. Between 2011 and 2020, the Authority consulted on the guidelines that apply to Transpower's development of the TPM. During this consultation process, the Authority proposed changes to the TPM guidelines and prepared (or commissioned) CBAs in connection with these proposals, including:

- a CBA of the proposed TPM guidelines set out in its 2012 issues paper, which found net benefits of $173.2 million;[4]
- a CBA of the proposed TPM guidelines set out in its 2016 issues paper, which found net benefits of $213.3 million;[5]

[1] Electricity Authority, *Proposed transmission pricing methodology*, 8 October 2021, para 43(1).

[2] Electricity Authority, *Proposed transmission pricing methodology*, 8 October 2021, paras 70-72.

[3] Electricity Authority, *Proposed transmission pricing methodology*, Consultation paper, 8 October 2021, para 14.9.

[4] Electricity Authority, *Transmission pricing methodology: issues and proposal*, Consultation paper, 10 October 2012, p F4.

[5] Oakley Greenwood, *Cost benefit analysis of transmission pricing options*, 11 May 2016, p 62.

- a CBA of the proposed TPM guidelines set out in its 2016 supplementary issues paper, which found net benefits of $203.0 million;[6]
- a CBA of the proposed TPM guidelines set out in its 2019 issues paper (the 2019 CBA), which found net benefits of $2,711 million;[7] and
- a CBA of the proposed TPM guidelines set out in its 2020 decision paper (the Revised CBA), which found net benefits of $1,335 million.[8]

Each of these CBAs were prepared in connection with proposals to introduce guidelines that would require transmission charges to be calculated on beneficiary pays principles, although the form of the charge proposed in 2012 was very different to those proposed from 2016.

The CBA that the Authority has prepared for its proposed TPM is similar in structure and approach to the 2019 CBA and the subsequent Revised CBA published alongside its decision paper. Although the overall net benefit estimates are similar to those estimated in the Revised CBA, the components that underpin this result are quite different, as indicated in table 1.1 below. Further, the Authority has changed the basis on which it reports results, from a median approach to a probability weighted mean.

Table 1.1: Comparison of results between Revised CBA and New CBA ($ million)

Category of benefits	Revised CBA (10 June 2020) Median	New CBA (8 October 2021) Probability weighted mean
Net change in consumer welfare	1,131	1,098
Gross change in consumer welfare	*715*	*2,303*
Transfers from consumers to generators	*416*	*-1,205*
Less efficient battery investment	51	55
Transmission benefits brought forward	95	243
Transmission costs brought forward	-35	-281
More efficient investment	40	106
Increased scrutiny of investment	49	47
Increased investor certainty	31	11
Net benefit	**1,335**	**1,253**

Source: Electricity Authority

1.2 Concerns that we have previously raised

We previously prepared advice for Trustpower in respect of the 2019 and Revised CBAs, including:

- a report reviewing the 2019 CBA;[9]
- a memorandum reviewing submissions that commented on the substance of the 2019 CBA;[10]

[6] Electricity Authority, *Transmission pricing methodology: second issues paper*, Supplementary consultation, 13 December 2016, para 118.

[7] Electricity Authority, *2019 issues paper transmission pricing review*, Consultation paper, 23 July 2019, p 21.

[8] Electricity Authority, *Transmission pricing methodology 2020 guidelines and process for development of a proposed TPM*, Decision, 10 June 2020, p 92.

[9] HoustonKemp, *Review of the cost benefit and options analysis of the EA's proposed TPM guidelines*, 30 September 2019.

[10] HoustonKemp, *Submissions on the cost benefit analysis of the Electricity Authority's proposed transmission pricing methodology guidelines*, 30 October 2019.

- a memorandum reviewing the Revised CBA;[11] and
- a memorandum reviewing the technical paper for the Revised CBA.[12]

Throughout our reviews of the 2019 and Revised CBAs, we raised material concerns about the reliability of the estimates of net benefits prepared by the Authority, stemming from concerns about the assumptions and approaches that underpinned them. These concerns include that the Authority:

- incorrectly included in its analysis benefits that arose through transfers of value between generators and consumers, which create benefits for one party by imposing costs on another, and therefore do not increase net benefits;
- incorrectly excluded from its analysis costs that its modelling shows would be incurred by generators and distributors to meet increases in demand under its proposal; and
- estimated benefits from investment efficiencies by:
  - assuming what it set out to show, ie, that its proposal would deliver more efficient outcomes than the status quo; and
  - estimating the magnitude of these efficiency benefits using assumptions of fact that were not supported by any reliable evidence.

1.3 Scope and findings of this report

Trustpower has asked us to review the New CBA and to:

- identify whether the Authority has made any changes in the assumptions or methods underpinning its CBA since the Revised CBA; and
- provide our opinion as to whether these changes affect the opinion that we have previously expressed about the reliability of the Authority's CBAs.

Our review of the New CBA indicates that, although the broad structure of the CBA remains the same as the Revised CBA, and the headline result looks similar, the New CBA is substantially different from the Revised CBA. The Authority has made important changes to the options assessment and the modelling assumptions that underpin the grid use modelling in the New CBA. These changes have consequences for the results of the CBA.

In terms of the structure of the CBA, we note that although the Authority has undertaken a limited options analysis, the benefits of its proposed TPM are over $1 billion less than the benefits of an alternative TPM in which load customers pay for 75 per cent of investments allocated under the simple approach. If differences of this magnitude do not provide the Authority comfort that there is a sound empirical basis to adopt this alternative option, then it raises questions as to whether the Authority's reliance on its CBA in support of its proposed TPM is reasonable.

The Authority has changed its assumptions about load customers' response to its proposed charges. The effect of these changes is that in the New CBA, load customers perceive the proposed TPM as giving rise to lower electricity prices and respond with higher consumption, which in turn raises wholesale prices for generators. The magnitude of these price changes is substantial and the Authority should consider the plausibility of these results.

Due to its material implications, this changed assumption by itself largely explains why the Authority estimates positive net benefits in its CBA. However, the changing assumptions also gives rise to concerns because:

[11] HoustonKemp, *Review of the Electricity Authority's revised cost benefit analysis*, 18 May 2020.

[12] HoustonKemp, *Review of the Electricity Authority's cost benefit analysis technical paper*, 13 July 2020.

- there appear to be no changed circumstances that could explain why the Authority has changed these assumptions; and
- the reliability of the changed assumptions is open to significant question since there is little reason to expect that benefit-based charges will remain fixed in the long run as the Authority assumes.

The Authority has also changed its approach to estimating consumer surplus and producer surplus. Overall, we consider that these changes represent a step in the right direction, correcting errors that the Authority has previously made. However, we remain concerned that its new approach to estimating the change in consumer surplus largely relies on a single parameter – maximum price – that the Authority selects without a solid empirical basis.

Finally, we note that the Authority continues to incorrectly exclude the increased costs that higher peak demand under its proposed TPM would impose on the generation and distribution sectors of the electricity industry from its estimates of net benefits. These amount to a further $435 million and $211 million of costs, respectively, that the Authority has not included in its assessment of costs and benefits.

There are a number of aspects of the New CBA on which we have not offered an opinion. This is largely because our review has been focused on those aspects of the CBA which have changed since the Revised CBA. Unless otherwise stated in this document, our opinion about other aspects of the New CBA has not changed.

Overall, although we note that the Authority has made a number of positive changes to its CBA, there remain important concerns with the CBA that affect its reliability and warrant further review by the Authority.

1.4 Structure of this report

The remainder of this report is structured as follows:

- section 2 briefly recaps essential features of a CBA and explains that the Authority's options analysis in its New CBA does not select the option with the highest net benefits;
- section 3 sets out the broader context for the Authority's New CBA and summarises the changes in the electricity market that it projects would be caused by the proposed TPM;
- section 4 discusses modelling assumptions that the Authority has revised in the New CBA that have the effect of materially increasing forecast consumption and net benefits under its proposed TPM;
- section 5 introduces a new approach that the Authority has used to estimate the change in consumer surplus in its New CBA and the challenges with this approach;
- section 6 describes changes that the Authority has made to its calculation of producer surplus to correct an error in its approach;
- section 7 explains that under the assumptions of the New CBA, wealth transfers are likely to be less important to net benefits and there is insufficient information with which to estimate the magnitude of these transfers; and
- section 8 notes that the Authority's calculation net benefits does not incorporate increases in the costs of serving higher peak demand, including increased generation and distribution costs.

2. Approach to applying CBA

We previously criticised the Authority's 2019 and Revised CBAs as not being consistent with best practice applications of CBA. In particular, we criticised:[13]

- the limited exploration of alternative options against which the proposed TPM guidelines were assessed; and
- the Authority's assumptions that its proposal was efficient and would therefore give rise to net benefits.

In this section, we briefly outline best practice application of CBA and how this relates to the options analysis undertaken by the Authority in its New CBA, which is different from the options analysis undertaken in the Revised CBA. Although the Authority continues to make assumptions that its proposal is efficient, we do not revisit this issue in this report since the substance of our concerns has not changed since the Revised CBA.

2.1 Best practice application of CBA

Options analysis is a key feature of any CBA and allows for the selection of the best policy or regulation. For example, New Zealand Treasury's guide to social cost benefit analysis describes the policy development process as set out in figure 2.1 below, in which an options analysis is described as the second step.

Figure 2.1: The policy development process

Source: New Zealand Treasury, Guide to social cost benefit analysis, July 2015, p 8.

Similar principles are applied in Australia, as described in the Council of Australian Governments' (COAG's) guide to best practice regulation, which commences with:[14]

- establishing a case for action before addressing a problem;
- considering a range of feasible policy options, including self-regulatory, co-regulatory and non-regulatory approaches, and assessing their benefits and costs; and
- adopting the option that generates the greatest net benefit for the community.

Although there are variations in how different authorities break down the steps involved in a CBA, the principal tasks involved are consistent, and include each of the elements set out in section 39(2) of the Electricity Industry Act. We describe each of the steps in more detail below.

[13] HoustonKemp, *Review of the cost benefit and options analysis of the EA's proposed TPM guidelines*, 30 September 2019, pp 75-84.

[14] Council of Australian governments, *Best practice regulation: a guide for ministerial councils and national standard setting bodies*, October 2007, p 4.

2.1.1 Step 1: identification of the problem

In the development of any policy or regulation, the first stage is the clarification of a problem or opportunity to which a proposed change is responding. There is often a further requirement that the problem or opportunity has some degree of materiality, to justify action.[15]

Consistent with a materiality hurdle, best practice entails a presumption against new or increased regulation.[16] Any change to policy or regulation gives rise to costs, even if these relate only to the administration of the change. It follows that a necessary condition for the pursuit of change is the identification of a problem or opportunity, and therefore the potential for benefits, to offset these costs.

2.1.2 Step 2: specification of options to address the problem or opportunity

Once the need for action is determined, the second stage is the specification of possible policies, projects or solutions that respond to the problem or opportunity.

A best practice approach is to assess several feasible means of responding to the problem or opportunity. The alternatives to be assessed in a CBA should include the best from an economic perspective.[17]

It is not necessary that all possible alternative options be considered in a CBA. A reasonable balance between rigour and the limits of analytical capacity can be struck through elimination of alternatives using preliminary analysis, leaving a manageable number of alternative options to address the problem.

2.1.3 Step 3: evaluate the benefits and costs of each option

The third stage is the evaluation of the policies, projects or solutions. This broad description captures a number of further steps, which may include:

- identification of the parties that are affected, and the potential benefits and costs of the policies, projects or solutions;
- quantification of these benefits and costs in comparable dollar terms; and
- assessment of the sensitivity of the results to assumptions and/or other matters that are not capable of quantification.

Although this third stage is sometimes referred to as a CBA,[18] a CBA in some contexts is understood to refer collectively to all three of these stages – for example by the Authority itself, in its 2013 CBA working paper.[19]

2.2 Options analysis in the New CBA

Notwithstanding the general description of a CBA as being a tool to identify and select the best option, the Authority's proposed TPM is not identified by its New CBA as being the best option.

In the New CBA, the Authority contemplates only options that comply with the TPM guidelines. The options that the Authority assesses include:

- its 'central' scenario, in which:

[15] See for example: United States Office of Management and Budget, *Regulatory analysis*, Circular A-4, 17 September 2003, p 4.

[16] Council of Australian governments, *Best practice regulation: a guide for ministerial councils and national standard setting bodies*, October 2007, p 4

[17] New Zealand Treasury, *Guide to social cost benefit analysis*, July 2015, p 9.

[18] For example, New Zealand Treasury identifies the policy evaluation step as a 'CBA' – see New Zealand Treasury, *Guide to social cost benefit analysis*, July 2015, p 8.

[19] Electricity Authority, *Transmission pricing methodology: CBA*, Working paper, 3 September 2013, table 4, pp 10-12.

  - generators are allocated a 50 per cent share of costs under the simple method for determining benefit-based charges;[20] and
  - overhead opex is recovered in benefit-based charges;[21]
- a '75/25' scenario, in which load is allocated a 75 per cent share of costs under the simple method and generators 25 per cent; and
- an 'overhead opex in residual charge' scenario, in which overhead opex is recovered in the residual charge, rather than the benefit-based charge.

The Authority estimates present value net benefits of its proposal under the 'central' scenario as being $1,253 million, falling within a range from $365 million to $2,918 million. However, it finds greater net benefits under its alternative options, ie:[22]

- under the '75/25' scenario, the Authority estimates present value net benefits of $2,377 million, falling within a range from $713 million to $3,465 million; and
- under the 'overhead opex in residual charge' scenario, the Authority estimates present value net benefits of $1,574 million, falling within a range from $447 million to $2,901 million.

The Authority explains that it does not prefer these alternatives, notwithstanding the results of its CBA, which indicate that they both perform better than its proposal. The Authority explains that:

- it does not have strong enough evidence to move away from a 50:50 allocation of costs under the simple method and that it will be able to revisit this assumption in five years' time with more evidence;[23] and
- for most sensitivities, there is very little difference in net benefits as between recovering overhead opex in the benefit-based charge or the residual charge and further it finds that the weighted average difference of $321 million is *'very much influenced by sensitivities, especially at the low end of the distribution'*.[24]

We understand that quantitative evidence of benefits cannot always be reliably undertaken and that the Authority must sometimes apply judgement in considering qualitative factors.

In these circumstances, the Authority has applied its CBA to produce quantified estimates of net benefits for each of the options. The net benefits of alternative options are materially higher than the Authority's proposed option – by $1,124 million under the '75/25' scenario and by $321 million under the 'overhead opex in residual charge' scenario.

These net benefits do not appear to be negligible. When considered against the Authority's determination to proceed with its TPM guidelines on the basis of net benefits of $1,335 million in its Revised CBA,[25] or the much smaller net benefits of $213 million in the Oakley Greenwood CBA,[26] it appears surprising that the Authority does not consider the prospect of $1,124 million of additional present value net benefits to be 'strong evidence' supporting the adoption of the policy modelled in the '75/25' scenario.

[20] Electricity Authority, *Proposed transmission pricing methodology*, Consultation paper, 8 October 2021, para 5.35.

[21] Electricity Authority, *Proposed transmission pricing methodology*, Consultation paper, 8 October 2021, para 6.5.

[22] Electricity Authority, *Proposed transmission pricing methodology*, Consultation paper, 8 October 2021, table 13, p 128.

[23] Electricity Authority, *Proposed transmission pricing methodology*, Consultation paper, 8 October 2021, paras 5.35-5.39.

[24] Electricity Authority, *Proposed transmission pricing methodology*, Consultation paper, 8 October 2021, paras 6.12-6.13.

[25] Electricity Authority, *Transmission pricing methodology 2020 guidelines and process for development of a proposed TPM*, Decision, 10 June 2020, table 2, p 92.

[26] Oakley Greenwood, *Cost benefit analysis of transmission pricing options*, 11 May 2016, table 12, p 62.

In support of this position, the Authority cites 'limitations' of its CBA, the fact that the CBA is only one factor that influences its decision and the fact that new evidence will become available over the next five years to better inform decision-making.[27]

We agree that that the Authority's CBA has substantial limitations – some of our concerns about the New CBA are set out in the remainder of this report. However, Authority does not consider these limitations to be such that it cannot rely upon the quantified outcomes of its CBA.

We disagree that the CBA should be only one factor in the Authority's decision-making. The purpose of CBA is to lend rigour to decision-making by placing a framework around it that requires the decision-maker to make decisions on the basis of evidence. That is, the CBA should be the framework for the Authority's decision-making process, and should incorporate (either quantitatively or qualitatively) the factors that the Authority considers relevant to its objective. The relegation of the CBA to just one of several factors to which the Authority may have regard does not appear to be consistent with this standard of evidence-based decision-making.

Finally, we agree with the Authority that a lack of clear evidence supporting an option should weigh against the selection of that option. However, the lack of evidence about the effects of the 75/25 option is not unique to that option – the New CBA contains many strong assumptions about how the Authority's proposed TPM will change market outcomes for which there are little or no evidence. The 2019 and Revised CBAs also contained many such assumptions of the proposed TPM guidelines. The standard of evidence that the Authority requires in order to select the 75/25 option as its preferred implementation of the TPM appears wholly inconsistent with its current and previous approaches to CBA.

[27] Electricity Authority, *Proposed transmission pricing methodology*, Consultation paper, 8 October 2021, para 5.38.

3. Changes to the electricity market context

Although it produces an overall net benefit estimate that is broadly consistent with the Revised CBA, the New CBA arrives at this estimate using very different assumptions, which in turn gives rise to different results.

In this section, we set out the broader market context assumed for and predicted by the Authority's grid use modelling. Specifically, we note that:

- the Authority assumes much stronger demand growth in the New CBA relative to the Revised CBA;
- consistent with the demand growth assumptions, the amount of generation investment forecast in the New CBA is vastly greater than in the Revised CBA; and
- the Authority finds that although consumers pay lower prices for electricity as a result of its proposed TPM, at the same time generators receive higher prices.

These results are set out further below.

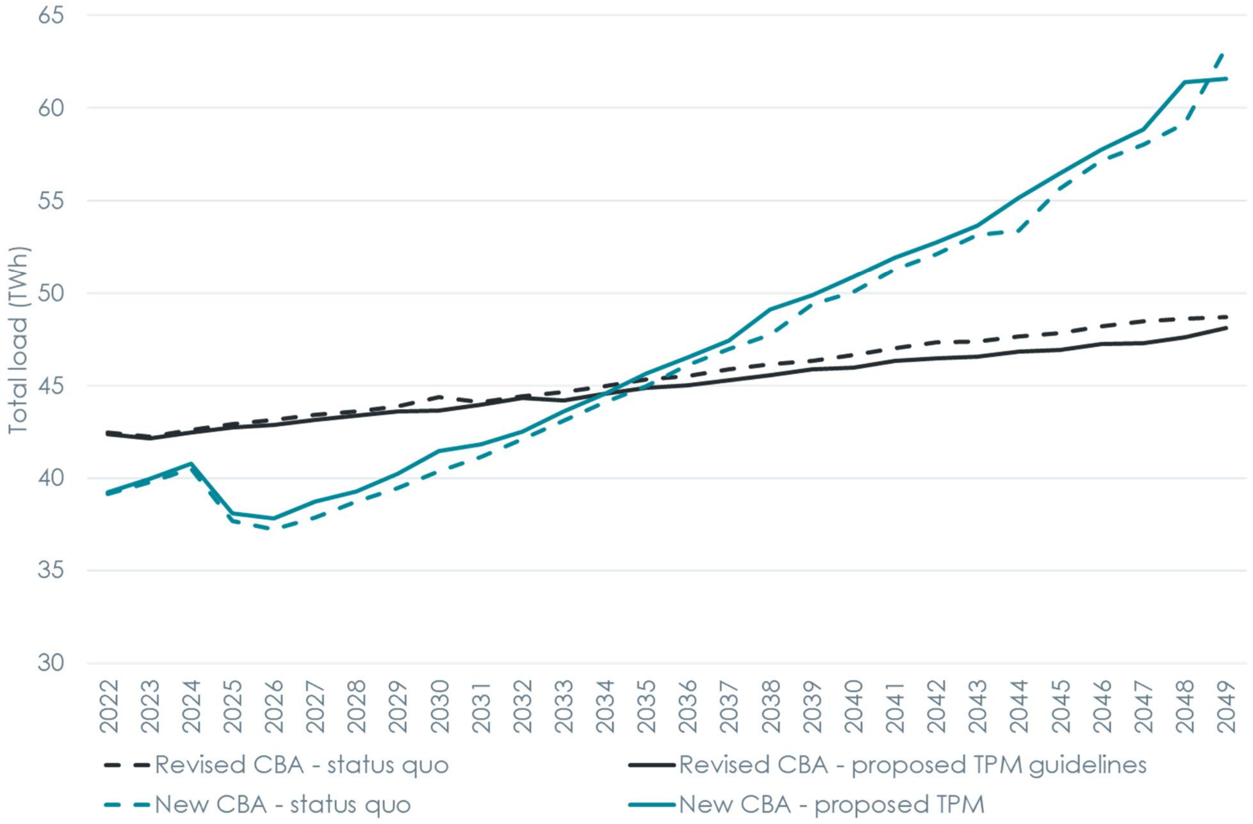
3.1 Demand is assumed to grow much faster

The Authority has sourced new demand assumptions from the Climate Change Commission for its New CBA. Under these assumptions, total consumption grows at about 1.7 per cent per year between 2022 and 2049 in the New CBA, whereas it grew by only 0.5 per cent per year in the Revised CBA.

This difference is substantial, meaning that by 2049, total consumption assumed by the Authority in the New CBA is almost 30 per cent higher than under the Revised CBA. This occurs even though the New CBA assumes initially lower consumption (including due to the exit of the Tiwai Point smelter in 2024) such that total consumption under the New CBA only becomes higher than under the Revised CBA in 2035.

We show the changed consumption assumptions in figure 3.1 below, for the central scenario with baseline assumptions.

Figure 3.1: Total consumption grows much faster in the New CBA than the Revised CBA



Source: Electricity Authority worksheets 'total_load.csv'

3.2 Investment in generation surges

Due predominantly to the much higher demand growth assumptions in the New CBA, the amount of forecast generation investment is far greater than the Authority predicted in the Revised CBA.

In the Revised CBA, the Authority's central scenario with baseline assumptions found that over the period from 2022 to 2049:[28]

- under the status quo, 11 new generation plants would be built at a total present value cost of $1.88 billion; and
- under the proposed TPM guidelines, 11 generation plants would be built at a total present value cost of $1.76 billion.

This information is summarised for the median sensitivity at table 3.1 below.

By contrast, in the New CBA, the Authority's central scenario with baseline assumptions finds that over the period from 2022 to 2049:[29]

[28] Electricity Authority, *plant_investment.csv* and *generation_investment.csv*, 17 April 2020, available online at https://emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis/2020/20200417_TPM_CBAfilesToSupportApr2020InformationPaper/Grid%20use%20model/Output/Central.

[29] Electricity Authority, *plant_investment.csv* and *generation_investment.csv*, 20 October 2021, available online at https://emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis/2021/20211020_CBAforProposedNewTPM/Grid%20use%20model/Output/Central.

- under the status quo, 70 new generation plants would be built at a total present value cost of $7.12 billion.
- under the proposed TPM, 68 generation plants would be built at a total present value cost of $7.40 billion.

Unlike in the Revised CBA, in which at most two generators were assumed to be built in any year, in the New CBA multiple generators are built each year – as many as 13 in 2049 under the status quo. The updated table is set out at table 3.2 below, showing the path of investment in generation plant in the central scenario under baseline assumptions.

Table 3.1: Investment in generation plant in the Revised CBA median scenario, 2022 - 2049

Model year	Status quo		Proposed TPM	
	Plant name	Investment ($ million)	Plant name	Investment ($ million)
2022	-	-	-	-
2023	-	-	-	-
2024	-	-	-	-
2025	LakePukaki (hydro)	113.4	LakePukaki (hydro)	113.4
2026	-	-	-	-
2027	-	-	Wairau (hydro)	291.8
2028	-	-	-	-
2029	NorthBT (hydro)	1,059.3	NorthBT (hydro)	1,059.3
	-	-	Coleridge2 (hydro)	292.0
2030	-	-	-	-
2031	-	-	-	-
2032	-	-	-	-
2033	-	-	-	-
2034	-	-	-	-
2035	Wairau (hydro)	291.8	HawkesBayW (wind)	593.1
2036	Coleridge2 (hydro)	292.0	-	-
	HawkesBayW (wind)	593.1	-	
2037	-	-	-	-
2038	-	-	Mahinerangi2	433.4
2039	GWindL1_s1 (wind)	684.5	-	-
2040	-	-	-	-
2041	-	-	CastleHill_s1	547.6
2042	CastleHill_s1	547.6	-	-
2043	-	-	CastleHill_s2	547.7
2044	-	-	CastleHill_s3	547.8
2045	GWindL1_s2 (wind)	684.6	-	-
2046	-	-	-	-
2047	-	-	GWindL1_s1 (wind)	684.5
2048	CastleHill_s2	547.7	-	-
2049	-	-	-	-

Source: Calculated by HoustonKemp using data from s_1.0_1.05_0.01_0.9plant_investment.csv

Table 3.2: Investment in generation plant in the New CBA central scenario, 2022 - 2049

Model year	Status quo		Proposed TPM	
	Plant name	Investment ($ million)	Plant name	Investment ($ million)
2022	Turitea_s1	305.6	Turitea_s1	305.6
2023	Turitea_s2	264.5	Turitea_s2	264.5
	Cass	173.1	Cass	173.1
2024	-	-	-	-
2025	HawkesBayW	329.0	HawkesBayW	329.0
	GGeoTau2	573.7	GGeoTau2	573.7
2026	-	-	-	-
2027	-	-	GWindR40_1	143.2
	-	-	GWindR40_22	233.7
	-	-	GWindR40_77	277.2
2028	GWindR40_1	143.2	GWindR40_16_B	180.4
	GWindR40_16	144.1	-	-
	GWindR40_22	233.7	-	-
	GWindR40_77	277.2	-	-
2029	-	-	CastleHill_s1	326.7
2030	CastleHill_s1	326.7	CastleHill_s2_B	423.7
	CastleHill_s2	326.7	CastleHill_s2	326.8
	-	-	CastleHill_s3_B	423.8
2031	Mohikin	322.0	Mohikin	322.0
2032	Hauaurumaraki_s1	411.7	-	-
2033	Hauaurumaraki_s2_B	533.8	TasmnSolGeneric1_B	301.0
	-	-	GWindS7_B	126.1
2034	CastleHill_s3_B	423.8	BOPSolGeneric1_B	292.2
	TasmnSolGeneric1_B	301.0	Hauaurumaraki_s1	411.7
	-	-	MarlSolGeneric1_B	152.6
	-	-	MarlSolGeneric2_B	219.2
2035	WstWktoSolGeneric1	197.0	Hauaurumaraki_s2_B	533.8
	BOPSolGeneric1	195.2	GWindR40_48_B	231.0
	-	-	GWindR40_82_B	241.1
2036	MarlSolGeneric1_B	152.6	GWindL1_s1_B	529.5
	MarlSolGeneric2_B	219.2	-	-
	GWindS7_B	126.1	-	-
	HwkBySolGeneric1_B	265.9	-	-
2037	SthCantSolGeneric2_B	284.6	GWindM2	350.4
	SthCantSolGeneric3_B	285.3	-	-
	GWindL1_s1	408.4	-	-
	GWindM2	350.4	-	-
	NthWaikatoSol_B	433.9	-	-
	CantSolGeneric1_B	296.7	-	-
2038	-	-	WstWktoSolGeneric1_B	293.9

Model year	Status quo		Proposed TPM	
	Plant name	Investment ($ million)	Plant name	Investment ($ million)
	-	-	CentralWind_B	268.4
	-	-	HwkBySolGeneric1_B	265.9
	-	-	GWindL1_s2_B	529.6
	-	-	StocktonMine	139.5
	-	-	Awhitu_B	45.4
2039	SthCantSolGeneric1_B	278.8	Puketoi	278.5
	SthCantSolGeneric4_B	278.9	Waitohora	273.3
	GWindL1_s2_B	529.6	-	-
	GWindR40_48_B	231.0	-	-
	GWindR40_82_B	241.1	-	-
	CenOtgoSolGeneric1_B	284.4	-	-
2040	-	-	GWindM4_B	447.3
	-	-	Stockton	107.5
2041	Puketoi	278.5	GWindM3	350.4
	Waitohora	273.3	-	-
2042	StocktonMine	139.5	Taharoa_B	136.1
	-	-	Taumata_B	110.9
	-	-	CantSolGeneric1_B	296.7
2043	Taharoa	110.0	SthCantSolGeneric2_B	284.6
	Taumata	89.6	SthCantSolGeneric3_B	285.3
	CentralWind	210.2	GWindM1	350.4
2044	Awhitu_B	45.4	GWindS3_B	126.1
	-	-	NthWaikatoSol_B	433.9
	-	-	SthCantSolGeneric1_B	278.8
	-	-	SthCantSolGeneric4_B	278.9
	-	-	GWindS1_B	151.3
	-	-	Hurunui_B	196.6
	-	-	Wairau	304.6
2045	GWindM1	350.4	Mahinerangi2	258.6
	GWindM3	350.4	GWindR40_12	276.4
	GWindS3	101.8	CenOtgoSolGeneric1_B	284.4
	GWindM4	350.4	-	-
	GWindR40_42	240.7	-	-
2046	GWindS1_B	151.3	GWindL2_s1	408.4
	LongGul_B	32.6	-	-
	Hurunui_B	196.6	-	-
	Stockton	107.5	-	-
	Wairau	304.6	-	-
	Mahinerangi2_B	338.0	-	-
	GWindR40_12_B	349.1	-	-
	GWindR40_13_B	168.1	-	-
2047	HaweaCG	42.9	HaweaCG	42.9

Model year	Status quo		Proposed TPM	
	Plant name	Investment ($ million)	Plant name	Investment ($ million)
	GWindL2_s1	408.4	GWindL2_s2	408.5
	GWindL2_s2	408.5	-	-
2048	-	-	GWindR40_42_B	303.7
	-	-	LongGul_B	32.6
	-	-	GWindS2_B	126.1
	-	-	GWindS5_B	126.1
	-	-	GWindS6_B	126.1
	-	-	GWindS8_B	126.1
	-	-	Matakitaki	196.7
	-	-	Taramakau	245.8
	-	-	Whitcombe	147.5
	-	-	GWindS4_B	126.1
	-	-	KaiweraDowns_B	536.7
2049	GWindS2_B	126.1	SthCantSolGeneric5	181.4
	GWindS5_B	126.1	GWindR40_13	135.1
	GWindS6_B	126.1	-	-
	GWindS8_B	126.1	-	-
	Matakitaki	196.7	-	-
	Taramakau	245.8	-	-
	Whitcombe	147.5	-	-
	GWindS4_B	126.1	-	-
	Hayes1_B	320.3	-	-
	Hayes2_B	338.1	-	-
	Hayes3_B	338.1	-	-
	Hayes4_B	338.1	-	-
	KaiweraDowns_B	536.7	-	-

Source: Calculated by HoustonKemp using data from plant_investment.csv

3.3 Prices for consumers decrease even as energy prices increase

The Authority finds that consumers will pay less overall for electricity as a result of its proposed TPM. For example, in its central scenario with baseline assumptions, the Authority estimates that average total electricity prices will reduce by 17.1 per cent as a result of the proposed TPM. As a weighted average across sensitivities in the central scenario, average total electricity prices will reduce by 11.8 per cent.

At the same time, the Authority's modelling finds that generators tend to receive higher prices as a result of its proposed TPM. Under the proposed TPM, the Authority's modelling indicates that average wholesale prices will increase by 3.7 per cent in the central scenario with baseline assumptions, and by 10.9 per cent on a weighted average basis across sensitivities in the central scenario. These results occur because the Authority assumes that some transmission costs will be recovered in higher fixed charges, to which it assumes that load customers are not responsive. We discuss these assumptions in more detail at section 4 below.

Table 3.3 below summarises the changes in price estimated by the Authority on a weighted average basis in the central scenario. These average prices are calculated on a present value basis, giving progressively lower weight to future consumption in order to appropriately account for the time value of money.

Table 3.3: Changes in electricity prices estimated by the Authority in the central scenario

Period of use	Status quo	Proposed TPM	Difference
	$ per MWh	*$ per MWh*	*%*
Electricity prices including transmission charges			
Peak	358.08	280.05	-21.8%
Shoulder	168.38	146.16	-13.2%
Off-peak	60.25	74.90	+24.3%
Average	**176.01**	**155.21**	**-11.8%**
Electricity prices excluding transmission charges			
Peak	203.82	254.39	+24.8%
Shoulder	157.87	131.85	-16.5%
Off-peak	57.08	66.44	+16.4%
Average	**126.09**	**140.02**	**+10.9%**

Source: Electricity Authority worksheet 'summary_results.csv'

The changes in prices that the Authority estimates are substantial given the relative contribution of transmission charges to electricity prices in New Zealand and are not highlighted in the Authority's consultation paper or in its technical paper.

4. Response by load customers to proposed charges

In the New CBA, the Authority has changed materially the assumptions that it makes about how load customers respond to charges under its proposed TPM. In this section we:

- describe the framework used for modelling load customer response in the 2019 and Revised CBAs;
- contrast this with the Authority's approach to modelling customer response in the New CBA; and
- review the rationale for the Authority's changes.

4.1 Previous framework modelling customer response

In the 2019 and Revised CBAs, the Authority sought to estimate the effect of removing the RCPD and HVDC charges and their replacement with the benefit-based and residual charges by assuming that:

- under the status quo, interconnection charges are recovered with a per kWh charge applying in peak periods; and
- under the proposed TPM guidelines, benefit-based and residual charges would be recovered with a per kWh charge applying equally across peak, shoulder and off-peak periods.

The TPM guidelines proposed at that time would not have set benefit-based and residual charges on this basis. However, the Authority explained that this was a nonetheless a reasonable basis for estimating load customer responses to these charges, for example:[30]

> This is not how Transpower would charge transmission customers for transmission interconnection costs under the proposal. However, the approach we have followed in the CBA ensures that, under the demand modelling, consumers still consider the overall cost of electricity when making their consumption decisions. That is, we assume consumers only increase their overall electricity consumption if the average cost of electricity falls relative to other goods and services available to them.

This was not a contentious aspect of the Authority's modelling of the net benefits of its proposal. Neither we nor Axiom Economics (for Transpower) raised concerns with the simplified representation of the status quo and proposal using per kWh charges, although we both raised some concerns with the Authority's estimation of demand elasticities.

The Authority's approach to modelling the recovery of interconnection costs in the 2019 and Revised CBAs made analysis of the economic effects of its proposal simpler than might otherwise have been the case. Since the same interconnection costs are recovered from load customers under both the status quo and the proposal (but for a transfer from generators to load customers), the benefits of reduced charges in peak times are offset by the costs of increased charges in shoulder and off-peak times, and the net economic effects depends on differences in customer response across these periods and changes in generation costs.

4.2 The Authority's new approach to modelling customer response

In its New CBA, the Authority has adopted a new approach to modelling load customer response to its proposed charges. The Authority now assumes that:[31]

[30] Electricity Authority, *CBA approach, methods and assumptions: TPM issues paper 2019*, Technical paper, 23 July 2019, para 2.10.

[31] Electricity Authority, *Proposed TPM 2021: CBA approach, methods and assumptions*, Technical paper, 19 October 2021, paras 2.12-2.13.

- benefit-based charges for schedule 1 investments (ie, the seven historical investments for which charges have been determined by the Authority in its TPM guidelines and not by Transpower in its TPM) are wholly fixed and therefore are not modelled as per kWh charges;
- benefit-based charges for new investments become fixed once those investments have been commissioned and therefore are not modelled as per kWh charges; and
- residual charges are partially fixed, reflecting that consumption behaviour reflects prices only on a delayed basis, and therefore only 55 per cent of residual charges are treated as per kWh charges.

The Authority states that instead of treating the fixed component of charges as a per kWh equivalent charge, it models these as a reduction in consumer income, leading to a shift inward of the demand curve.[32]

These changes to the underlying assumptions for how the Authority estimates benefits are very important. By treating new charges as fixed or partially fixed, the Authority effectively treats its proposed TPM as if consumers were facing lower charges as compared to the status quo. Lower charges give rise to higher consumption and reduced deadweight loss. These revised assumptions would be expected to be reflected in higher estimates of consumer surplus and reduced estimates of deadweight loss.

By contrast, in the Revised CBA, the Authority's modelling assumptions meant that there was no reason to expect it would find a material net benefit relating to changes in the use of the grid. This is because reduced deadweight losses in peak periods would be expected to be substantially cancelled out by increased deadweight losses in shoulder and off-peak periods.

The Authority does not disclose the impact of the changes on its quantified estimates of net benefits. However, we expect that this effect would substantially increase consumer surplus because the Authority assumes that under its proposed TPM customers do not face a marginal price for the recovery of benefit-based charges and 45 per cent of residual charges. Although there will be an income effect, we expect that this would be relatively small since expenditure on electricity constitutes a relatively small part of total customer expenditure.

Consistent with this observation, the results of the New CBA indicate that the Authority's proposed TPM will give rise to much greater increases in consumption than indicated by the Revised CBA. Table 4.1 below compares the changes in consumption (as against the status quo) estimated by the Authority for the Revised CBA and the New CBA.[33] These results suggest that there will be an increase in consumption in peak and off-peak periods under the proposed TPM and a reduction in shoulder consumption.

[32] Electricity Authority, *Proposed TPM 2021: CBA approach, methods and assumptions*, Technical paper, 19 October 2021, para 2.103.

[33] We note that the increases in consumption that we calculate are in the same directions but different to those reported by the Authority in its consultation paper – see Electricity Authority, *Proposed transmission pricing methodology*, Consultation paper, 8 October 2021, paras D.83-D.87. The Authority does not disclose the source of or basis for its comparisons, so we are unable to reconcile the differences between these estimates.

Table 4.1: Comparison of changes in consumption in Revised CBA and New CBA

Time of use	Revised CBA			New CBA		
	Status quo annual consumption (GWh)	Proposed TPM guidelines annual consumption (GWh)	Per cent change	Status quo annual consumption (GWh)	Proposed TPM annual consumption (GWh)	Per cent change
Peak	5,101	5,168	+1.3%	5,403	5,707	+5.6%
Shoulder	9,600	9,522	-0.8%	9,888	9,634	-2.6%
Off-peak	30,677	30,581	-0.3%	31,108	31,717	+2.0%
Total	45,379	45,271	-0.2%	46,399	47,058	+1.4%

Source: Electricity Authority worksheets 'aob.csv' and 'rcpd.csv' for the New CBA and 's_1.0_1.05_0.01_0.9rcpd.csv' and 's_1.0_1.05_0.01_0.9aob.csv' for the Revised CBA.

4.3 Rationale for changing assumptions

4.3.1 The Authority does not explain the basis for changing its assumptions

The Authority does not clearly explain why it has made these changes to its modelling of customer response.

The Authority states that these changes to its modelling of customer response are *'necessary for distinguishing the different effects of [benefit-based charges] and residual charges and thus to account for trade-offs embedded in the proposed TPM'*.[34] However, this does not explain why the Authority's modelling approach has changed. The TPM guidelines that were being analysed by the Revised CBA contained the same requirements as the proposed TPM in respect of:

- the requirement for benefit-based charges to be fixed; and
- the requirement for residual charges to be charged based on historical anytime maximum demand.

For example, clause 24 of the TPM guidelines states:

> 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. [bold and underline in original]

Further, clauses 28 and 30 of the TPM guidelines requires that the residual charge is to be allocated in proportion to the average of each customer's anytime maximum demand over the four years from 1 July 2014 to 30 June 2018 and for this allocation to change in line with changing average energy usage over an historical period between five and eight years prior to each pricing period.

There is no essential difference in the requirements under the proposed TPM (as compared to the TPM guidelines) that would require the Authority to use a completely different set of assumptions for estimating their costs and benefits. At face value, the Authority appears to have used one set of modelling assumptions to justify its TPM guidelines and another set of modelling assumptions to justify its proposed TPM under those guidelines, without a clear rationale for what has motivated those changes.

It would build confidence for the Authority to be able to demonstrate that these changes to customer behaviour, which it has not been able to explain by reference to changes in external circumstances, are not essential to its findings, ie, to demonstrate:

[34] Electricity Authority, *Proposed TPM 2021: CBA approach, methods and assumptions*, Technical paper, 19 October 2021, paras 2.12-2.14.

- the effect on the outcome of its Revised CBA, *with* the changes in assumptions made in the New CBA; and
- the effect of the outcome of its New CBA, *without* the changes in assumptions made in the New CBA.

4.3.2 Benefit-based charges are not fixed

We understand that the Authority's changes bring its assumptions more closely into line with its underlying theory of how benefits might be realised from its proposal, ie, that charges become more fixed and therefore that inefficient responses to transmission charges are reduced. However, in our opinion, the approach in the New TPM to treating benefit-based charges as wholly fixed is inaccurate, and the approach under the Revised TPM was a more accurate reflection of long run customer responses.

The approach used in the Revised CBA assumes that, over the long run, customers respond to the average prices that they are charged – or as the Authority states:

> … we assume consumers only increase their overall electricity consumption if the average cost of electricity falls relative to other goods and services available to them.

The assumptions in the New CBA suggest that the Authority believes that load customers could face substantial increases in charges but not respond to these if they are substantially fixed. We have significant reservations to this approach.

Benefit-based charges are not fixed in the long run. The Authority has proposed no less than 13 different types of events that might trigger adjustment of benefit-based charges.[35] These include events such as:

- a new customer connecting to the grid, or an existing customer leaving the grid; and
- an existing customer making a substantial and sustained increase to its use of the grid.

We expect that these clauses would operate to ensure that benefit-based charges adjust so as to continue to reflect estimated benefits from use of the grid, and therefore (to some extent) to reflect changes in grid usage over time. Indeed, we expect that this is the purpose of these adjustment mechanisms, without which the proposed charges would be unlikely to have any durability.

Over the long run, there are therefore good grounds to suppose that benefit-based charges would adjust to reflect sustained changes in consumption and the associated benefits and that load customers would be capable of responding to the expectation of such changes. These observations are not consistent with the Authority's approach of treating benefit-based charges as wholly fixed in the long run.

Further, we note the Authority's modelling of customer response assumes that all customers face electricity prices that reflect the structure of the TPM. However, many electricity customers (ie, mass-market customers) will not directly face charges calculated under the proposed TPM. Rather, these customers will face electricity prices set by their electricity retailer through competition with other retailers. Retailers themselves do not directly face transmission charges, since these are incorporated into distribution charges. Similar observations were made by NZIER in its commentary on the Authority's 2019 consultation paper.[36]

A retailer might be able to reduce its risks by levying fixed prices in line with the contribution of fixed transmission charges. However, because they are competing to win customers, retailers may need to consider other factors such as customer preferences in determining the structure of prices.

[35] Electricity Authority, *Proposed transmission pricing methodology*, 8 October 2021, para 82(1).

[36] See: NZIER, *TPM 2019 cost benefit analysis: initial review*, 1 October 2019, pp 4-8.

5. Calculation of consumer surplus

We have previously raised concerns about the Authority's approach to calculating the change in consumer surplus in the 2019 and Revised CBAs.

In its New CBA, the Authority introduces a new approach to calculating the change in consumer surplus. This new approach effectively responds to some of the concerns that we have previously raised but raises new challenges that are not well described in the Authority's consultation documentation.

In particular, the new approach to calculating the change in consumer surplus requires the Authority to form a view of the 'maximum price', ie, the price at which load customers would not consume any electricity. However, there is no reliable evidentiary basis for the Authority's assumption.

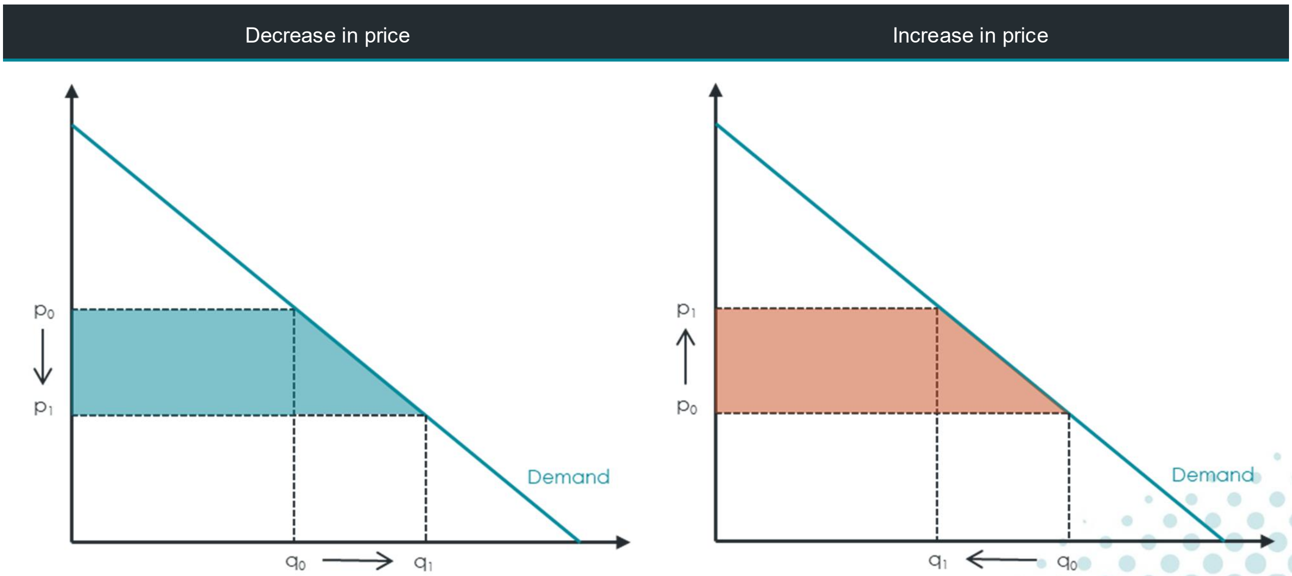
We understand that the maximum price assumption is determinative of the magnitude of the change in consumer surplus, which is in turn the most important component of the Authority's estimate of net benefits for its proposed TPM.

5.1 Concerns previously raised about the change in consumer surplus

In the 2019 and Revised CBAs, the Authority calculated the change in consumer surplus under the assumption that changes in price due to changes in the TPM gave rise to movements along a linear demand curve. For example, figure 5.1 below shows:

- shaded in blue, the increase in consumer surplus calculated by the Authority in connection with a decrease in price, which the Authority assumed to occur in peak periods with the removal of the RCPD charge; and
- shaded in red, the decrease in consumer surplus calculated by the Authority in connection with an increase in price, which the Authority assumed to occur at shoulder and off-peak periods.

Figure 5.1: Change in consumer surplus in the 2019 and Revised CBAs



In our review of the Authority's 2019 CBA, we observed that this approach could not validly be applied. The Authority's assumption that changes in price and quantity were movements along a demand curve was contradicted by its own results, some of which indicated that changes in price and quantity would have required an *upward sloping* demand curve for the assumption to hold. We explained that various effects captured by the Authority had likely led to movements *of* the demand curve as well as movements *along* the demand curve.[37] Similar concerns were also raised by Axiom Economics' review of the 2019 CBA.[38]

Until now, the Authority has apparently not accepted this critique, since it made no changes to its calculation to reflect our concerns.

5.2 The Authority's new approach for calculating change in consumer surplus

In its New CBA, the Authority has made a substantial change to its calculation of the change in consumer surplus. Its new calculation assumes that there is a shift *of* the demand curve, as well as a shift *along* the demand curve. The Authority attributes the shift *of* the demand curve to the fixing of benefit-based and residual charges, which it states will not act as prices but will effectively reduce load customers' incomes, leading to an inward movement of the demand curve. Consistent with these assumptions, the Authority now calculates the change in consumer surplus as the total consumer surplus under its proposal less the total consumer surplus under the status quo.

This new calculation is set out pictorially at figure 5.2 below, which shows examples of:

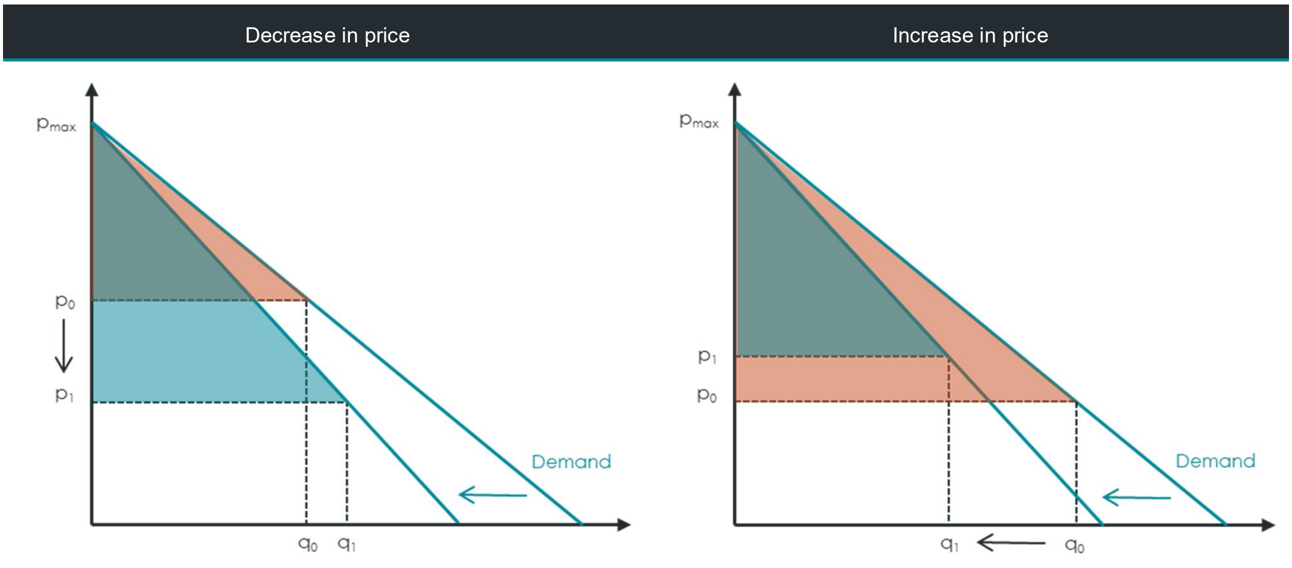
- a decrease in price, combined with a shift inward of the demand curve, giving rise (in this example) to a higher market quantity and areas of increased consumer surplus (shaded in blue) and reduced consumer surplus (shaded in red); and
- an increase in price, combined with a shift inward of the demand curve, giving rise to a lower market quantity and areas of reduced consumer surplus (shaded in red).

In both diagrams, the area of intersection between the blue shaded and red shaded areas represents consumer surplus that is achieved both under the status quo and the proposal and is therefore neither an increase nor a decrease in consumer surplus.

[37] HoustonKemp, *Review of the cost benefit and options analysis of the EA's proposed TPM guidelines*, 30 September 2019, pp 62-64.

[38] Axiom Economics, *Economic review of transmission pricing review consultation paper*, September 2019, p 130.

Figure 5.2: Change in consumer surplus in the New CBA



In our opinion, this change in approach represents an improvement in the Authority's approach to the calculation of the change in consumer surplus. It opens the prospect, at least in principle, that the Authority's calculation may not be affected by some of the errors that previously affected it.

5.3 The Authority's calculation of the maximum price

The Authority's change in approach introduces some new challenges, as well as addressing old ones. Calculating consumer surplus as the total area under a demand curve requires information about the willingness of load customers to pay (ie, demand) for all quantities equal to or less than the quantity consumed.

In this section, we explain that the Authority has no evidentiary basis for its assumptions about the shape of the demand curve – indeed its assumptions are inconsistent with the evidence that it has collected about consumer demand that it uses to inform the shape of the demand curve. Further, by its own description, the estimates of consumer surplus in the New CBA are extremely sensitive to these assumptions.

The Authority assumes that the demand curve is linear, and for each time of day calculates the maximum price which load consumers would be willing to pay (p_{max}) as being 135 per cent greater than the average price for that time of day between 2008 and 2020, amounting to:[39]

- maximum peak prices of $600 per MWh;
- maximum shoulder prices of $240 per MWh; and
- maximum off-peak prices of $190 per MWh.

Reflecting the Authority's assumption, in figure 5.2 above we draw an inward shift of the demand curve due to decreases in income resulting in an inwards *rotation* of the demand curve about the maximum price.

The Authority explains that the maximum price is calculated by reference to its estimate of the long run elasticity of demand, being -0.74. Even though load customers may be willing to pay much higher amounts for electricity in the short run, the Authority asserts that over the long run customers faced with very high

[39] Electricity Authority, *Proposed TPM 2021: CBA approach, methods and assumptions*, Technical paper, 19 October 2021, paras 2.12-2.121.

prices would substitute to distributed energy sources. In other words, the Authority calculates consumer surplus by reference to estimates of load customers' long-term willingness to pay.[40]

The significance of the maximum price being 135 per cent higher than historical prices is not directly explained by the Authority, but this mark-up appears to be consistent with the increase in price that would give rise to a 100 per cent decrease in quantity, on the assumption that the Authority's elasticity estimate of -0.74 could be applied to a quantity shift of this magnitude.[41]

The Authority notes that using lower elasticities (such as a short run elasticity) would give rise to higher maximum prices and potentially result in much greater increases in consumer surplus.[42] This finding is problematic, given that in our opinion there is no evidentiary basis for the Authority's estimates of maximum prices and therefore its calculation of the change in consumer surplus that depends on these estimates.

The Authority calculates the change in consumer surplus under the assumption that the demand curve is a straight line between the price-quantity pair (either in the status quo or under the proposal) and the maximum price. This assumption appears to be one of convenience, rather than being based on fact or evidence.

First, this assumption is inconsistent with the basis on which the Authority has estimated the relationship between demand and price. In estimating elasticity of demand, the Authority has assumed a 'log-log' relationship between quantity and price, ie, a *curved* demand curve for which there is always some demand no matter how high the price.[43] Elasticity of demand estimated on this basis cannot inform calculation of a price at which there would be no demand.

This distinction is demonstrated in figure 5.3 below, which shows how the Authority has calculated the maximum price assuming a linear demand curve (shown in black) projected from historical prices and quantities (p_h and q_h). However, the slope used by the Authority for this demand curve has been established by reference to an elasticity estimate that is drawn from a curved demand function (shown in blue) that *never* touches the vertical axis. The calculation of maximum price does not correctly reflect the information provided by the Authority's elasticity estimates.

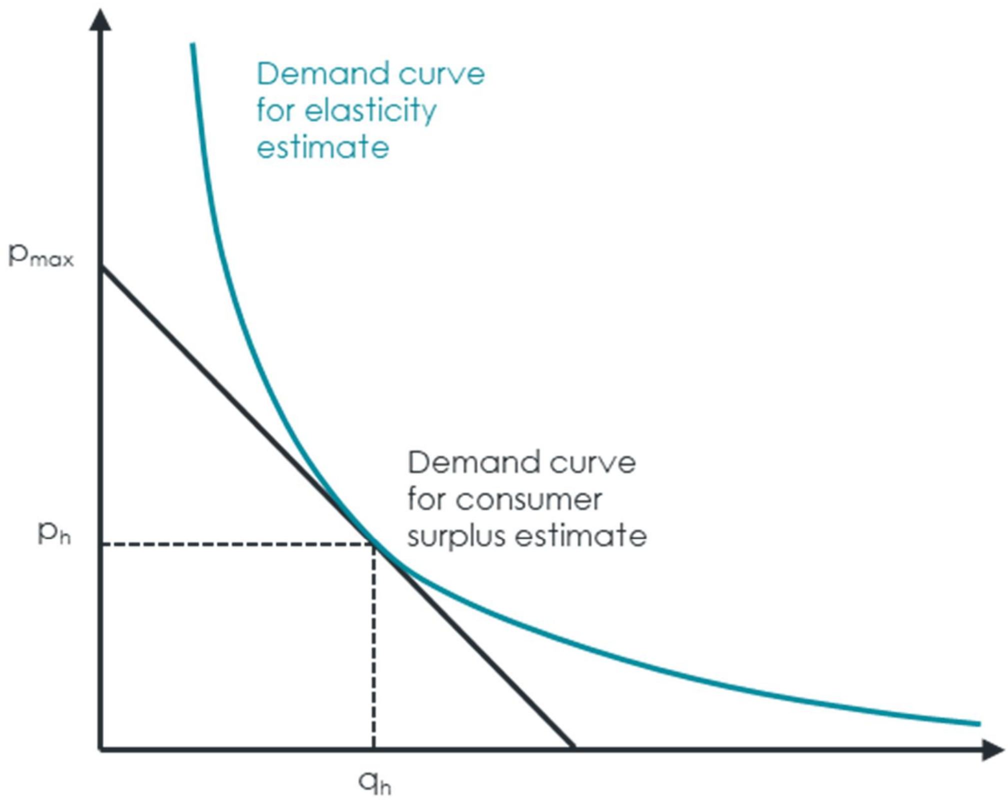
[40] By contrast, the Authority's approach to calculating producer surplus appears to focus predominantly on short run considerations.

[41] That is, 135 per cent multiplied by -0.74 equals negative 100 per cent.

[42] Electricity Authority, *Proposed TPM 2021: CBA approach, methods and assumptions*, Technical paper, 19 October 2021, paras 2.12-2.123.

[43] Electricity Authority, *Proposed TPM 2021: CBA approach, methods and assumptions*, Technical paper, 19 October 2021, paras 2.12-2.144-2.149.

Figure 5.3: Inconsistency of maximum price with the Authority's elasticity estimate



Second, the elasticity of demand changes along a linear (or straight line) demand curve. For example, on a linear demand curve:

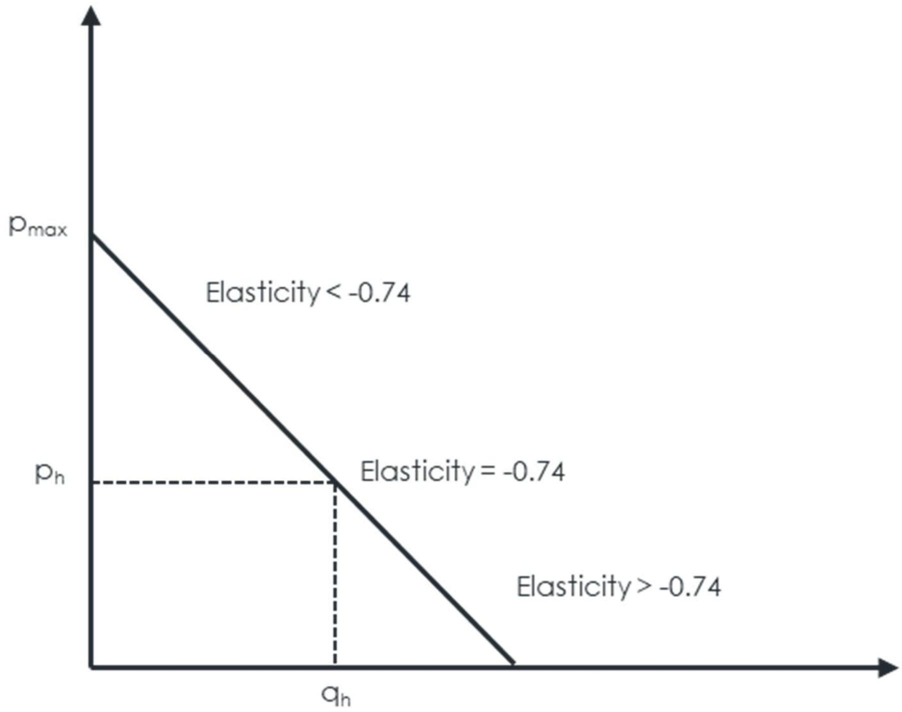
- where there is low volume and high willingness to pay, elasticity of demand is higher; and
- where there is high volume and low willingness to pay, elasticity of demand is lower.

It follows that, on a linear demand curve, an estimate of elasticity is only a 'point' estimate, and only applies in the region immediately around that point. However, when calculating the maximum price, the Authority has assumed that the elasticity of demand remains constant at -0.74 at every quantity at or below its estimate of electricity consumption.

This is illustrated in figure 5.4 below, which shows the Authority's straight line demand curve that it uses for calculating consumer surplus. Although the Authority has calculated the maximum price under the assumption that its elasticity estimate of -0.74 can be used to estimate the price increase that would induce load customers to reduce consumption to zero, on a straight line demand curve:

- the elasticity estimate of -0.74 applies only at a single point or region on the demand curve, ie, at the historical prices and quantities; and
- the elasticity of demand at quantities less than historical estimates will be more negative (ie, more elastic) than at this point or region of the curve.

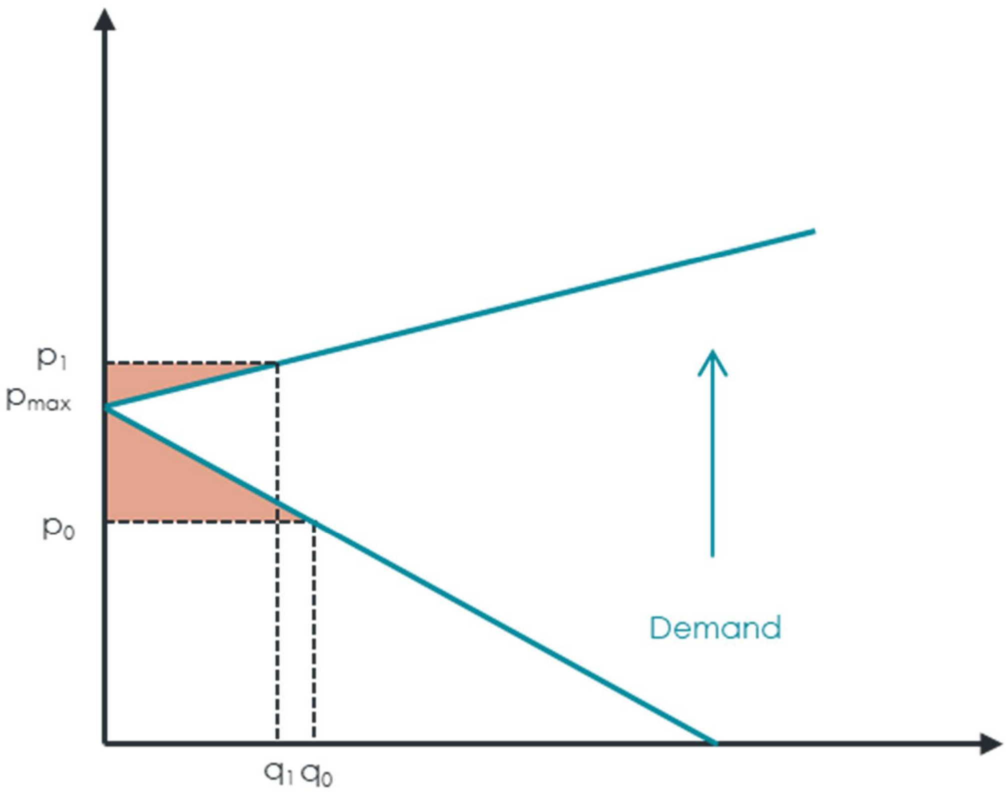
Figure 5.4: Elasticity of demand changes along a straight line demand curve



Finally, we also note that, from time to time the Authority finds prices that *exceed* those that it cites as a ‘maximum price’. If the Authority continues to calculate consumer surplus mechanistically on the assumptions that are described above, then the demand curve passing through the price-quantity pair and this maximum price will be *upward-sloping*, and consumer surplus will be a negative area *above* this demand curve.

Figure 5.5 below demonstrates this effect, showing that an increase in price from below maximum price to above maximum price causes the demand curve to become upward sloping. In this scenario, consumer surplus under the proposal is negative, since the price for all quantities *exceeds* willingness to pay and therefore the change in consumer surplus is also negative.

Figure 5.5: Consequences of prices being higher than maximum price



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Examples such as those depicted at figure 5.5 above are a consequence of making simplifying assumptions about demand curves using the Authority's approach.

6. Calculation of producer surplus

The Authority calculates net benefits as including only the change in consumer surplus. However, since the Revised CBA the Authority has also presented as part of its modelling an estimate of the change in total surplus (incorporating changes in producer surplus). In its Revised CBA, it explained that this calculation ensured that '*the guidelines would not undermine efficient market dynamics*'.[44]

In its Revised CBA, the Authority made an error that caused it to estimate an increase in producer surplus, when in fact producer surplus was lower under its proposed TPM guidelines. It has corrected this error in the New CBA.

In the New CBA, the change in producer surplus is very substantial, amounting to $5.6 billion in present value terms. Although this is consistent with the Authority's modelling that indicates that its proposed TPM will give rise to increases in wholesale electricity prices of 10.9 per cent, it is not clear to us that either of these outcomes is plausible in the context of the overall contribution of transmission charges to electricity prices.

6.1 Errors in the calculation of producer surplus in the Revised CBA

In the Revised CBA, the Authority's analysis of producer surplus appeared to show that generators would benefit as a result of the changes to the TPM guidelines. For example, the Authority's modelling indicated that:

- the median change in consumer surplus across 113 sensitivities was $715 million the change in producer surplus associated with the sensitivity that gives rise to the median change in consumer surplus was $431 million;[45] and
- the median change in total surplus was $771 million, suggesting a small benefit for generators of $56 million as compared to the median change in consumer surplus.[46]

However, the Authority's calculation of producer surplus contained an error that caused it to overstate the change in producer surplus by over $1 billion in present value terms.

In a document provided to the Authority in May 2020, John Culy explained that the Authority had calculated the change in producer surplus using quantities that were lower than those used for the change in consumer surplus. Specifically, the Authority calculated producer surplus from a dataset in which the quantity of electricity sold by generators amounted to:[47]

- 99 per cent of the quantity of electricity purchased by consumers from grid-connected generation in peak periods;
- 66 per cent of the quantity of electricity purchased by consumers from grid-connected generation in shoulder periods; and
- 70 per cent of the quantity of electricity purchased by consumers from grid-connected generation in off peak periods.

[44] Electricity Authority, *Transmission pricing methodology 2020 guidelines and process for development of a proposed TPM*, Decision, 10 June 2020, para 15.11.

[45] Electricity Authority, *Summary_costs_and_benefits.xlsx*, 17 April 2020, worksheet 'Central_weighted', cells F107 and H107.

[46] Electricity Authority, *Summary_costs_and_benefits.xlsx*, 17 April 2020, worksheet 'Central_weighted', cells O6 and Q6.

[47] This statement is based on our review of: Electricity Authority, *central.py*, 16 April 2020.

We show in table 6.1 below that the quantities used by the Authority in its 'earnings' worksheet, which it uses to calculate producer surplus, are lower than those used elsewhere in its analysis.

Table 6.1: Calculation of annual average quantity in the Revised CBA, 2022 - 2049

Time of use	'gen_aob' worksheet quantities	'earnings' worksheet quantities	Difference
	GWh	*GWh*	*%*
Peak	5,168	5,117	-1%
Shoulder	8,570	5,666	-34%
Off-peak	27,523	19,266	-30%

Source: Calculated by HoustonKemp in the median scenario using s_1.0_1.05_0.01_0.9gen_aob.csv and s_1.0_1.05_0.01_0.9earnings.csv

Although the Authority may have had a purpose for reducing volumes in the 'earnings.csv' dataset, it is not apparent that this purpose would be relevant to calculating producer surplus. As a matter of principle, producer surplus and consumer surplus should be calculated using consistent measures of volume.

The Authority's estimate of the overall change in producer surplus can be decomposed into changes in peak, shoulder and off-peak periods. When we take into account that the Authority has used quantities of electricity that are too low in peak periods by 1 per cent, too low in shoulder periods by 34 per cent and too low in off-peak periods by 30 per cent, an estimate of producer surplus that corrects for these errors gives considerably more weight to outcomes in the shoulder and off-peak period than contemplated by the Authority.

Table 6.2 below shows that when the calculation of producer surplus receives the correct quantity weighting, the Authority's proposal can be shown to overestimate producer surplus by $1,116.7 million. That is, when correct quantities are used, the Authority's results indicate that producer surplus would reduce by $685.5 million, rather than increase by $431 million.

Table 6.2: Change in producer surplus in the Revised CBA, 2022 - 2049

Time of use	'gen_aob' worksheet quantities	'earnings' worksheet quantities	Difference
	$ million	*$ million*	*$ million*
Peak	2,787,3	2,815.4	28.1
Shoulder	-1,607.6	-2,431.6	-824.0
Off-peak	-748.5	-1,069.3	-320.8
Total	**431.2**	**-685.5**	**-1,116.7**

Source: Calculated by HoustonKemp in the median scenario using s_1.0_1.05_0.01_0.9gen_aob.csv and s_1.0_1.05_0.01_0.9earnings.csv

This result is also more consistent with the other outcomes of the Authority's analysis in its Revised CBA, which suggested that generators would serve lower quantities of electricity at reduced average prices under its proposal.

6.2 Authority's calculation of producer surplus in the New CBA

In its New CBA the Authority has amended its calculation of producer surplus so that it no longer reduces quantities. We observe this change in approach by two means, ie:

- the Authority's Python code has been amended so that it no longer reduces quantities before entering that information into the 'earnings' worksheet that is used to calculate producer surplus;[48] and
- a comparison of the quantities in the 'gen_aob' and 'earnings' worksheets, that were different in the Revised CBA, are now identical as indicated in table 6.3 below.

Table 6.3: Calculation of annual average quantity in the New CBA, 2022 - 2049

Time of use	'gen_aob' worksheet quantities	'earnings' worksheet quantities	Difference
	GWh	GWh	%
Peak	5,706	5,706	0%
Shoulder	9,634	9,634	0%
Off-peak	31,717	31,717	0%

Source: Calculated by HoustonKemp in the central scenario using 'gen_aob.csv' and 'earnings.csv'

The Authority's calculation of producer surplus now indicates that as between the status quo and the Authority's proposed TPM, producer surplus increases by $5.6 billion in the central scenario on a weighted average mean basis.[49]

This increase in producer surplus appears consistent, at face value, with the Authority's estimates (which we collate earlier in this report) that generators will enjoy wholesale prices that are on average 10.9 per cent higher under its proposed TPM than the status quo, and that they will sell 1.8 per cent more electricity at these higher prices.

However, this degree of increase in producer surplus is entirely inconsistent with the Authority's modelling of changes in generation costs, which we discuss in section 8.1 below. Specifically, the Authority's analysis suggests that generation costs increase by $435 million in present value terms in its central scenario, yet generators will be able to enjoy revenue increases far in excess of this, and therefore substantial overall increases in profitability and surplus. Indeed, one of the Authority's sensitivities finds that producer surplus will increase by $44 billion.[50]

[48] This statement is based on our review of: Electricity Authority, *central.py*, 20 October 2021.

[49] Electricity Authority, *Summary_costs_and_benefits.xlsx*, October 2021, worksheet 'Central', cells T4 and U4.

[50] Based on HoustonKemp analysis of Electricity Authority, *summary_results.csv*, October 2021. The relevant sensitivity is s_1.01_1.005_-0.005_2024_0.5.

7. Welfare transfers in the New CBA

A CBA assesses net benefits by considering benefits or costs to society. Consistent with this, benefits that are received by one party that are in turn costs to another party are not included as benefits in a CBA. They are referred to as 'transfers' of value between the parties. A transfer does not increase total benefits in a market, it simply reallocates benefits between parties.

These observations are consistent with the Authority's own interpretation of its statutory objective. In its paper discussing this interpretation, the Authority states that it intends to exclude transfers when using CBA to assess net benefits to electricity consumers and refers to this approach as 'standard'.[51]

The exclusion of transfers is consistent with materials on CBA published by the Commonwealth of Australia and the United States Office of Management and Budget (OMB).[52] OMB's guidance also provides the key insight that benefits and costs should reflect the use of resources (that is, the value derived from their consumption and the costs incurred in their supply) rather than monetary payments for these resources (that is, their prices).

These core economic principles sit in tension with the approach that the Authority takes to calculating the net benefits of its TPM proposal in the New CBA – and similarly affected its 2019 and Revised CBAs. Specifically, the Authority includes as quantified benefits to society the change in consumer surplus, which reflects the Authority's calculation of the benefits that consumers enjoy under its proposed TPM. Conceptually, the Authority's estimate of the change in consumer surplus:

- is comprised of both benefits to society and transfers from generators; and
- is calculated so as to reflect changes in the prices at which electricity is exchanged, rather than changes in the use of resources.

7.1 Concerns previously raised about inclusion of transfers

In our previous reviews of the Authority's 2019 and Revised CBAs, we undertook calculations that demonstrated that the vast majority of the increase in consumer surplus was comprised of transfers.[53] We were able to demonstrate this on a simple basis because under the assumptions of those CBAs, the Authority's proposed TPM guidelines were assumed to shift the recovery of transmission costs from being recovered only in peak periods to being recovered across all periods. Since the same costs were recovered from consumers in prices, consumers did not pay more or less for electricity in total as a direct result of these changes. Whether society benefits from the changes in peak, shoulder and off-peak prices depends on changes in the use of electricity, ie:

- the extent to which consumers increase their usage of electricity at peak periods in response to lower prices; as against
- the extent to which consumers decrease their usage of electricity in shoulder and off-peak periods in response to higher prices.

[51] Electricity Authority, *Interpretation of the Authority's statutory objective*, 14 February 2011, paras A5-A10.

[52] Commonwealth of Australia, *Handbook of cost benefit analysis*, January 2006, p 27; and United States Office of Management and Budget, *Regulatory analysis*, Circular A-4, 17 September 2003, p 38.

[53] See: HoustonKemp, *Review of the cost benefit and options analysis of the EA's proposed TPM guidelines*, 30 September 2019, pp 43-46; and HoustonKemp, *Review of the Electricity Authority's revised cost benefit analysis*, 18 May 2020, pp 2-9.

We showed that of the change in consumer surplus estimated by the Authority, only a small part was attributable to changes in usage, and the vast majority was attributable to changes in prices on the same usage – thereby being a transfer.[54]

7.2 Transfers in the New CBA

In the Authority's New CBA, this method of identifying transfers can no longer be applied due to two changes to the assumptions and approaches that underpin the CBA, ie:

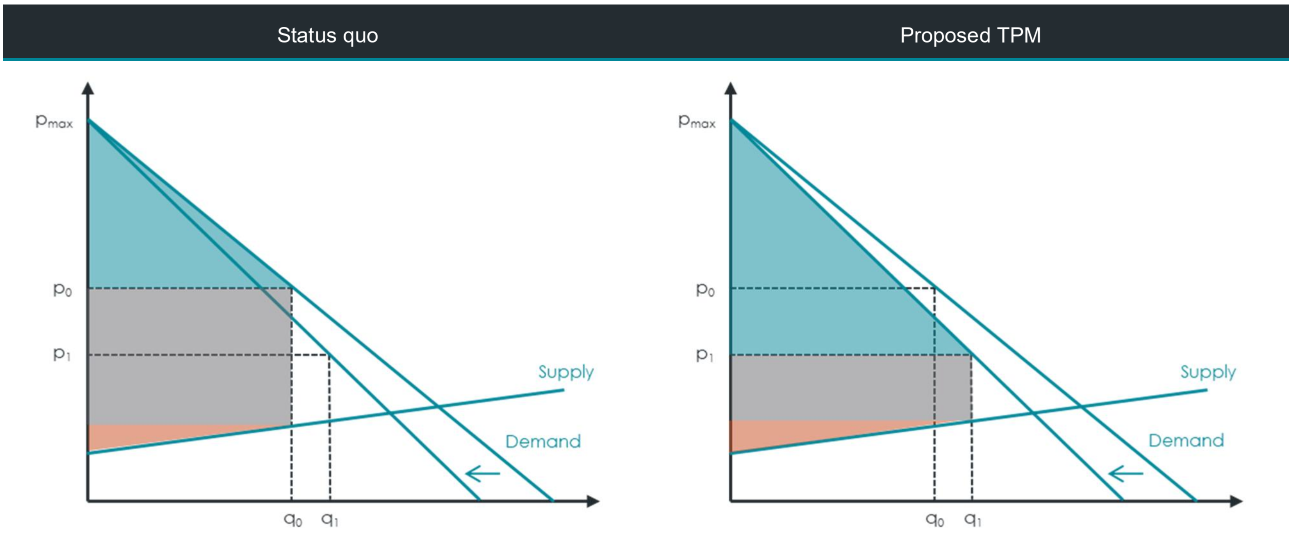
- the Authority's approach to modelling the effects of its proposed TPM, which we discuss in section 2 above, assumes that it gives rise to the recovery of fewer interconnection costs from consumers in prices, with fixed charges effectively being treated as lower income; and
- the Authority's revised approach to estimating the change in consumer surplus, which we discuss at section 5 above, does not isolate the part of this change that is attributable to changes in quantities as it did before, for example see figure 5.1 above.

Instead, the Authority's consideration of its proposal may be seen in figure 7.1 below. The diagram shows a reduction in average prices paid by consumers, reflecting greater fixed charges, giving rise to:

- potentially greater consumer surplus (depending on the scale of the shift inwards of the demand curve) shown shaded in blue;
- increased producer surplus, shown shaded in red; and
- reduced revenue through interconnection prices for Transpower, shown shaded in grey.

For clarity, figure 7.1 is not intended to be descriptive of the Authority's modelling of peak, shoulder or off-peak periods. Rather, it indicates potential aggregate effects across all periods of time.

Figure 7.1: Change in consumer surplus in the 2019 and Revised CBAs



The primary benefits of the Authority's proposed TPM that are highlighted in figure 7.1 arise from its assumption that charges are fixed and that customers will not respond to fixed charges. Figure 7.1 shows

[54] Commonwealth of Australia, *Handbook of cost-benefit analysis*, January 2006, p 27; and Office of Management and Budget, *Regulatory analysis*, Circular A-4, 17 September 2003, p 38.

that this assumption gives rise to lower variable prices for consumers and higher variable prices for generators.

However, the fact that consumers are paying lower variable prices and generators are receiving higher variable prices is not itself a benefit if these changes are merely funding new fixed charges imposed on consumers and generators (which are not shown in the figure). That is, a significant part of an increase in the blue shaded area shown in figure 7.1 arises because the overall size of the grey rectangle collected by Transpower in variable charges has reduced (since some variable charges have been replaced with fixed charges). The Authority's technical paper leaves unclear how it has addressed these issues, since it does not indicate that it has deducted these fixed charges from consumer surplus under its proposed TPM.[55]

Although we have previously been able to provide estimates of the extent of transfers in the Authority's estimate of net benefit, we are no longer to do so under the Authority's revised assumptions for modelling load customer response and its new approach for estimating the change in consumer surplus.

As a matter of principle, we expect that the Authority's estimate of net benefits would still contain transfers, but these would be much lower as a proportion of overall benefits than was the case in the Revised CBA. This conclusion logically follows from the assumptions employed by the Authority that we discuss at section 4 and is consistent with the changes in prices that we identify at section 3.3.

This observation does not suggest that we agree with the Authority's new modelling assumptions or that we consider that its modelling outcomes are plausible – merely that these assumptions would be expected to generate (and the outcomes are consistent with) material benefits to both consumers and producers arising from paying fewer transmission charges. Our detailed consideration of the assumptions and modelling outcomes is set out at sections 3, 4 and 5 above.

[55] Electricity Authority, *Proposed TPM 2021: CBA approach, methods and assumptions*, Technical paper, 19 October 2021, paras 2.12-2.117.

8. Costs of serving increased peak demand

In previous advice to Trustpower, we observed that the Authority's calculation of the net benefits of its proposal did not take into account the full costs to the electricity supply chain of expected increases in peak demand. The extent of these expected costs decreased substantially between the 2019 CBA and the Revised CBA, because the Authority modified its modelling assumptions to moderate the amount of battery investment in the status quo and therefore the difference in peak demand between the status quo and its proposed TPM guidelines.[56]

Similar to the 2019 CBA, the New CBA assumes that there is a substantial difference in peak demand as between the status quo and the proposed TPM. For example, table 4.1 above shows that the Authority's analysis in its New CBA suggests that peak demand will be, on average, 5.6 per cent higher under its proposed TPM than under the status quo. The prospect of increases in peak demand of this materiality gives rise to the prospect of increased costs in the electricity supply chain, including:

- the increased cost of electricity generation required in order to supply higher peak demand;
- the increased cost of electricity transmission network capacity required in order to serve higher peak demand; and
- the increased cost of electricity distribution network capacity required in order to serve higher peak demand.

In our opinion, the Authority must take each of these costs into account in the New CBA. Not only are they costs to society that will arise as a consequence of the Authority's proposal, but they are also costs that must be incurred in order to facilitate the benefits that the Authority seeks to show. Increases in consumer surplus caused by increased peak consumption cannot be realised if electricity infrastructure is not capable of serving this consumption.

The Authority has calculated that transmission costs will increase by $281 million in present value terms as a result of these increases in demand in its central scenario. In this section, we show that in the same scenario:

- generation costs increase by $435 million in present value terms, reflecting an increase in investment costs of $586 million and a reduction in variable costs of $151 million; and
- distribution costs increase by $211 million in present value terms, falling between bounds of $77 million and $318 million.

8.1 Changes in generation costs

Since the Authority's estimates that consumption during peak periods will increase by 5.6 per cent and that overall electricity consumption will increase by 1.4 per cent under its TPM proposal, we would expect the cost of producing this electricity to increase. We show in this section that in the Authority's central scenario, the costs of generating electricity are expected to increase by $435 million in present value terms in central scenario.

However, the New CBA does not take into account the changing costs of generating electricity under the Authority's proposed TPM. Specifically, the Authority does not deduct the additional cost of generation from its estimate of net benefits. Although the Authority takes into account the benefits that consumer enjoy from

[56] HoustonKemp, *Review of the cost benefit and options analysis of the EA's proposed TPM guidelines*, 30 September 2019, pp 46-52; and HoustonKemp, *Review of the Electricity Authority's revised cost benefit analysis*, 18 May 2020, pp 10-11.

lower prices due to increased generation investment, it does not take into account the costs of these investments.

The Authority has previously contended that its estimate of electricity prices, reflected in its estimates of consumer surplus, take into account the changing costs of generation, and therefore it does not need to incorporate changing generation costs in its quantified estimates of net benefits.[57] This contention is incorrect, both as a matter of principle and of application.

We note at section 7 above that costs and benefits accounted for in a CBA should reflect the use of resources (that is, the value derived from their consumption and the costs incurred in their supply) rather than monetary payments for these resources (that is, their prices). It follows that the Authority's estimate of net benefits should directly incorporate changes to the costs of producing electricity.

In any case, there is no direct link established by the Authority's modelling between the costs of generation and the price of electricity. Rather the Authority explains that wholesale prices are determined based on an assumption that generators make market offers based on 2020 offers for generation plant of the same type.[58] Since offers are not based on costs, neither are the prices that the Authority calculates using this approach.

Reinforcing this point, we have repeatedly demonstrated to the Authority that its modelling does not produce wholesale price and revenue outcomes that are in line with changing generation costs. For example:

- in its 2019 CBA, the Authority assumed that under its proposed TPM guidelines, generators would make new investment expenditure in generation plants amounting to $1.94 billion in present value terms, even as prices were assumed to decline such that wholesale revenues fell by $3.66 billion;[59] and
- in its Revised CBA, the Authority's modelling suggested that under its TPM guidelines, the cost of producing electricity decreased by $116 million in its baseline scenario[60] but generator revenues fell in total by $1.10 billion under the same assumptions.[61]

Due to its assumptions about the response of load customers to proposed charges that we discuss in section 2 above, in the New CBA the Authority finds that overall consumption increases under proposed TPM. Higher consumption drives higher generation costs. For example, on a weighted mean basis under the central scenario, the Authority's modelling suggests that the present value cost of producing electricity increases by $435 million. This estimate is itself comprised of:

- increases of $586 million from greater investment in generation plants;[62] and

[57] See for example: Electricity Authority, *Response to feedback on the 2019 cost benefit analysis*, Information paper, April 2020, para 9.3

[58] Electricity Authority, *Proposed TPM 2021: CBA approach, methods and assumptions*, Technical paper, 19 October 2021, paras 2.173-2.174.

[59] HoustonKemp, *Review of the cost benefit and options analysis of the EA's proposed TPM guidelines*, 30 September 2019, p 61.

[60] HoustonKemp, *Review of the Electricity Authority's revised cost benefit analysis*, 18 May 2020, p 7. This is for the central scenario with baseline assumptions. However, the spread of generation cost changes is wide, and the median generation cost change across the Authority's 113 sensitivities is a reduction of $5 million.

[61] HoustonKemp, *Review of the Electricity Authority's revised cost benefit analysis*, 18 May 2020, pp 7-8. In this analysis we estimated that total generator revenues reduced by $376 million, but this increases to $1.10 billion when the effect of the quantity adjustments that we discuss in section 5.1 above are reversed.

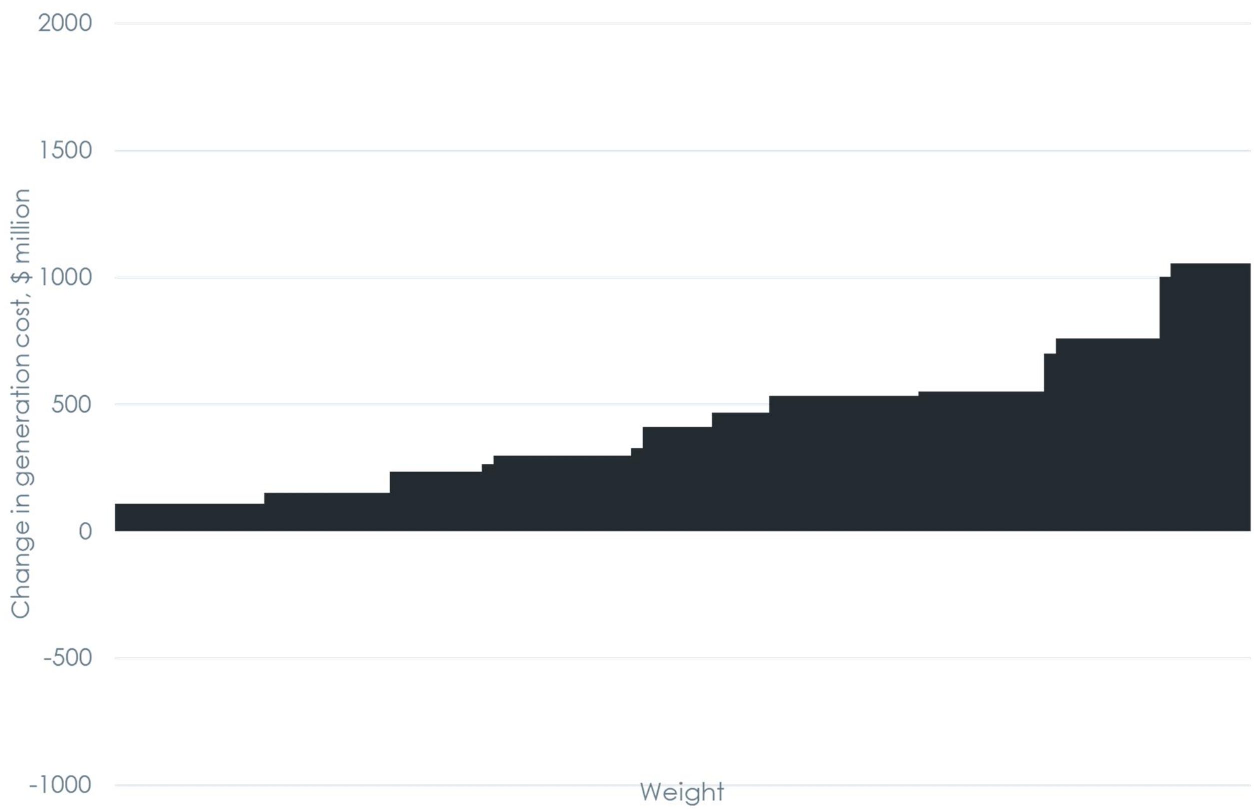
[62] Calculated based on Authority spreadsheets ending in 'generation_investment.csv' available at https://emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis/2021/20211020_CBAforProposedNewTPM/Grid%20use%20model/Sensitivities/Output/Central.

This estimate appropriately considers the costs of investments in generators that have useful lives outside the modelling period, which ends in 2049. We achieve this by amortising the capital cost of each new generation investment using a constant annuity over 40 years at a discount rate of 6 per cent, and comparing the present values of these annuity payments between the proposal and the status quo.

- decreases of $151 million from lower variable costs.[63]

The changes in total generation costs in the central scenario are set out in figure 8.1 below, indicating the range of outcomes and the relative weight placed on each. Although the chart indicates that increase in total generation costs generally falls between $100 million and $1,100 million. There are some isolated negative changes in costs, and changes in costs that exceed $1,100 million, but the weight that the Authority places on these scenarios is so low that that cannot display in figure 8.1.

Figure 8.1: Change in total generation costs in the central scenario



Source: Calculated by HoustonKemp using sensitivity spreadsheets ending in 'generation_investment.csv' and 'earnings.csv'

8.2 Changes in distribution network costs

In the 2019 and Revised CBAs, we criticised the Authority for not factoring into its estimate of the net benefits of its proposal the expected higher costs of investment in distribution networks that would be required to support increases in peak demand.[64]

For the 2019 CBA, we estimated these higher costs to be $292 million, from a range of between $106 million and $428 million.[65] These estimates were based on the Authority's estimates of increases in average peak demand, combined with estimates of distribution long run marginal costs (LRMCs) sourced from Australian businesses.

[63] Calculated based on Authority spreadsheets ending in 'earnings.csv' available at https://emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis/2021/20211020_CBAforProposedNewTPM/Grid%20use%20model/Sensitivities/Output/Central.

[64] HoustonKemp, *Review of the cost benefit and options analysis of the EA's proposed TPM guidelines*, 30 September 2019, pp 46-50

[65] HoustonKemp, *Review of the cost benefit and options analysis of the EA's proposed TPM guidelines*, 30 September 2019, p 50.

For the Revised CBA, applying a substantially similar approach gives rise to higher distribution costs of $11 million, falling within a range of between $4 million and $17 million. We amend the previous approach to use 'ratcheted' average peak demand, as proposed by Axiom Economics in its report.[66] The use of ratcheted peak demand is an improvement on the use of peak demand, since it reflects that investment required to serve an increase in peak demand cannot be reversed if peak demand reduces in subsequent years. The lower effects on distribution costs in the Revised CBA are consistent with the Authority's reduced estimates of the effect of its proposals on peak demand.

We explain in sections 2 and 3 above that, in the New CBA, the Authority assumes that consumption increases under its proposed TPM – particularly consumption during peak periods, which increases by 5.6 per cent on average over the 2022 to 2049 modelling period. Consistent with these assumptions, we would expect these significant increases in peak demand to be supported by greater investment in distribution networks.

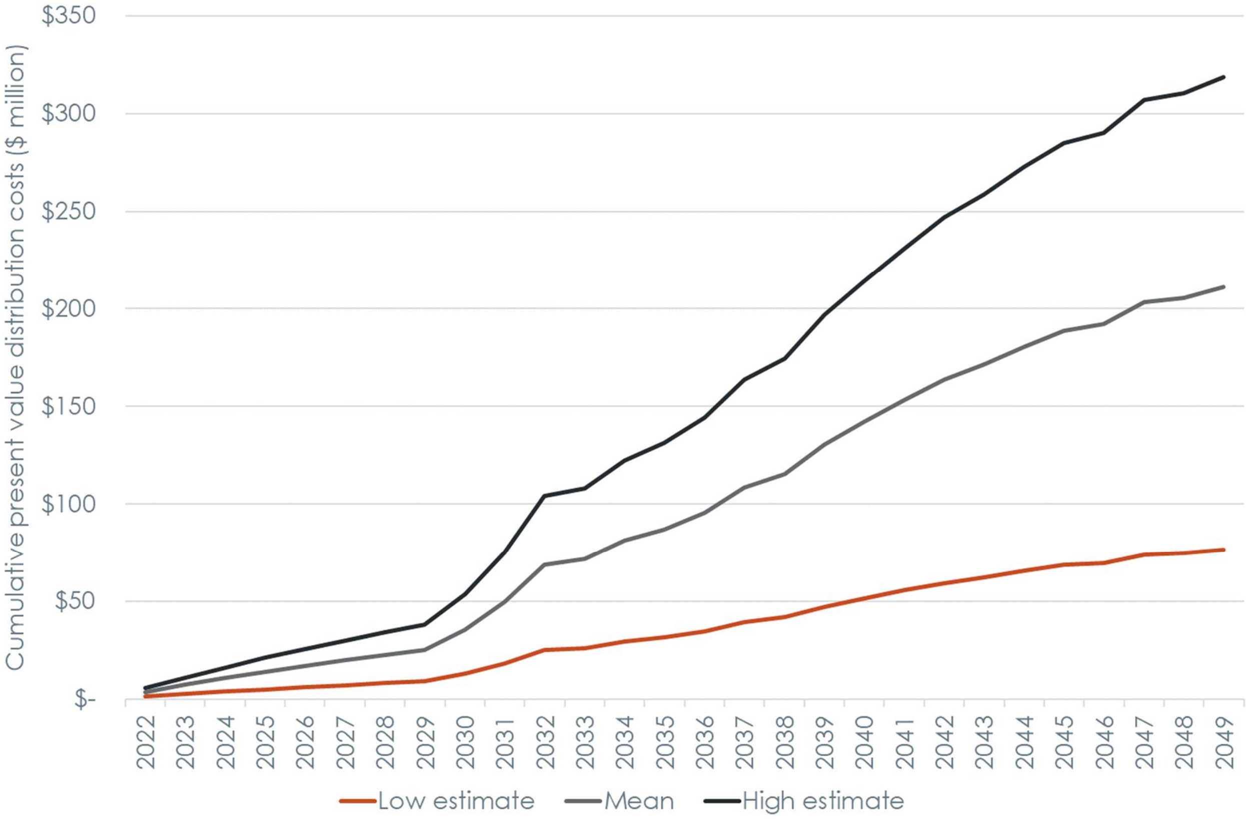
Using the approach applied in our review of the 2019 CBA, and as amended to use ratcheted peak demand (rather than peak demand), we estimate that the net present value of increased distribution network costs as a result of the proposed TPM to be:

- $77 million under the low estimate of average New Zealand distribution LRMC;
- $211 million under the mean estimate of average New Zealand distribution LRMC; and
- $318 million under the high estimate of average New Zealand distribution LRMC.

Figure 8.2 shows our estimates of cumulative changes in distribution network costs under the Authority's proposed TPM over time.

[66] Axiom Economics, *Economic review of transmission pricing review consultation paper*, September 2019, pp 94-95

Figure 8.2: Increases in distribution network costs under the proposed TPM



Source: HoustonKemp analysis based on Authority spreadsheets 'rcpd.csv' and 'aob.csv'

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