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Dear James

Transmission Pricing Review

This letter sets out Vector's views on the Electricity Authority's (the Authority's) ongoing review of the transmission pricing methodology (TPM), in light of the recent release of information papers on the cost-benefit analysis (CBA)[1] and peak charging.[2]

We understand that the Authority is not formally seeking submissions on these papers. However, given the importance of the issues, we think it is essential for stakeholder views to be considered.

This letter summarises our main concerns with the papers, which pertain to both the process being followed and the substance of the analysis. Annexes 1 and 2 present more detail on our initial assessment of the peak charging proposals and the revised CBA respectively.

Process Concerns

The Authority must take the impacts of Covid-19 and the Tiwai review into account

The Covid-19 pandemic is having severe and widespread effects on New Zealand's economy, and on the electricity market specifically. Although the Authority has undertaken a sensitivity analysis, in our view it has not accounted sufficiently for the potential cumulative impacts of the pandemic.[3] The sensitivity analysis does not contain a single mention of "Covid-19", which suggests that it was performed before the full extent of the outbreak was known.

At this stage, it is impossible to know for certain what the near-term and lasting effects of the pandemic will be on electricity demand, network investment, the cost of capital and other key factors. All of these factors are critical inputs into the various models that have been used to estimate the benefits from TPM reform. This makes it very difficult – if not impossible – to construct a robust CBA at the present time.

1 Electricity Authority, *Response to feedback on the 2019 cost benefit analysis, Revisions to CBA in the 2019 Issues paper, Transmission pricing review, Information Paper*, April 2020 (hereafter: "CBA Information Paper")
2 Electricity Authority, *Peak charges under proposed TPM guidelines Information Paper and next steps*, March 2020 (hereafter: "Peak charging Information Paper").
3 The Authority tests four sensitivities; changes in electricity generation short-run and long-run marginal costs, utility-scale battery costs, and electricity demand growth. With regards to the last of these categories (demand growth), the 'downside scenarios' were 1% or 0.5%. These do not appear to be sufficient to capture the potential reductions in demand growth that might arise from Covid-19. Moreover, the scenario used to estimate the net consumer surplus benefit assumed a 0.5% *increase* in demand above the base forecast, which seems especially inappropriate in the circumstances.

The Covid-19 situation also creates major barriers to effective stakeholder engagement. While we appreciate the Authority's effort to hold a webinar on the CBA, the limitations of this format meant that it was not an adequate substitute for an in-person conference. Stakeholders are also acutely time and resource constrained at present, which impedes their ability to undertake a detailed review of the latest iteration of the CBA.

Furthermore, the outcome of Rio Tinto's Strategic Review into the Tiwai Point Aluminium Smelter (which was due to be announced at the end of March) is not yet known. The final outcome of this review will have a major impact on the future of New Zealand's electricity market. We consider that it is not appropriate to make final decisions on its TPM review with such a significant unknown variable in the mix. Nor is it appropriate for Rio Tinto to hold the country to ransom awaiting the outcome of the TPM review before concluding its strategic review. As we have highlighted in the past, the smelter already benefits from paying the lowest wholesale prices in the country, and has received tens of millions of dollars in government subsidies in the past. As it currently stands, the TPM proposal is likely to lead to consumers picking up an even larger share of Tiwai's transmission costs.

The CBA and peak pricing proposals must be formally consulted on

Even leaving aside the uncertainties created by Covid-19 and the Tiwai review, the Authority's decision to not invite written submissions on either the peak charging or CBA information papers is highly problematic. Both papers gloss over legitimate criticisms raised by respondents to previous consultations and contain flawed analyses.

Significant changes have been made to the CBA methodology and assumptions. As a result of these revisions the estimated net benefit of the proposed reform is now half what it was forecast to be in the 2019 CBA – a drop of over $1.3 billion. And, likewise, the 2019 net benefit estimate bore little resemblance to the figures derived in earlier CBAs (in 2012 and 2016).

We acknowledge the Authority's view that the CBA is "only an aid to support deliberation and decision-making, alongside a much broader range of factors". Even so, it is concerning that despite the extensive resources devoted to CBA analyses since the TPM review was launched:

- The forecast net benefits have varied significantly over time, e.g., the 2019 net benefit estimate was more than ten times higher than the 2016 equivalent;[4] and

- Many errors have been made along the way – the 2012 and 2016 CBAs were abandoned in their entirety, and the Authority has now also acknowledged that there were major methodological shortcomings in the 2019 CBA.

In addition, the materials provided in the CBA Information Paper to explain the large changes from the 2019 CBA results are lacking in detail. The written description of the modifications to the CBA spans just 29 pages, and there is no accompanying technical paper as there was for the 2019

[4] The median estimates of net benefits from TPM reform under the different iterations of the CBA have been $173m (2012), $213m (2016), $2.7b (2019), and $1.3b (2020).

CBA[5]. We have also noticed some inaccuracies in the reporting of high-level results from the grid use model, which are discussed further in Annex 2.

In our view, the decision not to seek formal submissions on the latest version of the CBA is antithetical to good regulatory practice and to the Authority's statutory objective. Moreover, the timing of publication of the information paper (along with its brevity and lack of clarity) makes it very difficult for stakeholders to review the crucial revisions that have been made.

The Authority is yet to respond on many other important issues raised by stakeholders

Although the consultation process for the peak pricing and CBA papers is clearly inadequate, the Authority has at least set out its latest thinking on these matters. In contrast, no formal response at all has been provided to most of the other key issues raised in the submissions on the 2019 Issues Paper. Aside from the papers on peak pricing and the CBA, the only other document that has been released is the "Supplementary Consultation paper" on 11 February 2020. This paper consulted on a new (and in our view, flawed) method for determining prudent discounts, along with refinements to three other issues of relatively minor importance.[6]

Accordingly, the Authority is yet to publicly acknowledge or address a large number (perhaps even the majority) of the concerns raised in the submissions on the 2019 Issues Paper. Amongst many others, these concerns include:

- The rationale offered for the benefit-based (BB) charge – i.e., if nodal prices provide consumers with all the price signals they need, then the TPM should, logically, comprise nothing more than a non-distortionary residual charge;[7]

- The proposed application of BB charges to an arbitrary subset of existing transmission investments (an incongruity that was also highlighted by the Expert Panel on the Electricity Pricing Review);[8]

- The failure to model the impacts on consumers of allocating a share of the residual charge to generators, rather than levying the charge only on load;

- The complexity and uncertainty surrounding how the new TPM charges would be set in practice, which is almost certain to lead to greatly increased controversy and conflict between grid users, Transpower, and regulators, thus undermining the durability of the regime; and

[5] Without the assistance of a technical paper, a full review of the revised modelling would require analysing hundreds of new spreadsheets and thousands of new lines of computer code.

[6] These comprised the use of indexed historical cost (IHC) versus depreciated historical cost (DHC) in setting BB charges, the method for adjusting BB charges following plant closures and the method for adjusting the residual charge.

[7] For the avoidance of doubt, that is not a reform that we are proposing. It is simply the unavoidable corollary of the Authority's own logic.

[8] The Expert Panel stated that it was: *"…unaware of any other country undertaking retrospective reallocation of past grid investments. Indeed, some say retrospective reallocation is the principal obstacle to progress on a new TPM." See:* Electricity Price Review, *First report for discussion,* 30 August 2018, p.50.

- The possibility of pursuing alternative, more incremental reform options such as those recommended by Transpower[9] and the Lantau Group[10].

It is not clear when, or even if, the Authority plans to address these crucial outstanding issues. In our view, making a decision on the new TPM guidelines without issuing a comprehensive response to each of these matters would be a clear contravention of good regulatory practice.

Substantive Concerns

The peak charging proposals are ill-founded and contrary to industry consensus

In our view, the rationale presented in the peak charging paper for introducing a temporary congestion charge on top of the proposed benefit-based (BB) charge and nodal prices is incoherent. The Authority's analysis suggests that:

- Nodal prices would provide consumers with all the price signals that they need to see in order to make efficient short-term consumption and long-term investment decisions;

- Despite spot prices (apparently) doing the job perfectly, the BB charge would provide even more "forward-looking price information" via so-called "shadow-price signals"[11]; and

- Nevertheless, bespoke transitional congestion charges may be needed to provide yet another signal in the transition to the new TPM.

If the proposed TPM would really work in this way, then congestion would be signaled once via nodal prices, twice via the BB charge and, potentially, a third time via a bespoke congestion charge. Clearly, the resulting price signals would be far too strong. The Authority has never explained this contradiction in its logic. In our view – a perspective shared by many other respondents - these contradictions arise because:

- In actuality, nodal prices do not provide perfect short- and long-run signals – something that the Authority has previously acknowledged;[12]

- BB charges would not provide efficient supplementary "shadow prices", i.e., these signals would not work in the way the Authority claims and could well give rise to significant inefficiencies (especially when applied to existing sunk assets); and

- An LRMC-based congestion charge is not a potential complement to the proposed BB charge, it is a potentially superior substitute for it. Indeed, we note that there is near-universal

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9 Transpower, *Submission: Transmission pricing review 2019 issues paper*, 1 October 2019, pp.12-13.

10 The Lantau Group, *Review of Transmission Pricing Guidelines Issues Paper 2019*, 1 October 2019, pp.7-8.

11 Peak charging Information Paper, p.6.

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

support for retention of some form of permanent (rather than transitional) peak-usage pricing.[13]

In light of the above, we think the Authority should reconsider its position and look again at the possibility of the TPM including a permanent LRMC-based charge. If well-designed, this could potentially take the place of the BB charge.

We also note that the supporting paper by Professor William Hogan appears to be based on an incomplete understanding of the Authority's methodology and the rationales that have motivated it. Further discussion of our views on the Hogan paper is set out in Annex 1.

Our assessment indicates that the CBA remains flawed

Our initial examination of specific elements of the CBA modelling suggests that while it may have improved somewhat from the previous iteration, it still suffers from serious problems that render it unreliable as a guide to decision-making. Figure 1 below summarises our key concerns with the analysis.[14] It shows that every major modelling element exhibits potential flaws and/or gives rise to unanswered questions. For example:

- The CBA does not accurately reflect the TPM proposal, e.g., neither the grid use model nor the 'top-down' model of transmission investment include 'shadow prices' that function in the way that the Authority says that they would under its BB charge;

- Several of the headline modelling results do not appear to make sense, e.g. consumption is predicted to fall in the central scenario following implementation of the proposal, despite wholesale prices also falling (which should lead to increased demand);

- Despite assertions to the contrary, the vast majority of the $1.13b estimated benefit from 'more efficient grid use' is almost certainly a bare wealth transfer rather than an efficiency gain, i.e., it is not a genuine economic benefit;

- The modelling continues to ignore the additional distribution network and carbon-related costs that would undoubtedly flow from the proposal, and the rationale given for not including the former contradicts the methodology employed for modelling transmission and battery costs, introducing a clear upward bias to the net benefit estimate;

- The modifications made to the 'scrutiny' and 'uncertainty' models do not address the underlying problems with those analyses; and

- The Authority has not 'sense checked' either its new generation investment or wholesale price formulation models with historical data to see how well they perform at predicting past generation investments and nodal prices.

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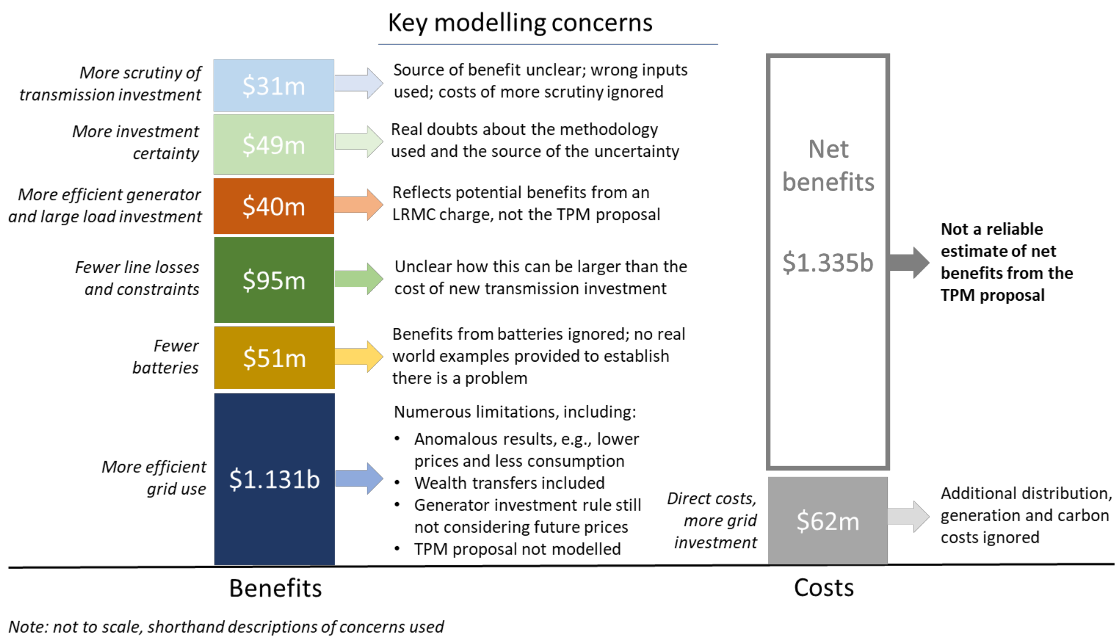
13 A review of the submissions on the 2019 Issues Paper indicates that a permanent peak-usage charge was supported by almost all respondents. The main exceptions were Meridian, Nova, and Rio Tinto.

14 Note that we have not been able to undertake a detailed forensic analysis of the modelling in light of the time and resource constraints discussed above.

In light of this, we remain unconvinced that the CBA can provide a robust indication of the likely costs and benefits of the Authority's proposed reform. Our initial assessment indicates that the true net benefit is likely to be well below the current estimate of $1.3 billion and could, in reality, be trivial, zero or negative. Clearly, this does not 'meet the bar' for implementing a far-reaching regulatory reform with significant transitional costs and a high degree of risk and uncertainty.

Figure 1: Concerns with estimated net benefit ($m, NPV)[15]



Concluding Remarks

We understand that both the Authority and the industry would like to see the TPM review brought to a conclusion. However, this must not be used as a rationale for making decisions based on faulty assumptions and analysis at a time when New Zealand is facing unprecedented economic challenges. We note that many other organisations, both public and private, are putting major projects on hold until the effects of the Covid-19 pandemic have passed or are more certain.

Given that the review has already been underway for over eight years, a further delay of 6-12 months does not seem unreasonable given the materiality of the potential impacts on the sector. This additional time would allow the industry to gain much more clarity on the impacts of Covid-19 and the Tiwai smelter review. It would also enable the Authority to further consult on and refine its CBA so that stakeholders can have full confidence in the results, and to address the many other important issues raised in the responses to the 2019 Issues Paper.

As it stands, we do not believe that the Authority can reasonably release a new TPM guideline in Q2 of this year based on its consultation process so far. In our view, doing so would contravene good regulatory practice and the Authority's statutory objective.

15 The values are taken from the CBA Information Paper.

We would welcome the opportunity to discuss our concerns with you in more detail.

Yours sincerely,

Richard Sharp
GM Economic Regulation & Pricing

ANNEX 1 – FURTHER ANALYSIS OF PEAK PRICING PAPERS

In addition to the points discussed earlier, we note that the Authority has released a paper by Professor William Hogan in support of its peak pricing analysis, as well as other aspects of the TPM proposals. In our view the report is not convincing and appears to be based on an incomplete understanding of the proposed TPM and the rationales that have motivated it.

For instance, Professor Hogan seems to be under the mistaken impression that the Authority is attempting to replicate an efficient two-part tariff (following Ramsey pricing principles) through its proposals. Specifically, Professor Hogan appears to believe that:

- The short-run marginal cost (SRMC) of grid consumption decisions would be signalled via nodal prices and losses; and
- The BB charge would be intended to do nothing more than recover the sunk costs of existing assets in a non-distortionary way – i.e., it would be a "residual charge" (to adopt the Authority's terminology).

However, that is not in fact what the TPM proposals entail. Instead, the intention is for:

- The BB charge to provide "forward-looking price information", i.e., these so called "shadow-prices" are designed to elicit changes in behaviour, not prevent them;[16] and
- The separate residual charge to deliver up the remainder of Transpower's annual revenue requirement in a non-distortionary manner.

In other words, the two-part tariff principles that Professor Hogan cites in his report do not lend support to the Authority's position. Indeed, our reading of the report suggests that he may be unaware of the existence of the 'true' residual charge. If so, this means there is no sound foundation to his conclusions about the TPM proposal.

Professor Hogan's report also mischaracterises submitters' critiques of the TPM proposal and addresses instead a series of 'strawman' arguments. For example, Professor Hogan:

- Suggests that the principal critique of the 'shadow pricing' theory was that customers would behave 'myopically'[17] when, in fact the chief criticisms were that the shadow price signals would be difficult to predict, not reflective of LRMC differentials and susceptible to tragedies of the commons. None of these points have been refuted in any meaningful way; and
- Conflates LRMC pricing with average cost pricing and criticises proponents of the former for not understanding economies of scale[18]. In fact, LRMC charging is not necessarily synonymous with average cost pricing, and there are many different variants and

[16] For instance, at page 6 of the paper, the Authority states that: *"…the expectation of benefit-based charges associated with transmission expansion would in fact give forward-looking price information."*

[17] Hogan report, p.8.

[18] Hogan report, p.9.

applications of the latter. Professor Hogan himself also ignores the crucial impacts of economies of scale when he suggests (incorrectly, in our view) that nodal prices can deliver perfect price signals.

Consequently, there is no sound basis for Professor Hogan's sweeping conclusion that:[19]

> *"The various criticisms of the Authority's proposal are either incorrect or are based on implicit assumptions that do not apply to the real transmission system".*

In our view, his report applies key economic principles incorrectly, based on an incomplete knowledge of the particulars of the TPM proposal. Consequently, it is not an adequate response to the comprehensive critiques that have been supplied by other experts throughout the review.

[19] Hogan report, p.14.

ANNEX 2 – INITIAL REVIEW OF CBA

This annex sets out a preliminary review of the revised CBA as set out in the information paper. We begin with an overview of key findings, followed by an initial analysis of each the main components of the CBA.

1. Overview of key findings

The CBA Information Paper acknowledges that there were several substantial errors in the previous 2019 modelling. In response, some significant amendments have been made to the methodology. For example, the Authority has:

- Acknowledged and sought to address the problems with its generation investment decision rule, which previously predicted that entrants would invest in unprofitable plant, driving down wholesale prices;

- Accepted and endeavoured to correct the flaws in the way the model formulates wholesale price outcomes which, previously, gave rise to invalid results unless arbitrary 'caps and floors' were placed on permitted price outcomes; and

- Admitted that its prior modelling of batteries overstated the amount of investment that was likely to actually occur under the status quo (the 'baseline' scenario) and attempted to fix it in its updated analysis.

In culmination, these and other changes have resulted in a sharp reduction in the headline net benefit estimate, from $2.7b to $1.34b.

Overall, the amendments to the CBA are a step in the right direction and address some of the concerns raised by respondents with the previous modelling. However, a number of serious problems are still evident. The model still gives rise to counter-intuitive results, and the methodology still does not accurately represent the proposed pricing approach. In particular:

- The results of the CBA are taken from a variety of different modelling 'runs' and, in culmination, there is no reason to expect the resulting combination (e.g., total demand, wholesale price movements, investment outcomes, etc.) to be coherent as a whole. Indeed, the group of modelling outputs arising from the central scenario appears to be inconsistent with the underlying rationale for the proposed reform as it shows a fall (rather than a rise) in total consumption following removal of the RCPD charge;[20] and

- Neither the grid use model nor the 'top-down' model of transmission investment include 'shadow prices' that function in the way that the Authority says that they would under its proposed BB charge.

[20] A major rationale for the proposed reform is that the RCPD charge is currently too strong and is inefficiently throttling consumption during peak periods. Consequently, one would expect the modelling to show an increase in overall consumption once the RCPD charge is removed.

Furthermore, our preliminary review suggests that specific elements of the technical modelling contain errors that inflate the net benefit estimate and render the analysis unreliable. For example:

- Despite assertions to the contrary, it is clear to us that the vast majority of the $1.13b estimated benefit from "more efficient grid use" is a wealth transfer from generators to final consumers, rather than an efficiency gain;

- The net benefit now includes a $60m sum from "grid investments brought forward"[21], which is difficult to understand because if those net benefits were truly on offer then the investments in question would be expected to occur regardless of whether the Authority's proposal is implemented;[22, 23]

- The modelling does not include any incremental distribution or carbon costs, which would almost certainly be expected to result from an increase in peak demand. The Authority's justification that including distribution costs is unnecessary because the assessment has been made at a Grid Exit Point (GXP) does not make sense in our view;[24]

- The modelling of benefits from "improved scrutiny of grid investments" and "improved certainty for investors" continues to be problematic. The Authority has adjusted both of these models, but these changes have not addressed the basic concerns raised by respondents previously. The changes made to the uncertainty modelling are also not clearly described in the CBA Information Paper; and

- As we noted earlier, the modelling ignores the effect that the Covid-19 pandemic is widely expected to have on New Zealand's economy more generally and on the electricity market specifically. The pandemic makes it very difficult to know what will happen to electricity demand, generation investment, and battery investment, given the broader macroeconomic impacts of the outbreak and the uncertain government response.

If these additional components were remedied robustly, then, in our view, the net benefit could well be either insignificant, zero or negative.

2. The grid use model

The grid use model remains the source of the great majority of the estimated net benefit ($1.24b[25] of $1.34b estimate at the median – approximately 93%). This revised edition of the model appears to be somewhat better than its predecessor. However, as we explain below, it remains flawed and the problems with the model have very large impacts on the overall CBA calculation given the vast

21 Calculated as the benefits from lower losses and constraints less the investment costs.

22 Or, alternatively, if that transmission investment (under the proposal) is supplanted by the $51m in battery investment that the Authority is modelling under the status quo, then it is unclear why comparable improvements in losses and constraint excesses would not be achieved by those more localised assets.

23 The $60m is the difference between the estimated increase in transmission costs (of $35m) and the decrease in losses and constraints (of $95m). One difficulty with these values is that they come from different scenarios.

24 Specifically, the Authority asserted that any additional distribution costs would have been factored into the demand response assumptions used in its grid use modelling. In other words, that response was muted somewhat by distribution consumers' expectations that rising peak demand would have increased distribution charges. It is not at all clear how this has been captured in the modelling.

25 Calculated as the sum of $1.13m from more efficient grid use, $51m from more efficient investment in batteries and $60m from net transmission benefits, less $1m efficiency cost of the price cap.

size of the forecast benefit from more efficient grid use.

2.1 Mixing and matching of modelling outputs

The CBA Information Paper states that four policy scenarios have been examined, representing alternative potential TPM reforms, including the Authority's preferred option.[26] Various sensitivities have also been run on each of these policy scenarios.[27] This was achieved by re-running each policy scenario 113 times with different combinations of changes in four inputs – namely, the SRMC and LRMC of generation, demand growth and battery costs. For example, one run might assume that the SRMC and LRMC of generation are 2.5% higher and 5% lower, respectively, demand is 1% lower and battery costs are 10% cheaper. Another run might involve slightly different tweaks, and so on.

Each of the 113 runs produces a variety of outputs for key metrics such as the change in consumer surplus, total transmission costs, interconnection revenue and battery investment. However, the way in which these metrics are combined is problematic. Specifically, for each measure, the Authority selects the 'unweighted median' output from the 113 model runs.[28] For example, its $1.131b estimate of the change in consumer surplus is the 57th highest value, i.e., the median estimate from the 113 model runs.

Suppose for the sake of argument that the median value was the output of run number 80 (to pick a random number between 1 and 113). The potential problem with this approach is that when the Authority comes to select its estimate of, say, the change in battery investment costs, the 57th highest value may be from a completely different run, e.g., number 23 (to pick another random number between 1 and 113). The same will apply for the estimates of interconnection revenue, total surplus, transmission costs and so forth. All those key outputs could be produced from a unique scenario and, when they are all put together, there is no reason to think that they will be coherent or consistent.

In our view, this CBA methodology is somewhat analogous to attempting to bake a chocolate cake by employing the following approach:

- Finding 113 recipes that all include the same basic ingredients (e.g., sugar, butter, eggs, cocoa, baking powder, flour and milk) but in different proportions;
- Taking the 'median' quantities of each of the individual ingredients from those 113 recipes, i.e., the 57th highest quantities of butter, eggs, sugar, etc.; and
- Combining the resulting ingredient quantities – each of which may have been taken from a different recipe (25g of butter, 1 cup of flour, etc.) – to produce the cake mix.

Clearly, there is no reason to be confident that the resulting mix will rise to produce a tasty cake. Instead, there is every chance that those 'mixed and matched' ingredients will not work together

[26] CBA Information Paper, paras 2.10-2.16.

[27] CBA Information Paper, para 2.18.

[28] To that end, it is unclear why the Authority ultimately preferred the 'unweighted median' over alternatives.

at all and result in something inedible.[29] The way in which the outputs from different scenarios have

been interspersed to produce the CBA results could be just as troublesome, i.e., there is no reason to think that the combined outcomes would be consistent or coherent. Indeed, as we explain below, some of the results seem quite anomalous.

2.2 Counterintuitive modelling results

The results of the grid use modelling are difficult to reconcile with the basic narrative of the TPM proposal. The foundation of the Authority's 'more efficient grid use' benefit is its belief that the RCPD price signal is currently too strong, thereby inefficiently reducing consumption during peak periods – firstly by shifting some consumption from peak to off-peak periods (a 'demand switching' effect), and secondly by reducing overall consumption (a 'demand reduction' effect). One might therefore expect that, relative to the status quo, the TPM proposal should result in less investment in batteries and more consumption overall.[30]

However, that is not what the modelling reveals in the headline scenario of $1.34b net benefit. In that scenario, forecast peak prices are generally lower, battery investment is falling (as expected), but total consumption is *also* lower. This is difficult to explain from an economic perspective and seems at odds with the fundamental rationale for the proposal. We have not been able to identify a straightforward explanation for why removing a peak price signal that is supposedly 'too strong' would result in a fall in demand – and the CBA Information Paper does not offer any obvious rationale.

Imagine, for the sake of argument, that the Auckland Harbour Bridge had a toll that was highest during the morning and evening rush hours. And suppose that NZTA believed that the 'peak' toll (during rush hours) was too high and unduly discouraging motorists from using the bridge during those busy morning and evening periods. If it released a CBA that suggested that reducing the peak toll and increasing the off-peak tolls would generate more than $1b in benefits (over thirty years) from 'more efficient bridge use', but that total traffic movements would *fall* over the period, it would be viewed with skepticism.

The fact that the revised grid use model has produced such a counterintuitive outcome (at least, in the headline scenario) suggests to us that there may be problems with the CBA methodology and/or assumptions. As we elaborate in the remainder of this section, this becomes even more evident when specific elements of the CBA are examined.

2.3 The modelling fails to incorporate 'shadow price' signals

In addition to the counterintuitive modelling results, there is also the more general problem that the grid use model still fails to represent faithfully the way the Authority has said that its methodology

[29] Furthermore, in this analogy each of the 113 individual recipes is assumed to be a viable way of baking a cake, i.e., each of the 113 combinations of ingredients 'makes sense'. We have not yet examined whether the 113 'runs' that the Authority has performed are similarly internally coherent. It could be that even those individual runs themselves are problematic, i.e. a 'bad recipe' for cake.

[30] This overall increase would result because any reductions in consumption that resulted from switching from off-peak and shoulder periods would be expected to be more than outweighed by the increase in demand in peak periods. Indeed, that is the fundamental premise of the grid use modelling.

would function in practice. Specifically, the Authority is still maintaining that the proposed BB charge would provide 'shadow price' signals to which customers would respond by efficiently, 'rationally self-rationing'. This remains the position in the peak charging Information Paper.[31]

However, the grid use model does not incorporate the types of 'shadow prices' that customers would – according to this theory – be recognising and responding to. In fact, it does not include 'shadow prices' at all.[32] Accordingly, in our view the CBA model is not based on the actual TPM proposal.

2.4 New generation investment decision rule

The CBA Information Paper accepts that:[33]

> *"…the decision rule used in the grid use model could be more nuanced. It did not adequately account for the effect of new generation investment in suppressing wholesale electricity prices. Some generation investments were modelled as taking place when it was unclear whether these investments would be profitable."*

The revised CBA now forecasts that:

- The total amount of new generation investment that would occur under the proposal would be 920MW – considerably less than the 1-1.5GW forecast previously. The NPV of the investment cost has fallen even further, from $5.4b to $1.7b over 30 years;

- The total amount (in MW) of new generation investment would rise if the proposal is implemented, i.e., 920MW vs 883MW under the baseline scenario (note that the CBA Information paper states – wrongly – that generation investment would fall[34]);

- The total amount of generation investment would likewise be higher in dollar terms under the proposal: $2.08b vs $1.86b; and

- The estimated benefits from 'more efficient grid use' have fallen from $2.58b to $1.13b, i.e., by $1.45b or 56%.[35]

These are significant changes. However, the description of the amendments to the generation entry rule spans only three sentences in the Information Paper:[36]

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31 Peak charging Information Paper, p.6.

32 Somewhat inexplicably, as we shall see shortly, the Authority *does* appear to include shadow prices (albeit the *wrong ones*) in its 'top down' model of 'more efficient investment in generation and large load'.

33 CBA Information Paper, para 5.3.

34 The CBA Information Paper states (para 5.8): "In the revised results, generation investment totals 838MW under the proposal and 885MW under the baseline". The problem here is that the scenario to which the Authority is referring was not the one used to estimate the net benefit from its grid use modelling (i.e., the $1.131b figure that it references repeatedly). We have therefore focussed on the scenario that *was* used to generate that net benefit, which is described in shorthand as: "s_1.0_1.05_0.01_0.9".

35 Note that this drop is not solely attributable to the changes in the new generation investment decision rule – other elements of the grid use model have also changed substantially, as we shall see shortly.

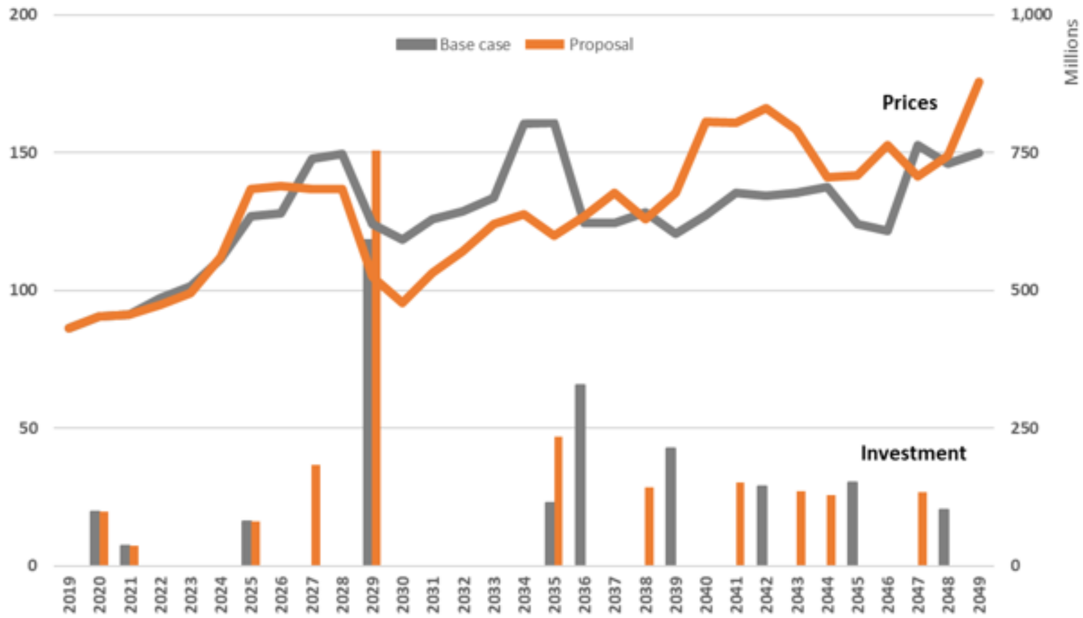
36 CBA Information Paper, paras 5.6-5.7.

> *"Under the revised decision rule, earnings on new generation investments are* ***based on the price investors would receive once their capacity and offers are added to the market****. This amendment removes the need for assumptions about the number of generation investments that would occur in a single year. Instead,* ***a sequential decision rule is used****, where multiple generation investments in a single year can only occur* ***if all investments are profitable after accounting for the collective effect of these investments on suppressing wholesale electricity prices****."* [emphasis added]

In our view, this explanation is inadequate considering the magnitude of the changes that flow from it. The bolded passages are crucial – yet they could be interpreted any number of different ways.

There is also an obvious problem with the 'sequential' decision rule. Specifically, although the rule has rightly been adjusted to account for the potential impact that entry may have on wholesale prices, it does not appear to account for the fact that investors look to the future before investing, not the present. From what we understand, the rule assumes that prospective investors would consider the forecast impact of their entry on demand and wholesale prices in the single year in which new generation enters. This means, for instance, that a forecast spike in wholesale prices from rising gas costs is only considered by generators making decisions when the spike occurs, rather than pre-emptively. This is illustrated in the figure below, which shows clearly that the model forecasts generation investment as lagging wholesale price increases.[37] This does not reflect the way in which investors make decisions in the real world. Rather, when deciding whether to build new plant, investors will consider potential prices (and returns) in future years. Looking only at current prices would be likely to lead to poor investments (e.g., if prices were expected to fall in coming years) and missed investment opportunities.

Figure 2: Average wholesale prices and generation investment



[37] The figure combines generation prices and investment sourced from the 's_1.0_1.05_0.01_0.9aob', 's_1.0_1.05_0.01_0.9rcpd', and 's_1.0_1.05_0.01_0.9generation_investment' files.

The entry rule also seems[38] to assume that investors expect all capacity to be dispatched when deciding whether or not to invest. In reality, a generator offering into the market risks not being dispatched at full capacity – something that any prospective investor would weigh up when deciding whether to enter.

If the generation entry rule were to capture accurately these important nuances, it is almost certain that the projected generation (and resulting net benefits) would differ from the current model. It is unclear why these limitations were not recognised and addressed, given that the shortcomings were highlighted by multiple parties in their submissions on the 2019 CBA.

The CBA webinar did not provide much in the way of additional clarity on these matters. For example, the Authority:

- Was unable to explain why it had not used MBIE's LRMC estimates – or how/why its estimates differed; and

- Did not provide a convincing explanation for why ostensibly high-cost thermal plant had been included in its new investment stacks.

The webinar also exposed some further problems and anomalies. For instance, the additional thermal generation that is now forecast to arise from the proposal would produce additional carbon emissions, yet these costs have not been considered in the CBA. The Authority also confirmed during the webinar that it has not tested to see how well its decision rule performs at modelling actual historical market outcomes, and conceded that its methodology could fare quite poorly in any such 'sense checking'.[39] This pessimism appears to have been justified, based on our initial high-level review of the underlying modelling.

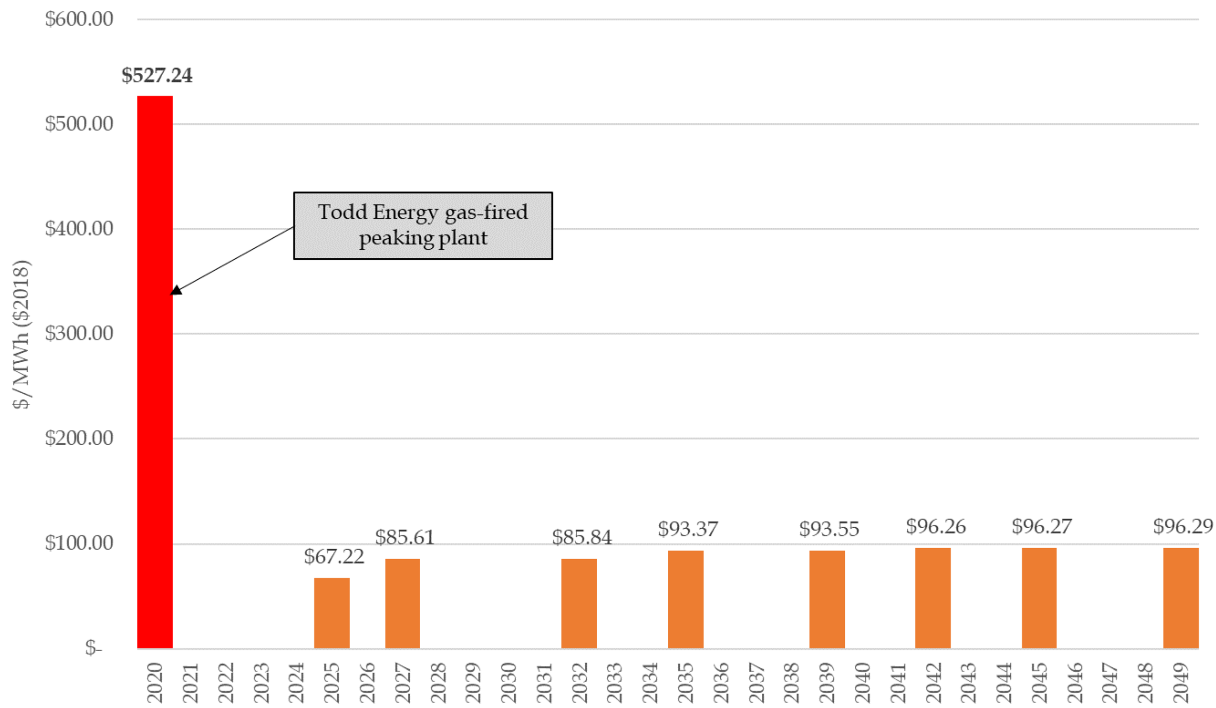
For example, the figure below depicts the estimated LRMC of the new generation plant that the Authority predicts would be built under its proposal. There is a clear outlier: the gas peaking plant that Todd Energy is scheduled to open in Taranaki this year. The Authority estimated the LRMC of this plant at $527.24/MWh[40] – more than five times higher than the LRMC of the next most expensive new plant, according to its modelling. When the new investment rule was applied to this plant, it appears that it did not pass, i.e., the model indicated that plant would not be profitable and would not be constructed.

[38] This particular concern needs further investigation to confirm. It may be that, within the Python code, the volumes assumed have been adjusted somewhat to account for this risk.

[39] Specifically, the Authority acknowledged that the generation investments that its approach would have predicted if it had been applied as at say, 1999, might have borne little resemblance to the plant that was actually build in the ensuing twenty years.

[40] These LRMC figures were obtained from: the "grid use model > output > central > plant investment" spreadsheet.

Figure 3: LRMC of forecast generation plant investment



Of course, because the plant *is* being built, the Authority had little choice but to set aside its investment rule and include the plant in its CBA scenarios. However, the fact that it had to work around its modelling in order for it to produce an outcome that reflected reality is troubling. So too is the discrepancy between the LRMC estimate for the Todd plant and the others that the model is projecting to be built, which seems too large to be plausible. These results suggest to us that something has gone awry with the LRMC calculations and/or the new generation entry rule.

Finally, as we noted earlier[41], the CBA Information Paper reports results for a scenario that was not actually used to estimate the $1.131b net benefit from 'more efficient grid use'. This leads to

inaccurate statements in the paper about the forecast impacts – e.g., the paper states that generation investment would be lower under the proposal than the baseline (838MW vs 885MW) when, in fact, it would be higher (920MW vs 883MW). This causes additional confusion and makes it difficult to comprehend the logic for the modelled outcomes.

2.5 Wholesale price formation

The CBA Information Paper concedes that:[42]

> *"…the wholesale electricity price formation module of the grid use model warranted revision. Wholesale electricity price formation was assumed to be a function of short-run marginal costs of generation. This affected estimates of the profitability of generation investment and (given also the investment rule*

[41] See: footnote 38.

[42] CBA Information Paper, para 4.2.

> *used) notional floors and caps on wholesale electricity prices had to be used to prevent very high or very low modelled prices."*

In our view, this is understating the problem with the earlier modelling. For example, removing the arbitrary caps and floors on generation prices in the previous CBA produced a series of wholesale prices that delivered an increase in consumer surplus of $2 octillion (i.e., $2 followed by 27 zeros) under the TPM proposal[43] – clearly an impossible outcome.

The Information Paper again provides only a brief explanation of the revisions made to the model of wholesale price formation. It states that the Authority has:[44]

> *"…amended its model so that formation of wholesale electricity prices is now based on the intersection of demand by time-of-use and typical annual offer curves **based on offers from grid-connected generators for the 3 years 2015-2017** (thereby also accounting for the value of water). Offer curves are measured relative to short-run marginal costs, so the curves shift up or down as short-run marginal costs change over time. There is now no need to use floors and ceilings."* [emphasis added]

As with the generation investment rule, we think this description is insufficiently detailed considering the magnitude of the change. We have not had time to review the underlying modelling but, on its face, there is no obvious reason to think that three years' worth of offer data would be representative of the ensuing thirty years' worth of wholesale prices. The Authority also confirmed in its webinar that it has not performed any analysis to see how well its approach performs at modelling actual historical wholesale market prices, which would be a useful 'sense check' on the methodology.

2.6 Other investment modelling

The Authority has made some significant changes to the way it forecasts battery and transmission investment in the CBA, while continuing to maintain that it is not necessary to model impacts on distribution costs. We step through these changes below and highlight the inconsistent ways in which costs and benefits have been measured in these different parts of the electricity supply chain.

Battery investment

The Information Paper acknowledges that:[45]

> *"…the battery investment modelling used for its 2019 CBA did not account for constraints on load shifting and was not based on detailed modelling of battery operation by time of use. It also used a stylised, rather than an optimising, investment rule."*

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[43] Axiom Economics, *Economic review of transmission pricing review consultation paper, A report for Transpower*, September 2019, p.164.

[44] CBA Information Paper, para 4.3.

[45] CBA Information Paper, para 3.2.

Following revisions to the battery assumptions, the CBA now forecasts that total investment in batteries under the status quo would be ~300MW (down from the ~3,000MW assumed in the previous CBA). The total battery investment cost that the proposal is estimated to avoid (relative to the status quo) is accordingly much less – $51m, down from the $201m assumed previously.

The direction of these changes appears to be appropriate. However, it remains unclear whether there are any real-world examples of grid-connected batteries being installed solely to avoid transmission charges. Given the noticeable impact that projected battery investment has on generation investment under the base case, these sorts of practical examples would be a useful sense check on the plausibility of the modelled outcomes.

The revised CBA also includes as a benefit the $51m in additional *costs* that would be avoided if the battery investments did not proceed, but does not consider the *benefits* that would also be foregone, e.g., to reliability, security of supply, quality of supply and to transmission investment requirements (which would be likely to be lower).[46] In its webinar, the Authority also confirmed that it had not considered the potential benefits battery investments would deliver as a source of 'back-up' power. This in itself is problematic, but as we highlight below, it is also inconsistent with the approach taken to assessing other categories of investment.

Our initial – albeit only high-level – examination of the battery investment modelling itself has also shown that the $51m in estimated avoided costs of battery investment is taken from a different scenario run to that used to estimate the $1.13b in net benefits from more efficient grid use. This creates an obvious inconsistency in the modelling as we explained earlier, i.e., there is no reason to think that those two outputs are coherent in combination (especially when set alongside others such as transmission investment, interconnection revenue, and so on).[47]

Transmission investment brought forward

The methodology for calculating the value of the transmission investment that would be brought forward under the TPM proposal has also been modified. The model now forecasts that $35m in transmission investment would be brought forward relative to the status quo – down from $188m in the previous iteration. Although we have not reviewed the detailed elements of these changes to the grid use model, the new results appear to contain an anomaly.

Namely, the modelling suggests that the additional $35m of transmission investment forecast under the TPM proposal would deliver $95m in benefits from lower losses and constraints (i.e., an overall net benefit of $60m).[48] However, under the status quo, that transmission investment could well be supplanted by the $51m in additional battery investment that the model is forecasting. Those batteries would presumably give rise to loss and constraint savings – relative to the situation in which those assets did not exist. Yet, as we indicated earlier, the CBA currently ignores these

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[46] In the same way that avoided investment *costs* should be included as *benefits*, so too should any avoided battery *benefits* be included as *costs*.

[47] Specifically, the $51m is taken from scenario 's_1.025_1.0_0.0_1.0', while the grid use benefits are taken from scenario 's_1.0_1.05_0.01_0.9'. Under the first scenario, generation short-run and long-run marginal costs are assumed to be 2.5% higher and 5% lower, respectively, demand 1% lower and utility-scale battery costs 10% cheaper. It is consequently unsurprising that battery investment differs between the two scenarios.

[48] CBA Information Paper, para 6.6.

benefits of batteries in its CBA and counts only the avoided investment cost. It is possible that the net impact on losses and constraints could be negligible once the benefits from battery investment are taken into account.

Indeed, if it were not for this anomaly, it is difficult to see why the model would forecast such a large net benefit from transmission investment brought forward. If such a benefit were available, one would expect Transpower to also bring forward the investment under the baseline scenario.

Additional distribution costs continue to be ignored

Several respondents to the 2019 Issues Paper highlighted that distribution networks would need to undertake additional network investment if the TPM proposal were implemented, to meet the forecast increase in peak demand. However, the Authority has not attempted to model the impact of its proposal on distribution networks – its assessment "ends at the GXP". This is in contrast to the modelling of transmission, generation and battery investment, which receive close attention throughout the CBA.

The Authority's rationale for "stopping at the GXP" and, in effect, ignoring the impacts on distribution networks is two-fold. Namely, it suggests that:

- The impacts of additional peak usage on distribution networks would be hard to predict and could vary from network to network; and

- The costs of any additional distribution investment prompted by its proposal would give rise, on average, to benefits of an identical magnitude.

In our view, this is not a satisfactory response, because:

- It is unrealistic to assume that additional peak demand would not give rise to additional distribution network costs, on average – especially when the CBA is forecasting that *transmission* costs would be brought forward ($35m in its new CBA);

- The model does estimate the impact of additional peak demand on future transmission network costs – it is not clear why it would be any more difficult to also model impacts on the distribution network; and

- If it really was the case that any increase in distribution costs would give rise to equal benefits, then is it unclear why the Authority would be pressing EDBs to reform their tariffs, e.g. by moving towards more time-of-use or demand-based pricing to signal peaks.

The approach to modelling distribution costs also creates contradictions in the CBA methodology. If the CBA assumes that any $1 in additional distribution costs would give rise to $1 in benefits on average, then why not adopt the same assumption for batteries, transmission and generation investments? The current approach introduces a clear bias into the model. In our view, there are compelling reasons to think that additional distribution costs would exceed the additional benefits, since that investment would only be made to address reliability or security of supply concerns brought about by the additional peak demand.

Stepping back, it seems counterintuitive for the CBA to essentially 'cut off' the network at the GXP in its model. Most electricity in New Zealand is consumed behind the GXP (i.e., at the distribution network level), and so in our view it is difficult to justify ignoring this crucial element of the interconnected system. We consequently remain of the view that additional distribution costs could be significant and should be counted.

2.7 Inconsistent treatment of costs and benefits across the supply chain

There is a material inconsistency in the way the costs and benefits of the TPM proposal have been estimated across different parts of the electricity supply chain. Specifically:

- For battery investment, the $51m in avoided investment costs is modelled separately, but the benefits of those investments are ignored;
- For transmission, the $35m in additional investment costs is modelled separately, and is said to give rise to $95m in additional benefits (which is also modelled); and
- For distribution, the costs and benefits are assumed to cancel each other out, and therefore neither is modelled.

However, as the table below highlights, despite these inconsistencies in approach there is a consistent impact on the outcome. Namely, on each occasion the approach that has been selected serves to *increase* the estimated net benefit from the TPM proposal.

Table 1: Inconsistent treatment of costs and benefits

Category	Costs	Benefits	Impact on net benefit estimate
Batteries	Included ($51m)	Ignored	**Increases** ⇧
Transmission	Included ($35m)	Included ($95m)	**Increases** ⇧
Distribution	Ignored	Ignored	**Increases** ⇧
		Overall effect on CBA result	**Biased upwards**

These contradictory approaches to different categories of investment introduce a clear upward bias into the CBA. In our view, this undermines the integrity of these elements of the modelling and the resulting estimates.

2.8 The benefit estimate still includes wealth transfers

The Information Paper states that the estimated grid use benefit – now $1.13b – still does not contain any wealth transfers:[49]

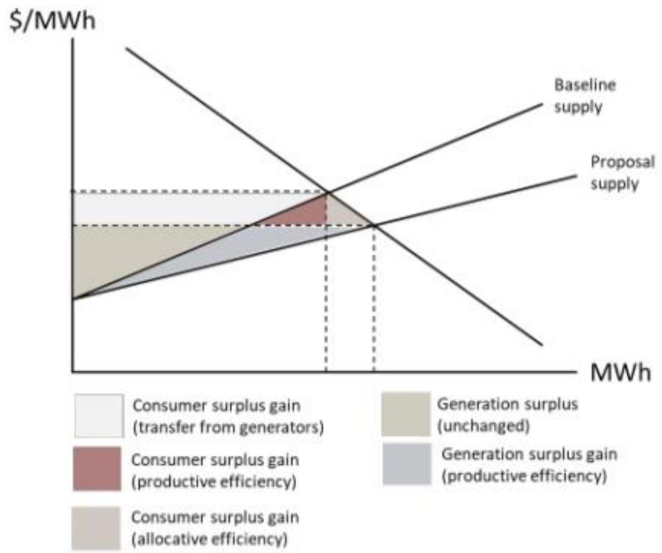
49 CBA Information Paper, para 9.2.

"The Authority considers the CBA does not treat transfers as benefits. ***Lower costs (and so lower wholesale electricity prices) are from efficiency gains, which are benefits****. If new generation investment lowers wholesale electricity prices, then consumers will likely benefit from lower prices and higher consumption. Of course, existing suppliers may lose profits and market share, but that is not a cost but an efficiency gain that should be counted as a benefit."* [emphasis added]

In our view (which was shared by many respondents on the previous CBA), this contention is unsound. As a matter of simple 'economic geometry', it is not feasible for the types of changes the Authority is forecasting to produce such a large net benefit number unless the majority of it consists of a wealth transfer. That is because the proposal is predicted to have relatively little effect on the total *quantities* of electricity that are consumed. Instead, the chief impact would be on the *prices* at which that electricity is sold. Specifically, in the scenario that gives rise to the $1.13b estimate (which we discussed earlier), the CBA forecasts that:

- Wholesale prices would decrease, on average, for the next 20 years;
- The SRMC of operating generation plant would fall on average;
- The total amount of generation (in MW) and the amount of capital investment (in $) in generation would increase; and
- The total amount of electricity generated and consumed (in MWh) would fall, but only by a small amount.

As we explained earlier, this combination of outputs seems counterintuitive – it is unclear why a drop in average wholesale prices would reduce consumption, overall. However, even leaving aside this anomaly, the changes to price and quantity are not suggestive of the large efficiency gains that are forecast in the CBA. It is possible that the Authority's assertion that its forecast price reduction would deliver *only efficiency gains* has been influenced unduly by the figure contained in a report prepared by NERA on behalf of Meridian, which appeared prominently in the CBA Information paper (see adjacent chart).



Specifically, we believe the Authority may be assuming that the area labelled "consumer surplus gain (transfer from generation)" is roughly equal to the area labelled "generation surplus gain (productive efficiency)". Although they appear to be about the same size in this stylised chart, they would not be comparable in reality, or in the grid use modelling, given the shape of the offer curve presented during the webinar.

Despite the simplicity of the NERA figure, it is unclear which curves are shifting – or in which directions – in the model. Indeed, for the reasons discussed earlier, it is not obvious what combination of movements would produce reduced wholesale prices coupled with lower demand (in MWh). What we can say for certain is that what is happening in the Authority's model bears no direct resemblance to NERA's chart, i.e., there is no neat 'tilting outwards' of the long-run supply curve. Any effects would be far messier and happening at the outer limits of the generation offer stacks. It follows that most of the areas in NERA's chart would be very small.

In other words, there is unlikely to be a large area corresponding to "generation surplus gain (productive efficiency)". As we noted earlier, this is a necessary condition for the Authority's contention (i.e., that there are no transfers wrapped up in its net benefit estimate) to be true. Instead, the major change will be the increase in consumer surplus arising from wealth transfers to final customers from generators. This is all laid out transparently in NERA's own analysis for Meridian, which states: *"we are not disputing that the Authority's energy price effect includes transfers and that these might be large"*.[50] Moreover, NERA's estimate of the net benefits from more efficient grid use was $50.8m[51] – more than a billion dollars lower than the Authority's latest estimate[52]. In our view, this can only be explained by the inclusion of wealth transfers in the latter.

The Authority was unable to cast much light on these elements of its modelling in its webinar. For example:

- It stated that it had not examined whether the total cost of generation would fall if the proposal was implemented and if that fall was equal to its forecast reduction in wholesale revenue, i.e., it had not checked to see whether its foundational contention (that forecast wholesale price drops stemmed only from cost reductions) was true; and

- It said that it had looked at both 'consumer welfare' and 'total welfare' changes when performing its CBA and suggested that its $1.34b 'central' net benefit estimate was somehow a product of both, which in our view does not make sense, because:
  - If it were the product of both then, by definition, some bare wealth transfers would need to have been included (otherwise it would be just a change in *total* welfare); and
  - The CBA Information paper states categorically that no transfers have been included – "*…the CBA does not treat transfers as benefits*."[53]

Our preliminary review of the modelling (without examining all the spreadsheets and code) indicates that the revised CBA continues to include the *total* change in consumer surplus (i.e., efficiency gains *plus* transfers) as a net benefit rather than, say, the change in total surplus (i.e.,

50 NERA, *2019 transmission pricing review – review of certain economic reports, Meridian Energy,* 31 October 2019, para 15 (hereafter: "NERA report"). Given that NERA has stated so unambiguously that the net benefit estimate contains wealth transfers, we do not understand the basis for the Authority's assertion that: *"NERA disagrees with some submitters suggesting the Authority counts transfers as benefits."* (Information Paper, para 9.5)

51 NERA report, Table 2.

52 Note that this $50.8m estimate was not robust, because it was the product of the previous, flawed generation investment decision rule – something that NERA failed to appreciate when suggesting the revised figure. However, this serves simply to highlight the absurdity of the Authority's contention that it has not included any wealth transfers.

53 CBA Information Paper, para 9.2.

efficiency gains alone).[54] However, a more comprehensive examination of the modelling would be required to isolate and identify the precise magnitude of the wealth transfers. That analysis is not straightforward to undertake because of the aforementioned problems surrounding the way the Authority has selected its scenarios.

2.9 Additional carbon costs have not been considered

The Authority has also not addressed the concerns expressed by many that additional consumption during peak periods could lead to a variety of outcomes that run contrary to New Zealand's broader decarbonisation objectives. Those concerns are arguably even more pressing in the revised CBA.

That is because, as we noted earlier, the new modelling is forecasting that there would be significantly more high-cost thermal plant if the TPM proposal were implemented. Naturally, if true, that would increase carbon emissions. Accordingly, we remain of the opinion that the additional carbon costs that would arise from the proposal would be significant and should be considered.

3. Top-down modelling

The three 'top-down' models in the CBA account for $120m in benefits.[55] The CBA Information Paper concedes that there were problems with elements of all of these models in the prior CBA. However, in our view it does not acknowledge the full extent of those shortcomings, and the changes made do not properly address them. The models consequently remain unreliable, for the reasons discussed below.

3.1 More efficient investment in generation and large load

The estimate of the benefits from 'more efficient investments in generation and large load' is much the same as it was previously – $40m (down from $43m). The source of these benefits is said to be generators and large load responding to the 'shadow prices' provided by future BB charges by investing in superior (lower cost) locations.

In our opinion, there continues to be two problems with this modelling:

- In its most recent papers, the Authority has shifted its previous position and claimed instead that nodal prices and losses are the only signals that market participants need to see in order to make efficient consumption and investment decisions. Assuming this is correct (which, in our view, it is not), why would there be any additional 'signalling' benefits provided by the BB charge?

- Setting this more general problem aside, the Authority has modelled the BB 'shadow prices' by using a rudimentary measure of the LRMC of transmission, which does not reflect the BB

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[54] The Authority has used the same consumer surplus 'equation' as it did in its 2019 CBA.

[55] $40m from 'more efficient investment in generation and large load' *plus* $49m from 'more efficient grid investment (scrutiny of investment proposals)' *plus* $31m from 'increased certainty for investors.'

charges that customers would be paying, in practice. The top-down modelling therefore does not provide an accurate representation of the proposed pricing approach.[56]

What the modelling *might* show – albeit inadvertently – is a source of potential benefits that could be obtained by implementing an explicit LRMC-based charge based on estimated differentials in the LRMC of transmission across regions. This would be somewhat ironic, because the Authority has consistently maintained that introducing an LRMC charge is unnecessary and would be a retrograde step.

3.2 Benefits from increased scrutiny

In our view, the Authority's response to the various critiques of its methodology for estimating benefits from "increased scrutiny" of grid investments is inadequate. The Information Paper still does not provide a cogent account of why introducing a BB charge would result in different, superior investment decisions being approved, considering the heavy scrutiny that is applied already by the Commerce Commission (the Commission). In our view, the quantitative point estimate provided for 'scrutiny gains' is irrelevant, because:

- It followed scrutiny from the Commission, not third parties; and
- It came from a period in which Transpower was charging customers under the current TPM, i.e., there was no BB charge in place.

The Commission will continue to perform a similar oversight role for future transmission proposals. Hence, the estimate tells us little or nothing about the *incremental impact* on the Commission's oversight role of introducing a BB charge. To our knowledge, the Authority has no relevant data to assist it on this point.[57]

More generally, the Authority has not explained why introducing a BB charge:

- Would incentivise parties to 'come out of the woodwork' and engage more vigorously and constructively in new investment approval processes. We note that better-resourced parties already engage on major investment projects (e.g., the North Auckland and Northland (NAaN) approval process spanned years and prompted many submissions), while smaller organisations tend not to even participate in consultations on matters of far greater financial significance, such as Transpower's regulated Weighted Average Cost of Capital (WACC);
- Would result in parties providing 'superior information', given that customers are unlikely to support an investment just because it is 'good for the market' – they will only care about minimising their own transmission charges, whether they benefit from an investment or not. In our view, the proposal could in fact incentivise substantially more unconstructive

[56] In other words, the Authority is, once again, 'test driving the wrong type of car'.

[57] During its webinar, the Authority indicated that it had found 'additional datapoints' to add to the single observation upon which it had relied previously. It did not say what they were or how it had incorporated them into its model. However, it did indicate that they were found by looking at the scrutiny applied by the Commission to Transpower's past investment proposals. It follows that these additional data (whatever they may be) are equally uninformative regarding the incremental effect of adding a BB charge.

opposition to *all* investments – both 'good' and 'bad' – since parties will be apprehensive about being 'locked-in' to paying BB charges for decades;

- Would make the Commission's oversight role any easier, since:
  - For the reasons set about above, it will always have to 'sort the wheat from the chaff' when reviewing submissions – the TPM cannot short-circuit that process, but, in the case of a BB charge, it could make things much harder; and
  - It is undoubtedly aware of the proposed TPM reforms and, if it thought they would deliver this type of benefit, it has had eight years to put in a submission supporting the proposal – the fact it has not done so is telling, in our view.

The Information Paper does not address the full extent of these problems, and the proposed solution is therefore inadequate. In our view, the adjustments that have been made to this element of the model are arbitrary, and no compelling reasons have been provided to believe that there would be any net benefit arising from greater scrutiny of investments. Indeed, the proposal is more likely to lead to additional costs.

3.3 Benefits from increased investor certainty

The forecast benefits from 'increased investor certainty' were criticised by submitters for a variety of reasons. First, the vast majority of the uncertainty surrounding the TPM is arguably largely a result of the TPM review itself. Accordingly, it seems inappropriate to assign benefits from removing that uncertainty. This concern has not been addressed in the revised modelling. Second, the model rested heavily on two input assumptions that served to completely randomise the results – namely:

- An assumption that, under the TPM proposal, the frequency of 'significant uncertainty events' would reduce from once every ten years, to once every eleven. This assumption appeared to have no empirical foundation; and
- An assumption that the baseline level of uncertainty was '100' – this bespoke number was required in order for the model to produce a dollar value for the benefit estimate. The problem was that changing that arbitrary value (e.g., to 1, 200, 1,000 or anything else) changed the resulting benefit estimate. It therefore stood to reason that the Authority had chosen '100' as its baseline value – from the unlimited potential candidates – because the benefit it produced must have 'seemed about right'. However, if that was the case, it clearly constituted inappropriate 'reverse engineering'.

The CBA Information Paper does not address the '10/11 year' issue and remains silent on this point. That criticism consequently remains valid and serves to undermine the results. With regards to the second criticism, the Authority indicated during its webinar that it had changed the modelling so that it was no longer necessary to set an initial benchmark value for uncertainty (despite the

Information Paper itself indicating otherwise).[58] Our high-level review of the modelling confirmed that is the case.

Our review also uncovered another key change that is not discussed in the Information Paper, but which has a crucial impact on the result. Namely, one of the inputs into the previous version of this model was an assumed relationship between policy uncertainty and investment.[59] The Authority cited a single journal article that had estimated a negative relationship of 8.7% between economic policy uncertainty in the United States[60] and corporate capital expenditure (expressed as a proportion of total assets).[61]

It appears that the previous CBA assumed that this single datapoint – taken from a completely different context in another country – could be applied to New Zealand's electricity sector. In our opinion, that assumption was unsound, i.e., there was no reason to think that this estimate had any application in these circumstances. Moreover, in the revised version of the model, the input parameter has been halved, i.e., the assumed negative relationship between uncertainty and investment has been reduced from 8.7% to 4.35%. No explanation is offered – anywhere – for this adjustment.

Given that the input is taken directly from a journal article (albeit one of questionable relevance), there would seem to be no principled basis for cutting it in half. Consequently, one possible answer would again appear to lie in the *results* the model would have produced if that adjustment had *not* been made. Namely, if the value had been left at 8.7%, its estimated benefit from 'improved certainty' would have been closer to $100m, i.e., a considerable uplift on the benefit it had included in its 2019 CBA. We suspect that such a large increase was viewed as unrealistic, whereas halving the value of the input produced a more 'reasonable' estimate of $31m. If this is the case, it would be an example of reverse engineering the assumptions to achieve a specific outcome.

This inference is reinforced by the fact that the Authority has admitted that there is no strong empirical basis for measuring the effects – if any – of uncertainty. The Information Paper concedes that:[62]

> *"…**there is no strong evidence as to the right number that should be used to express existing effects of uncertainty in the New Zealand electricity market**. However, it does not then follow that this effect should be left unquantified."* [emphasis added]

If there is no objective empirical basis by which to determine the effects of uncertainty on investment then it follows that the only way to arrive at an estimate is via subjective judgement. This appears to be precisely what the Authority has done in both the 2017 CBA and its revised version, i.e., it has picked a benefit estimate that it considered to be 'reasonable'. If that is indeed the case then in our view it is not appropriate to include such effects in the CBA.

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58 The paper creates the misleading impression that the modelling *continues* to require an arbitrary benchmark value of uncertainty to be specified. At one point, the paper notes that: *"The benchmark value of 100 used to express current uncertainty could, in principle, be calibrated to any number greater than zero…"*(See: CBA Information Paper, para 8.6).

59 Electricity Authority, *CBA approach, methods and assumptions, 2019 issues paper: Technical paper, Information Paper*, 23 July 2019, p.90.

60 This was measured by reference to newspaper articles mentioning uncertainty in connection with the economy and politics; uncertainty about the future expiry of tax code provisions; and dispersion in macroeconomic forecasts of inflation and expenditure.

61 Gulen, H & Ion, M, "Policy uncertainty and corporate investments", *The Review of Financial Studies*, 29(3), pp.523-564

62 CBA Information paper, para 8.3.

Accordingly, we remain of the opinion that no compelling reason has been provided to believe that any benefit should be attributed to 'improved investor certainty'. The '10/11' year issue still remains, and the modelling inputs still appear to have been selected/calibrated in order to produce a preconceived result. More fundamentally, the principal source of uncertainty – at least over the last few years – has been the TPM review itself. Regulatory uncertainty could be reduced immediately by the Authority stopping its review and abstaining from looking at the TPM for, say, the next five to ten years.[63]

4. Conclusion

Our initial review of the CBA modelling has revealed some areas in which technical aspects of the CBA modelling appear to have been improved relative to its predecessor. However, in our view the CBA still contains serious errors and falls well short of best practice. We consequently remained unconvinced that the CBA can provide any robust indication of the likely costs and benefits of the proposed TPM reform. In our opinion, the true net benefit of the TPM proposal remains unknown – it is almost certain to be well below that forecast in the model, and could be trivial, zero or negative. Furthermore, for the reasons we set out earlier, it arguably is impossible for a robust CBA to be performed at present, given the pervasive uncertainty surrounding key inputs due to the Covid-19 pandemic and the review of the Tiwai smelter.

Therefore, as it stands, we do not believe that the Authority can reasonably release a new TPM guideline in Q2 of this year based on its consultation process so far. In our view, doing so would contravene good regulatory practice and the Authority's statutory objective. Given that the review has already been underway for over eight years, a further delay of 6-12 months does not seem unreasonable given the materiality of the potential impacts on the sector. This additional time would allow the industry to gain much more clarity on the impacts of Covid-19 and the Tiwai smelter review. It would also enable the Authority to further consult on and refine its CBA so that stakeholders can have full confidence in the results, and to address the many other important issues raised in the responses to the 2019 Issues Paper.

[63] The Authority also did not provide any clear details of the "alternative methods for calculating uncertainty" that it had examined (*see:* CBA Information Paper, para 8.7).