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31 October 2019

James Stevenson-Wallace
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By email: submissions@ea.govt.nz

Dear James

# Cross-submission: Transmission pricing review 2019 issues paper

Transpower appreciates the Electricity Authority's (Authority's) decision to seek cross-submissions on the 2019 transmission pricing methodology (TPM) Issues Paper (2019 Issues Paper). We consider that cross-submissions are particularly useful for matters such as TPM reform where there are competing and disparate views.

We thank other submitters for their valuable and informative contribution to the TPM reform debate. Our review and consideration of matters raised by submitters has served to reinforce the concerns and misgivings we expressed in our submission. We confirm that, having read and reviewed the submissions, our views on the Authority's proposal are unchanged. As we submitted, we consider that the current TPM proposal "may not meet the Authority's statutory objective of delivering significant long-term benefits to consumers … [and] may not support New Zealand's transition to a low emission's economy."

We have previously outlined our strong support for the Authority to include a conference as part of the final stages of its review. In our view, following the first round of submissions, and given the opposition, diversity, and spread of perspectives on the TPM, we consider that an industry conference is essential. This need is reinforced by the recently announced strategic review of the Tiwai Point aluminium smelter by Rio Tinto. An industry conference could assist the Authority to decide whether to progress the review, which it could then do with confidence that it has heard and understood the competing perspectives of stakeholders.

The cost-benefit analysis (CBA) is fundamental to the Authority's TPM proposal. From our perspective, it would seem imprudent to advance further with the TPM proposal while the actual benefits of it are subject to such discordant expert opinion. At a minimum, we consider that holding an experts' industry conference is necessary to both identify and determine how best to resolve the issues that have become apparent with the CBA.

Our cross-submission comprises this letter, the attached Axiom-farrierswier (Axiom) review of submissions in relation to the quantitative CBA and an Appendix summarising the key themes we have observed in submissions. In our view these themes illustrate there are substantive issues to be worked through before final decisions can be made on whether to change or replace the TPM Guidelines.

## There are significant problems with the quantified CBA

We asked Axiom and farrierswier to consider whether submissions caused them to revise the conclusions in relation to the CBA as set out in the independent expert report attached to our submission. Their consideration of that question is provided by the attached letter.

It is clear the CBA continues to be a difficult and vexed element of the TPM review. The Axiom finding that there are significant problems with the CBA is, in particular, consistent with HoustonKemp's findings. The Lantau Group and NZIER expert reports also found material problems with the CBA. Axiom observes that "The only party to provide an endorsement *of a kind* to some aspects of the CBA was NERA in its report for Meridian" but "that support was qualified and limited in its scope" and "also lacked a robust foundation".

Axiom's review of submissions confirms and reinforces their own findings "that the new CBA could not reasonably be relied upon to support the Authority's proposal" and "those submissions and reports that touched upon at least some aspect of the CBA modelling serve primarily to bolster our core findings". Axiom's conclusion is that the scope of the analysis NERA were instructed to perform left them without "a sound basis to offer an informed opinion as to the efficacy of the top-down modelling methodologies or the resulting benefit estimates. We consequently did not find anything in its report that cast any doubt over the conclusions that we – and others – reached in relation to these additional elements of the CBA."

## Electricity Price Review and Government electricity reforms

Many of the submissions urged the Electricity Authority to take a 'wait and see' approach to the Electricity Price Review (EPR) Panel's recommendations before deciding where to go with the TPM review. However, while various stakeholders wanted the EPR to help the Authority resolve the TPM review and deliver final decisions, the Government has yet to decide whether to issue a Government Policy Statement on transmission pricing. The Government has indicated it will make that decision after reviewing the submissions made in response to the current TPM consultation.

One of the EPR Panel's suggestions for TPM reform is that the costs of future grid investments should be recovered on a beneficiaries-pays basis, moving away from the pure postage stamp approach. We want to be clear that we do not conflate the principle of "beneficiaries-pays" with the Authority's proposed benefit-based (BB) charges method. The BB charges method relies on forecasts of beneficiaries and their private benefits, made ahead of the investment actually being made, to set charges that are then fixed for many decades. As we submitted "Inevitably, any forecast of benefits that will arise over several decades will be wrong … [and] in our considered view, the probability of the benefits estimates proving to be right, or materially right over the 30 to 50-year life of an interconnected grid investment is low." We believe the Authority's TPM proposal would delay and constrain Transpower's ability to respond effectively and efficiently to market and industry initiatives, including those that may advance electrification and improve New Zealand's climate change position. Consequently, we remain of the view that "It is hard to see how such a regime could be durable."

While we consider it is possible to make simple changes to the current TPM to better recover the costs of grid investments to reasonably achieve a beneficiaries-pays basis, we confirm that we consider the Authority's proposed BB charges method has a non-trivial risk of undermining New Zealand's climate change objectives and being detrimental to the long-term benefits of consumers.

We consider the Authority's TPM proposal is unlikely to be durable, including because it can reasonably be expected to:

- consciously and deliberately encourage additional consumption during peak periods putting upward pressure on wholesale prices and causing more investment in gas-fired peaking generation, transmission and distribution – since these are natural consequences of higher peak demand;
- provide commercial incentives for parties to withhold information from grid investment processes (ours and the Commerce Commission's);
- result in major investment decisions being bogged down in private interests and disputes at the expense of security, reliability and wider economic and social wellbeing considerations (including responding to climate change);
- delay timely, efficient grid and low-emissions generation investment leading to higher electricity prices and greenhouse gas emissions;
- have a net result of higher overall electricity prices and elevated greenhouse gas emissions – a double blow for the New Zealand economy; and
- exacerbate the energy affordability problems afflicting too many consumers.

Another EPR Panel view is that the costs of historic grid investments should not be reallocated unless the reallocation would result in substantial long-term benefits to consumers. The CBA does not specifically test the impact of excluding or including the reallocation of historic investments and so risks not meeting that threshold. It may be useful for the Authority to undertake a quantitative analysis of individual investments to test the outcomes of status quo, recovery through the residual charge and the proposed Schedule 1 allocations.

The EPR Panel also suggested there should be a phase-in period, where necessary, to avoid price shocks. There is broad agreement amongst submitters that some form of phase-in or transition mechanism is needed, but further work on the design of it is required. As we and others submitted, the Authority's proposed price cap will not prevent price shocks.

The Government's response to the EPR has set an expectation that the Commerce Commission and Electricity Authority will raise the level of consumer and small participant engagement in their respective processes. The new Consumer Advocacy Panel recommended by the EPR Panel can be expected to engage in the investment decision processes (ours and the Commerce Commission's) regardless of the prevailing TPM. We look forward to this new voice providing its valuable perspective as we engage with our stakeholders to inform our investment decisions.

## TPM development process requires time for engagement

It is clear the majority of submitters expect and recognise the importance of a proper development process including full consultation with our customers and other stakeholders through each stage of the TPM development process. We summarise these stakeholder views in Appendix 1. We can understand and sympathise with Meridian and NZAS' desire for a quick resolution of the TPM review, including the development and implementation stages. The proposal that TPM development be undertaken within 12 months, however, is not reasonably practicable.

Meridian's suggestion that the TPM development process be shortened by excluding stakeholder engagement and consultation could cause a number of problems. Stakeholder engagement would be a critical input into our thinking and TPM development. Absent stakeholder engagement, we would need to do more work in-house (and with external support) and the result could be no real time saving with a far lower likelihood that the resulting TPM proposal would be to the long-term benefit of consumers or able to be approved. Not engaging with stakeholders also risks exposing TPM development to formal legal challenge on procedural grounds.

For our 2014/15 TPM Operational Review, the two consultation rounds plus workshops were critical steps that assisted us to develop our proposed TPM amendments, and to have confidence that the proposals had broad buy-in and support. There is no shortage of examples of projects that were derailed or ended up taking substantially longer than they should have because there was inadequate or no consultation through the development stages.

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

Yours sincerely

Alison Andrew
Chief Executive

## Appendix 1: Common themes from submissions

There has been constructive engagement from stakeholders on the latest TPM proposals, including issues around the specification of the TPM guidelines (Guidelines) and the implementation process.

While industry consensus cannot necessarily be expected, we conclude there is wide support for moderate reform and retention of some form of permanent peak usage charges. These points can be seen in the large number of submissions that have proposed or advocated pragmatic and readily implementable options directly targeted at the issues the Authority has identified. This advocacy includes the option to reform peak usage charges to ensure they are well targeted and do not over-signal.

Compared to the last round of TPM consultation three years ago, we have observed an increased focus on the implications of new technology and the transition to a low carbon economy. There is clear recognition the TPM needs to support investments that help the country achieve its climate change ambitions through electrification and renewable generation. This highlights the importance of the grid investment and BB charging determinations operating in a consistent and co-ordinated manner. At one extreme, disputes over cost allocation could spill over into the question of whether investments should be approved.[1] We felt the concerns raised by Tilt Renewables and Tauhara North No 2 Trust about implications for renewable generation and smaller operators were particularly informative.

While elements of transmission pricing are contentious, there are some strong and clear themes that have emerged from the submissions. The examples below illustrate that there are a number of substantive issues to be worked through before final decisions are made on whether to change or replace the Guidelines:

| Submission theme | Illustrative quote |
|---|---|
| • Wide support for consideration of more incremental and moderate reform options | Mercury: "… we do not accept the problems identified justify wholesale reform of the TPM or that smaller scale alternatives within the existing TPM have been exhausted". |

[1] Our customers will have reasonable incentives to try and minimise their share of any BB charges, just as they have incentives to keep all their costs down. The two determination processes could potentially spill over into each other if, for example, our customers attempt to downplay the benefits they would receive or consider we have overstated their share of the benefits of a new investment.

| Submission theme | Illustrative quote |
|---|---|
| • The Authority's proposal would not ensure consumers only pay for assets they benefit from | Electric Kiwi: "Any benefit- determination, whether calculated by Transpower or the Electricity Authority will invariably be wrong. … The Electricity Authority's view …that South Island consumers are net beneficiaries of the HVDC link highlights how unsafe a benefit-based approach to network charging is. South Island consumers would be better off if Transpower 'cut the cable' … The only reliable way of ensuring consumers don't pay more for transmission, or any other services, than they benefit is to ensure there are clear pricing signals consumers (and/or their service providers) can respond to. If there are clear pricing signals which reflect the cost (including future cost) of transmission, consumers will only consume where the benefit outweighs the cost. This does not require the Electricity Authority or Transpower to [determine] what they think individual consumer-benefits are." |
| • Application of BB charging is highly sensitive to assumptions and methodological approach adopted | PwC Distribution Group: "We also note how difficult it appears to be to apply a benefit based charge in practice. Analysis of the indicative calculations accompanying the 2019 issues paper reveal how sensitive the outcomes are to certain assumptions and judgements" and "there are significant challenges in quantifying and assigning the expected future benefits of prospective investments". |
| • It is not practicable to model and monetise some benefits of grid investment | Meridian: "For example, in the resource management context, courts have said that "it is simply not possible to express some benefits or costs in dollar or economic terms" but that this does not "disparage, as a lesser means of decision making" the need to evaluate all the merits of the proposal against the relevant criteria. Indeed, in the merger authorisation context the courts have said that qualitative factors "can be given independent and, where appropriate, decisive weight".<br><br>Tilt Renewables: "There is fundamental difficulty in assessing and allocating the benefits of new transmission in a highly meshed system. In some ways it is like trying to assess the benefits of individual members in a structural system. All occupants benefit if the structure is weathertight and sound, just like all transmission consumers benefit from a robust transmission system that enables competition between generators" |

| Submission theme | Illustrative quote |
|---|---|
| • Pragmatic approaches to determining benefits should be considered | Unison and Centralines: "… consideration needs to be given to … whether the models give adequate recognition to the purposes of some of the investments, particularly where they have been made to improve reliability and resilience, which may not be captured in the vSPD modelling. It may be more preferable to adopt simpler models or zonal approaches than rely on complex models such as vSPD". |
| • The vSPD method used to reallocate the costs of historic investments has issues that need to be resolved | Rio Tinto: "The Authority has adopted an approach to the charging for pre-2019 assets that is inconsistent with its own principles that benefits-based charging should take account of net private benefits. For example, the approach will result in NZAS being allocated a material portion of HVDC charges despite the Authority's own modelling estimating a net benefit of minus $47m over the 4 year period of its study. Rio Tinto is not satisfied that the Authority has provided a coherent rationale for its decision." And, "In the absence of a robust explanation, … [the Authority's vSPD method] risk[s] the impression the Authority was solving for a predetermined, and undisclosed, outcome. In addition, the modelling that determines these charges does not reflect the realities of the New Zealand transmission grid and hence the benefits it provides."<br><br>Rio Tinto: "... the Authority appears to only model competition benefits in the way it has assessed beneficiaries for existing assets. This narrowing of the concept of benefit by the Authority is a concerning precedent set by its modelling. One of the purposes of including historical investments in a benefits-based charge is so that, in the future, parties advocating for investments would know that, if they are beneficiaries of the investment, they will pay. However, the Authority's approach would set a precedent where future beneficiaries of reliability focused investments could advocate for an investment and argue that they should only be allocated costs on the basis of how much they benefit from competition."<br><br>ENA: "some transmission assets (NAaN is an example) that had positive benefits under TPM2 in 2016, are assessed as having nil benefits under TPM3 (but may have positive benefits at some stage in the future). This suggests to us that if NAaN was decommissioned consumers would be no worse off, which is of course nonsense simply because NAaN provides reliability benefits to the upper North Island which are not accounted for in the TPM3 proposal. The big weakness with the vSPD methodology that underpins the benefits-based component in the proposal is that it misses these |

| Submission theme | Illustrative quote |
|---|---|
| | benefits. This problem with the vSPD approach will also impact all seven of the assets that are subject of the benefits-based methodology and, if Transpower is required to use the same approach for future investments, to those future assets as well."<br><br>Unison and Centralines: "… consideration needs to be given to the whether the models give adequate recognition to the purposes of some of the investments, particularly where they have been made to improve reliability and resilience, which may not be captured in the vSPD modelling. It may be more preferable to adopt simpler models or zonal approaches than rely on complex models such as vSPD".<br><br>Entrust: "It does not appear the Authority has dealt with the substantive concerns about its proposed vectorised Scheduling, Pricing and Dispatch (vSPD) method for determining who benefits from historic investments. Vector, for example, detailed some of the ways "the proposed SPD method overstates consumer surpluses and understate producer surpluses".3 At the Auckland TPM Workshop the Authority revealed its vSPD methodology could not identify any benefits from the North Auckland and Northland (NAaN) upgrade which brings into question the efficacy of the method. |
| • Removal of peak-usage charges would result in higher wholesale electricity prices (not lower prices) | Vocus: "If Transpower were to remove its peak-usage pricing signal peak-demand would increase, as the Authority has indicated. This would result in an increase in investment in firm peaking generation to meet demand and would drive up spot prices, not reduce them. It would also require increased distribution network capacity which needs to be taken into account in the CBA. If the Authority is wrong on this point then the positive net benefit it has derived from its CBA would be negative." |
| • The Authority's proposal may not support New Zealand's climate change response | Tilt Renewables: "The continued entry of new wind and geothermal projects is key to NZ meeting its decarbonisation targets; however, Tilt Renewables has serious concerns that the Transmission Pricing Methodology ("TPM") as proposed by the EA would make it significantly more difficult to bring a project like Waipipi to market due to uncertainty related to transmission charges". |

| Submission theme | Illustrative quote |
|---|---|
| • Application of the Authority's BB charging proposal would be contentious | ENA: "If it goes ahead, the impact of the benefits-based charge in the TPM3 proposal will not be clear until Transpower develops the methodology but it will for certain remain contentious because of its arbitrary nature. In the end it will however depend on the final scope of the benefits-based charge mechanism (that is, whether it includes all 7 assets as proposed, or just HVDC or some other choice of assets to include). … Our last point here relates to Transpower's ability to accurately estimate the 30 to 50-year private benefits from transmission assets, especially when facing the type of changes that are contemplated for the electricity industry. We consider the approach will most certainly result in more dispute and non-trivial cost to the economy." |
| • The risk of unintended consequences needs to be taken into account | Electric Kiwi: "Despite the multiple warnings to the Price Review that it needs to consider the "risk of unintended consequences", the Electricity Authority has failed to heed to its own warning in the TPM review. … This is despite widespread concerns raised by Transpower and others about the risks major changes to the TPM could have for the wholesale electricity market, future electricity industry investment requirements, the impact on carbon emissions and electrification etc. … Electric Kiwi cannot think of any Electricity Authority proposal or project that has greater risk of unintended consequences than the TPM proposals." |
| • The proposed re-opener provisions will lead, over time (and potentially immediately in the case of the historic investments), to material mismatch between the benefits our customers receive from the grid and the BB charges they are required to pay. [2] | Meridian: "The provisions about adjustments to the benefit-based and residual charges could be drafted to expressly cover a greater number of situations that may arise. Alternatively, adjustments and reopeners may be appropriately left to Transpower to develop and describe in detail in the TPM".<br><br>Vector: "Another concern with beneficiary pays that has been raised by Professor Bunn and others is the treatment of dynamic effects. For example, would charges be recalculated if the forecasted long-term benefits do not materialise? What happens if extra capacity is built in a region to accommodate demand from a large industrial customer who then exits? The Authority has acknowledged that they do not have a solution to such dynamic effects and have not attempted to |

[2] Contact and Powerco recommended the recalculation and reallocation occur at each Individual Price-Quality Path (**IPP**) reset. This would only have merit if the IPP determination and BB charge determinations were staggered and did not overlap (e.g. the BB charge determination process could occur immediately after the Commission had made its IPP determination).

| Submission theme | Illustrative quote |
|---|---|
| | address them. According to Professor Bunn, “this is unsatisfactory… dynamic fairness needs further consideration by the EA”. |
| • Reassignment/optimisation provisions need to be clear, simple and avoid arbitrary triggers | Powerco: The beneficiaries of transmission assets will change through time – if a benefit-based charge is to be used, its design must account for this, and the simpler the better because changes in benefit shares will happen again. The reassignment provisions implicitly acknowledge this – an alternative is to recalculate benefit shares a periodic exercise rather than by a trigger mechanism.<br><br>Meridian: “Leaving it to Transpower to develop the various adjustment mechanisms that are proposed will allow for further consideration to ensure that the mechanisms work as well as possible. Taking the reassignment provisions as an example, clauses 33 to 38 are not particularly clear on important aspects of this mechanism, as presently drafted. Neither those clauses nor the definition of “reassignment” defines what will trigger the reassignment process in the first place. The definition of “reassignment” refers to “a reduction in the value of an asset” but this is imprecise. Moreover, aspects of reassignment may have arbitrary outcomes. For instance, clause 32(b)(i) captures the situation where a single party’s disconnection causes the value to be less than 80 per cent, but the provisions on reassignment do not provide for a situation where multiple parties’ disconnection would cause the value to be less than 80 per cent or more. Finally, the Guidelines do not make it clear whether reassignment can occur in conjunction with other adjustment mechanisms contained in the TPM. All of this indicates that the Guidelines on adjustment mechanisms should be general in nature and should leave it to Transpower to flesh out the precise scope of each mechanism”. |
| • Getting any new TPM right means allowing Transpower time and full stakeholder engagement | ENA: “The ENA also consider that Transpower is not being given a lot of time within which it needs to develop and implement TPM3. Unchanged, the proposal further increases the risk that Transpower will get parts of TPM3 “wrong” - which means early aggravation and increasing commercial and regulatory risk for both them and their customers”.<br><br>IEGA: “the process outlined in section 6 of the consultation paper is, in our view, inconsistent with good regulatory practice. The IEGA submit that Transpower must be allowed sufficient time for thorough analysis and formal consultation while developing the methodology based on the |

| Submission theme | Illustrative quote |
|---|---|
| | Authority's Guidelines. … If Transpower completes thorough consultation and engagement with industry stakeholders while considering options and finalising a methodology it puts to the Authority in the final step, when the Authority consults on Transpower's proposal the proposal should be well anticipated and transparent".<br><br>Buller Electricity: "Given the length of time the Authority has taken to progress TPM reform to its current status, the proposed timeline for Transpower to develop and implement the TPM is ambitious. This is especially the case as the guidelines now provide Transpower with more flexibility and consequently more development and decision-making responsibility on key issues. This will add to Transpower's burden in terms of the development, consultation and implementation workload which will be required, and take more time".<br><br>Various other submitters, including ENA, Entrust, King Country Energy and Powerco expressed similar concerns. |

18 October 2019

Ms Alison Andrew
Chief Executive
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Dear Ms Andrew

You have asked us to consider whether any of the materials lodged in response to the Electricity Authority's (Authority's) third transmission pricing methodology (TPM) issues paper (the Issues Paper) cause us to revise the conclusions we set out in our report in relation to the quantitative cost-benefit analysis (CBA). In short, they do not. They instead serve to reinforce our findings.

## 1. Recap of our key findings

In our report we concluded that the new CBA could not reasonably be relied upon to support the Authority's proposal. First, we noted that the underlying foundations of the CBA were unsound. For example, the ways in which the 'status quo' and alternatives had been defined were inappropriate because:

- there are many ways in which the existing TPM could be refined within the existing guidelines (e.g., the strength of the existing regional coincident peak demand (RCPD) price signal could be changed), yet the modelling ignored this and took the existing TPM as the 'baseline' for comparison; and
- the alternatives examined in the CBA included only the proposed approach and one other option, e.g., a long-run marginal cost (LRMC) based method was not included, despite the recommendation contained in the Authority's 'nodal pricing and LRMC paper'[1] and its status as a generally accepted infrastructure pricing methodology.

Key aspects of the modelling also did not depict the methodology that had been proposed:

- the grid use modelling (which produced 96% of the estimated net benefit) did not include the implicit forward-looking 'shadow' price signals that the Authority claimed would be supplied by the proposed benefit-based (BB) charges;
- the 'top-down modelling' included the wrong forward-looking price signals, i.e., the model mistakenly assumed that consumers would face price signals that reflected a rudimentary measure of the LRMC of transmission; and
- the results of the grid use model could also be reproduced using almost any methodology comprised solely of fixed charges, i.e., those allocations did not need to be based on estimated benefits – any number of alternatives could be used.

1 This paper recommended that LRMC pricing options be tested further – including through a CBA. *See:* Electricity Authority, *Nodal pricing and LRMC charging*, p.2.

Second, we pointed to some obvious and, in many cases, very serious errors in the modelling; including that:

- the grid use model relied on assumptions that did not reflect reality, including that investors would not consider future returns when deciding whether to invest in grid-connected generation, which resulted in the CBA predicting an influx of new generation investment that would be unprofitable in many instances;
- the grid use model included ~$2.3b in wealth transfers that were neither benefits to New Zealand's economy nor improvements to the overall efficiency of the electricity industry – these were payments from one group of consumers (generators) to another (final consumers), i.e., it was not 'new wealth';
- the grid use model ignored the cost of additional investment in generation ($1.9b) and distribution networks (conservatively ~$27–$81m) that would be needed to support the noticeable increase in peak demand that the Authority had forecast to occur if its proposal was adopted – it also understated the costs of the additional transmission investment that would be required (by ~$180m);
- the CBA ignored the cost of additional carbon that would be likely to be produced if peak demand increased in the manner forecast (since gas fired peaking plants were forecast to be used to meet that incremental demand);
- the top-down model of 'improved scrutiny of investments' overlooked the fact that the 4.4% 'efficiency factor' driving the results was irrelevant and overstated;
- the top-down model of 'increased certainty for investors' was driven by two assumptions with no objective foundation – one of which served to randomise the results; and
- the models included calculation errors and statistically insignificant inputs that further undermined the efficacy of the analysis and conclusions.

Third, we highlighted that the results of the modelling raised questions about the timing of the proposed reform. We observed that even if the CBA modelling was taken at face value – without addressing any of the substantial issues described above – then:

- the proposal would not be expected to deliver a significant net benefit in net present value (NPV) terms for around *twelve* years (until ~2034); yet
- the Authority expected that there would be a significant 'uncertainty event' – such as a major TPM review – after *eleven* years.[2]

Overall, we concluded that it was not possible to conclude that the proposal would deliver a net benefit to New Zealand's economy or improve the efficiency of the electricity sector. We noted also that if just two of the more serious problems described above were addressed (the inclusion of ~$2.3b in wealth transfers and the exclusion of ~$2b of additional costs) the estimated net benefit would drop by more than $4b and become a substantial net cost.[3]

2 This was one of the assumptions in the Authority's top-down model of 'improved investor certainty'.

3 We did not suggest that that this represented a sound estimate of the likely net benefit – or cost in this case – from implementing the proposal. It was simply the revised result obtained when the two issues were addressed. Even with those corrections, the CBA would remain unfit for its intended purpose on account of the other shortcomings we identified in our report.

## 2. Criticisms of the CBA

By our reckoning, at least twenty-five other submissions or reports touched upon some aspect of the CBA modelling.[4] Only two reports appear to have examined the minutia of the CBA through an extensive interrogation of its inputs, outputs and underlying assumptions: our own and HoustonKemp's (prepared on behalf of Trustpower). HoustonKemp's analysis and findings were consistent with our own. It highlighted all the same problems[5] and reached equivalent conclusions:[6]

> *'The EA's cost benefit analysis:*
>
> - *contains errors in its conceptual framework that cause it to overestimate benefits and underestimate costs and which, when corrected, show the proposal to give rise to net costs;*
> - *contains further errors of assumption and approach that render its results unreliable and not fit for its intended purpose;*
> - *does not reflect a best practice approach because it does not consider alternative options and incorrectly specifies potential outcomes under the status quo;*
> - *assumes the efficacy of its proposal but does not show this to be the case; and*
> - *does not support reform to the TPM guidelines in the near term since, even on its own estimates, the EA does not establish substantial net benefits arising from its proposal over the next decade.*
>
> *'In our view, **these errors are just as serious, and in some respects more acute, than the errors in the 2016 cost benefit analysis** that caused the EA to delay the development of the TPM guidelines. In its current form, **the EA's cost benefit and options analysis does not provide a basis upon which to form a conclusion that its proposal gives rise to net benefits**, either in its own right or as compared to alternatives.'* [emphasis added]

HoustonKemp used different approaches to measure the extent of the wealth transfers included in the benefits estimate and the additional distribution and transmission costs. It consequently found that the net benefit had been overstated by around $5b,[7] whereas our estimate was closer to $4b.[8] However, these methodological differences are easily reconciled and do not detract from the crucial point of commonality – namely, that addressing these errors would flip the claimed $2.7b net benefit to a substantial net cost.

The reports by NZIER (on behalf of MEUG) and the Lantau Group (on behalf of the TPM group) also contained substantive analyses of the CBA – or aspects of it (albeit with a

[4] These were: Trustpower, HoustonKemp on behalf of Trustpower, John Culy on behalf of Trustpower, MEUG, NZIER on behalf of MEUG, The TPM Group, The Lantau Group on behalf of the TPM Group, Meridian, NERA on behalf of Meridian, Vector, Professor Derek Bunn on behalf of Vector, Counties Power, Oji Fibre Solutions, Entrust, Electra, the Distribution Group, King Country Energy, Mercury, Northpower, Refining New Zealand, Vocus, Unison, Tauhara North No 2 Trust, Energy Trusts of New Zealand, Network Waitaki and the ENA.

[5] For example, it described (amongst other things) the flawed generator entry decision rule, the inclusion of wealth transfers, the exclusion of key costs and the problematic time-profile of costs and benefits.

[6] HoustonKemp, *Review of the cost benefit and options analysis of the EA's proposed TPM guidelines, A report for Trustpower*, 30 September 2019, pp.i-ii (hereafter: 'HoustonKemp report').

[7] *See for example:* HoustonKemp report, Table 4.1, p.42.

[8] For example, our ~$4b reduction was based simply on what would happen to the net benefit estimate if the two most obvious issues (the inclusion of wealth transfers and the exclusion of generation investment costs) were addressed, while HoustonKemp adjusted for these and several other matters. Naturally then, its recalibrated estimated net cost was higher than our own.

narrower scope[9] and/or higher-level focus than the assessments contained in our own report and HoustonKemp's). These assessments strengthen our conclusion that the modelling exhibits serious deficiencies and is ultimately unreliable. For example, NZIER drew attention to (amongst other things):

- the exclusion of additional distribution costs from the CBA;[10]
- the strong assumptions made in the grid use modelling about the extent to which mass-market customers would be exposed to time-of-use (ToU) pricing in the future and the absence of any sensitivity testing of different scenarios;[11] and
- the fact that the RCPD peak signal is probably much weaker than estimated in the modelling which, in turn, led to the benefits of more electricity use during peak periods being further overstated.[12]

The Lantau Group also echoed many of the concerns flagged in our report and HoustonKemp's. For example, it highlighted (amongst other things):

- the unduly narrow specification of the analysis (the 'CBA scenarios'), including the fact that the 'baseline scenario' included an RCPD peak signal that is widely recognised as being too strong (a 'clear economic flaw');[13]
- the failure to account for forecast additional generation investment costs[14] and the inadvertent inclusion of wealth transfers;[15] and
- the time-profile of costs and benefits, whereby net benefits would be low or negative in the early years with the alleged major net benefits arising a decade or more later.[16]

Numerous other parties also raised problems with the CBA. These criticisms focussed typically on particular deficiencies and tended not to go into as much detail as the reports described previously. Nevertheless, the points raised were invariably valid and reinforced the shortcomings in the modelling we identified. By and large, the observations on the modelling fell into one of the following broad categories:[17]

- The striking increase in the overall purported net benefit from the previous CBA, which was assessing a very similar proposal. For example, Mercury noted that:[18]

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9 For example, the NZIER report states explicitly that: 'In view of the complexity of the CBA the scope of this advice has been narrowed to a stocktake of the current aspects of the CBA to consider' (*see:* NZIER, *TPM 2019 Cost benefit analysis, Initial review, NZIER report to MEUG*, 1 October 2019, p.i – hereafter: 'NZIER report').

10 NZIER report, p.8.

11 NZIER noted that the modelling assumes that the proportion of mass market consumers exposed to ToU pricing would increase to 50% by 2032 and reach 100% by 2050. *See: Op cit.*, p.3.

12 *Op cit.*, pp.3-8.

13 The Lantau Group, *Review of Transmission Pricing Guidelines Issues Paper 2019,* 1 October 2019, pp.4 and 30 (hereafter: 'Lantau Group report').

14 *Op cit*., p.33.

15 *Ibid*.

16 *Op cit.*, p.5.

17 For the avoidance of doubt, this does not represent an exhaustive account of all the problems raised in the reports and submission. However, we think it gives a good sense of the principal recurrent themes. Note that internal footnotes have been excluded from all quotes for ease of presentation.

18 Mercury, *Consultation Paper – Transmission Pricing Review: 2019 Issues Paper*, 1 October 2019, p.8.

*'From an analytical perspective, Mercury is doubtful the overall net benefits from the proposal could be as high as $6.4 billion. Comparing this to the net benefit from the 2016 proposal of $0.2 billion, the high end 2019 proposal is 30 times the expected net benefit for what essentially [sic] the same proposal.'*

- The failure to model the Authority's proposal and the fact that the results of the grid use model could be replicated using nearly any methodology comprised solely of fixed charges. For example, Entrust observed that:[19]

  *'None of the three CBAs the Authority has used as part of the TPM* ***review are CBAs of the Authority's actual TPM plans*** *… … The CBA results aren't useful for determining whether the Authority's planned TPM changes should be adopted, as they don't require introduction of benefit-based charges or their application to any historic investments. The results would* ***essentially be the same if the Authority proposed a simple fixed-charge based TPM****, which retained South Island generators paying for HVDC.'* [emphasis added]

- The implausibility of the forecast generation investment and the resulting predicted reduction in wholesale prices. Oji Fibre Solutions was one of numerous submitters that challenged those facets of the modelling, observing that:[20]

  *'The fundamental issue with the CBA is that it assumes a fall in wholesale electricity pricing as a result of investment in new generation in response to increases in load. New generation will only be built if it increases the profitability of the owner of such new generation. Fundamentally this relies on sustained higher electricity prices to justify the investment. The logical conclusion is therefore that* ***consumers cannot benefit from lower electricity prices which will not eventuate****.'* [emphasis added]

- The decision to exclude the cost of the forecast additional generation investment. A number of submitters questioned that approach, including Tauhara North No 2 Trust, which stated that it was:[21]

  *'… puzzled by the exclusion of generation costs brought forward by the proposal on the basis that those investments are assumed to be efficient. The fact that the proposal makes new generation viable earlier* ***does not mean it is not a cost associated with the proposal****'* [emphasis added]

- The inclusion of wealth transfers in the net benefit estimate. Northpower was one of several parties that questioned the veracity of the purported benefit from more efficient grid use on that basis, noting that:[22]

  *'…* ***nearly all of that benefit is simply a wealth transfer from existing generators****. There might be a small increase in overall demand (i.e., a reduction in deadweight loss), but the majority of that 'benefit' would come simply from generators receiving lower prices for electricity that they would have sold anyway at the previous, higher price. Conservatively, we would expect this wealth transfer to account for at least 70% of the $2.6b benefit estimate.'* [emphasis added]

- The failure to consider additional distribution costs. Of all the submitters that highlighted this shortcoming Vector arguably provided the most succinct synopsis:[23]

  *'The modelling does not include any estimate of the costs of increased distribution investment resulting from higher peak demand.'*

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19 Entrust, *Electricity Authority TPM changes will 'fleece' Kiwi consumers and the regions*, 26 September 2019, pp.2-4.

20 Oji Fibre Solutions, *Re: 2019 Issues Paper: Transmission Pricing Review consultation paper,* 1 October 2019, p.4.

21 Tauhara North No 2 Trust submission, 1 October 2019, p.4.

22 Northpower, *2019 Issues Paper Transmission Pricing Review*, 1 October 2019, pp.9-10.

23 Vector, *Submission to Electricity Authority Transmission Pricing Methodology 2019 Issues Paper*, 1 October 2019, p.15.

- The lack of consideration of environmental and carbon emission concerns. For instance, Refining New Zealand observed that:[24]

  *'We do not believe that new peak generation [which the CBA predicts if the Authority's proposal is adopted] will improve the carbon footprint of the electricity grid. On the contrary, encouraging more demand during peak periods would only* ***detract from the Government's 100% renewable electricity and energy efficiency goals****…The CBA* ***ignores the cost of the additional carbon emissions*** *that could be produced if peak demand increases as forecast (for example, through constructing more generation or produced by the generation itself, e.g. geothermal)…While the EA acknowledges the importance of decarbonisation, it pays it no attention in its quantitative analysis.'* [emphasis added]

- The fact that most consumers are not currently exposed to the price signals to which they would be expected to respond. Orion was one of many submitters that questioned the Authority's projected future state of the world:[25]

  *'The paper acknowledges that, as of now, perhaps not many consumers face prices as posited, but that this will likely increase over time as distributors change to more cost reflective pricing, including TOU [time-of-use], and nodal energy prices change to reflect changes in demand. We challenge this, and we believe it reflects a fundamental flaw in the logic of the deadweight loss modelling.'*

- The time-profile of the costs and benefits, whereby most of the projected costs would arise in the first few years after implementation, but the purported benefits would not transpire until the mid-2030s. For instance, Professor Derek Bunn remarked that:[26]

  *'… through the projections the net benefits appear to depend most substantially upon what may happen between 2030 and 2050. Power markets change a lot and after a decade, in my experience from over 40 years work in the sector, market circumstances have always been very different from original expectations. That does not mean we should not plan for the future – we have to – but a CBA which relies mostly upon what happens after ten years is not appealing and may not be robust.* ***I am deeply concerned that a CBA for a pricing mechanism change, which will be implemented over a few years, is based upon scenarios to 2050…*** *A ten year horizon would be more appropriate. For comparison, the Ofgem Impact Assessment for the removal of triads considered a 12 year horizon. So,* ***to formulate a CBA of this price mechanism change as if were a long term physical infrastructure project is not just inappropriate but makes it look dubiously speculative and over-advocated****.'* [emphasis in original]

- Concerns about key input or modelling assumptions. For example, Network Waitaki challenged the Authority's modelling of battery investment, concluding that:[27]

  *'The presented strategy for use of utility sized battery banks* ***was not convincing****…The first concern appears to* ***indicate a lack of understanding*** *of certain issues… The* ***modeller seemed unaware*** *that the power required to charge the battery would be added to system demand, negating the assistance provided by the battery during the discharge part of the cycle.'* [emphasis added]

Accordingly, based on our review of the materials lodged in response to the Issues Paper, it would appear that:

24 Refining New Zealand, *Refining NZ submission on the Electricity Authority 2019 Issues paper – Transmission pricing review*, October 1, 2019, pp.2–3.

25 Orion, *Submission on Transmission Pricing Review – 2019 Issues Paper*, 1 October 2019, p.3.

26 Professor Derek Bunn, *A Commentary on the Electricity Authority 2019 Issues Paper on the Transmission Pricing Review,* September 25, 2019, p.9.

27 Network Waitaki, *Consultation paper – Transmission Pricing Review,* October 1, 2019, pp.31–32.

- no party endorsed fully the CBA methodology, assumptions or results[28], or presented any analysis contradicting – or questioning in any substantive way – our principal findings; and
- nearly all the commentary on the CBA was negative in tenor and highlighted a variety of problems with the approach that had been employed.

Perhaps most tellingly, the only two parties to have had an extensive 'look under the hood' of the CBA – HoustonKemp and ourselves – arrived at virtually identical views regarding the shortcomings implicit in the modelling and its overall robustness. In particular, we both determined that the CBA could not reasonably be relied upon to support the proposal.

## 3. Qualified support for some aspects of the CBA

The only party to provide an endorsement *of a kind* to some aspects of the CBA was NERA in its report for Meridian. We say: 'of a kind', because that support was qualified and limited in its scope. It also lacked a robust foundation. It does not appear as though NERA was asked to undertake a close examination of the modelling inputs and outputs or the underlying assumptions.[29] This can be inferred most readily from the brevity of its overview of the CBA. That discussion spanned only nine pages and was devoted primarily to simply restating what the Authority had done.[30]

This aspect of NERA's report was therefore primarily descriptive rather than investigative. For example, the commentary on the grid use modelling was almost *entirely* a reiteration of the Authority's approach. There was little analysis of the appropriateness of the methodology. Most notably – and perhaps understandably in the circumstances – NERA did not discover the numerous problems that would only have become apparent if it had been instructed to perform a more forensic review (see section 1).

Conversely, NERA *did* detect one of the serious shortcomings that could be seen most readily *without* inspecting the grid use modelling itself. Namely, it appeared not to be persuaded by the Authority's decision to include the $202m in avoided battery investment costs as a benefit in the CBA, but to exclude the $1.9b in additional generation investment costs. A degree of scepticism is perceptible in the following statement:[31]

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[28] NERA provided some support for certain aspects of the CBA in its report for Meridian. However, as we explain subsequently, that support was carefully qualified and lacked a robust foundation in any event.

[29] NERA touched briefly upon the issue of wealth transfers, but it missed the most obvious point – namely, the very large transfer from existing generators (such as Meridian) to final consumers. It also mistakenly implied that the modelling had been conservative (i.e., that it had understated the extent of the grid use benefit) by ignoring the change in producer surplus. NERA arrived at this view by examining a stylised supply and demand chart that appeared to depict an increase in producer surplus because of a 'tilting' of the supply curve. However, this stylised chart did not reflect accurately what was happening in the modelling. As our report explained, once the grid use model was examined it became clear that it was predicting that generators (i.e., producers) would earn significantly less revenue as a group under the proposal, while investing significantly more. There was therefore no increase in producer surplus. The reduction in wholesale revenue was driven almost entirely by wealth transfers from existing generators to final consumers.

[30] By way of contrast, the Authority's CBA modelling entailed over 500 spreadsheets, 10,000 lines of computer code, a 106-page Technical Paper and a further 37 pages in the Issues Paper itself.

[31] NERA, *Review of Electricity Authority's transmission pricing review 2019 papers, Meridian Energy,* 1 October 2019, p.16 (hereafter: 'NERA report').

*'In excluding this cost from the CBA, the Authority treats it differently from other costs such as the saving in battery costs and the increased cost relating to grid investments brought forward … We think it would be useful for the Authority to explain this distinction further.'*

In other words, NERA found one of the problems that could be spotted without a detailed investigation but missed all those that required a more comprehensive review to uncover (an assessment that it does not seem to have been requested to undertake). It is not possible to arrive at a robust conclusion based on a perfunctory 'surface-level' analysis. That is most likely why NERA did not explicitly endorse the grid use modelling *methodology* at any stage in its report. It instead provided a tentative – and qualified – endorsement of the *result* that the model produced.

Specifically, NERA compared the efficiency gain implied by the $2.6b purported benefit from more efficient grid use to three metrics. On the basis of that comparison it concluded that the *magnitude* of that particular category of benefit 'seems to be quite plausible'.[32] However, there are some crucial things to note here:

- there is an important difference between saying that the 'magnitude' of a benefit estimate is 'quite plausible' and concluding that the *methodology that was used to derive it* is robust (remembering that NERA did not endorse the grid use modelling itself), i.e., a benefit estimate can be 'quite plausible' but still wrong if it was produced using an unsound approach (as is the case here);[33]
- the three comparators it considered were irrelevant (e.g., the efficiency gain forecast from a proposed merger in the wool scouring sector is of no import in the current context) – even NERA acknowledged that they were 'not directly on point', indicating perhaps that it was irresolute in its conclusion;[34] and
- even setting these fundamental problems aside, suggesting that something is 'quite plausible' is, at most, a rather tepid endorsement, e.g., it is unclear whether NERA considered the purported number to be, say, 'quite *likely*'.

For those reasons, in our opinion, nothing in the NERA report called into question the conclusions that we – and others – reached in relation to the grid use modelling. NERA's discussion of the remaining elements of the CBA – most notably, the three 'top-down' models – was also extremely brief and contained little critical evaluation of the methodologies. On two occasions it acknowledged that it had not looked at certain models in detail. Specifically (emphasis added):

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32 NERA report, p.17.

33 Moreover, NERA performed no other analysis – including of the Authority's methodology itself – to examine whether the proposal would be likely to deliver net benefits or costs. That being the case, we do not consider that it was reasonable for it to suggest that the 'magnitude' of the purported net benefit was 'quite plausible' based simply on a comparison to other large numbers. Moreover, the same approach could have been employed to infer that a net *cost* of a similar magnitude was 'quite plausible' (i.e., by comparing the result to large *negative* numbers taken from other contexts). In other words, in our opinion, the contention had no analytical foundation and was, in any case, ambiguous.

34 NERA report, p.17.

- when discussing the approach for measuring the supposed benefits from 'improved investor certainty', NERA stated that: '***While we have not carefully worked through the Authority's modelling****, we think the broad framework is an appropriate one*';[35] and
- when describing the method employed to measure 'more efficient investment by generation and large load', NERA remarked that: "***At a high level****, the Authority's methodology looks appropriate*".[36]

These disclaimers speak to the superficiality of the analysis that NERA was ostensibly asked to complete. This is again also evident from its perfunctory nature and the clear errors that were missed that would have been revealed following a closer examination of the underlying models (see section 1[37]). In our view, the cursory scrutiny that NERA applied to these additional elements of the CBA was incapable of providing any meaningful insights into their robustness.

Accordingly, in our opinion, NERA did not have a sound basis to offer an informed opinion as to the efficacy of the top-down modelling methodologies or the resulting benefit estimates. We consequently did not find anything in its report that cast any doubt over the conclusions that we – and others – reached in relation to these additional elements of the CBA.[38]

In summary, our review of the materials lodged in response to the Issues Paper has not caused us to revise any of the conclusions that we set out in our report in relation to the CBA. Rather, those submissions and reports that touched upon at least some aspect of the CBA modelling serve to bolster our core findings.

Yours sincerely

Hayden Green
Director, Axiom Economics

Eli Grace-Webb
Director, farrierswier

[35] *Op cit.*, p.19.

[36] NERA report, p.18.

[37] For example, NERA did not recognise that the top-down modelling of 'more efficient investment by generators and large load' did not reflect the approach being proposed by the Authority and it missed the fact that the model of 'improved investor certainty' was driven by two arbitrary assumptions with no empirical foundation that randomised the outcomes. In both instances, these errors would have only become apparent once the underlying modelling itself had been reviewed.

[38] NERA was also asked by Meridian to calculate the impact of bringing the proposed TPM reform forward by one or two years (*See:* NERA report, p.20). However, its calculation was irrelevant for two reasons. First, it was based on the Authority's net benefit estimate which, for the reasons we have explained, is unreliable. Second, we understand that, from a practical perspective, it would not be feasible to introduce any new TPM prior to 2022. Such a timeframe would not allow Transpower enough time to design and implement the methodology or to provide its customers with sufficient notice of the resulting price changes.