

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 problems⁵ 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 scope⁹ 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 costs¹⁴ 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

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.'

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 results²⁸, 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

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):

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 1³⁷). 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.