10 June 2020

William Cairns
Chairman
Entrust
Auckland

By email

Dear Mr Cairns

Re: the TPM proposal and CBA

Thank you for your letter to James Stevenson-Wallace dated 20 May 2020. I have been asked to respond on the Authority's behalf.

As you will be aware, the Electricity Authority has now released its decision to issue new TPM guidelines and a process for developing a proposed TPM.

Prior to its decision, the Authority considered the issues raised in your letter – as it has considered matters raised by stakeholders throughout its TPM process – and remained satisfied with the process it has undertaken in respect of the TPM guidelines, including the robustness of its cost benefit analysis (CBA).

In relation to the particular concerns raised in your letter:

(a) The Authority has considered all submissions and expert reports provided to it throughout its TPM process. We have provided extensive responses to submissions in the information papers released earlier this year and the Decision Paper released on 10 June.

(b) As to submissions on peak charging, again all submissions and expert reports have been taken into account and, as set out in the peak charge information paper, such submissions have influenced the Authority's decision to include provision for a transitional congestion charge in its TPM guidelines.

(c) The Authority continues to be satisfied that its CBA modelling has been appropriate, for the reasons set out in its CBA information paper. This includes the treatment of wealth transfers.

(d) The Authority also remains satisfied with its modelling of demand, pricing and investment under a new TPM for the reasons outlined in the CBA information paper. For example, there is no inconsistency in the finding that removing the RCPD charge will result in lower prices and lower electricity demand in aggregate. Removal of the RCPD means that, relative to the baseline, prices inclusive of transmission charges fall and demand increases at peak. But in the modelling prices rise and demand falls at other times of use. Consumers benefit overall because they value energy consumption at peak times more than they do at other times.

(e) The Authority remains of the view that its formal consultation on the CBA has been appropriate and therefore determined not to conduct further formal consultation. In particular, and as noted in our response to the TPM Group, the changes to the Authority's CBA were made with regard and in response to submissions and cross-submissions, and the Authority considers that the resulting CBA is a robust estimate of quantifiable benefits.

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The median (and weighted mean) value of the estimate of benefits, while reduced, remains within the range of benefits consulted on in the 2019 Issues Paper. The Authority notes that, while it has looked to ensure that its CBA is as robust as possible, it is not the only matter to which it may have (and has had) regard to in reaching its decision.

(f) The Authority appreciates that the current circumstances around COVID-19 have generated significant uncertainties and it has looked to respond to these via other work streams. However, it does not consider that those circumstances detract from the need for a resolution of the TPM process, with the Authority considering reform in this area to be urgent and necessary.

We thank Entrust for its continued engagement with the TPM process.

Yours sincerely

Rob Bernau
General Manager Market Design

ELECTRICITY AUTHORITY
TE MANA HIKO

10 June 2020

Warren McNabb
Chair
Independent Electricity Generators Association

By email: warren.mcnabb@altimarloch.com
Copy to: contact@iega.org.nz

Dear Mr McNabb

RE: TPM Peak Charge papers released 12 March 2020

Thank you for your letter the Electricity Authority Board dated 28 May 2020. I have been asked to respond on the Authority's behalf.

As you will be aware, the Authority has now released its decision to issue new TPM guidelines and a process for developing a proposed TPM. Prior to this decision, the Authority Board considered the issues raised in your letter, as it has considered matters raised throughout the TPM process.

Having considered these issues, the Authority remained satisfied with the process it has undertaken, as well as the substantive position it has reached in respect of the TPM guidelines and on the transitional congestion charge in particular.

In relation to the specific concerns raised in your letter:

(a) The Authority is satisfied that it undertook sufficient engagement on the transitional congestion charge to proceed to a decision on the TPM guidelines. In addition to its submission and cross-submission processes in respect of the 2019 Issues Paper, the Authority heard oral submissions in December 2019 and released its information paper on the peak charge in March 2020. Following the publication of that information paper, the Authority has received a number of communications from stakeholders expressing further views on that paper, including IEGA's letter. These views have been considered. In light of the above, the Authority considers that stakeholders have received sufficient opportunity to engage with the various views on the congestion charge.

(b) The Authority disagrees that it has breached a promise made to come back to stakeholders on the peak charge. Even if such a promise had been made (which it was not, as is evident from the extracts quoted by IEGA), the Authority's release of the peak charge information paper would have more than fulfilled it. Further, the Authority noted in its information paper that it had spoken with Transpower, and Transpower concurred there would be merit in it leading a sector workshop on the design of the transitional congestion charge. This will provide a further opportunity for stakeholder engagement. The Authority expects this workshop to take place in the coming months.

(c) The Authority disagrees with the characterisation put forward in IEGA's letter that the information paper added very little new information or appeared to be a decision paper in all but name. Rather, as was noted at the time, the peak charge information paper looked to further explain and expand on the Authority's thinking, taking into account the various submissions received. It was not a decision paper, with the Authority's final decision on the TPM guidelines being taken on 4 June 2020. The Authority also disagrees that the paper acknowledged only a minimal number of submitters and points raised in submissions; rather, to avoid repetition, the paper addressed submissions thematically, citing examples of where particular points had been made rather than referring to all submissions individually – many of which made very similar points.

(d) The Authority has, throughout its process, sought to ensure that participants are thoroughly informed as to its proposals, commencing with the release of a detailed issues paper in July 2019 and accompanying workshops. The Authority has also provided clarification and further information through answering questions put to it and releasing information papers on key topics.

(e) The Authority disagrees with IEGA's characterisation that it is relying on timely and successful implementation of other work streams to ensure its approach is efficient. Rather, the Authority's approach allows the efficiencies associated with such advances to be taken advantage of, if or when they are put in place. In recognition of the fact that there is uncertainty and that risks could be more acute if relevant business processes or contracts, or some of the elements cited in IEGA's letter, were not yet in place as expected, the Authority has provided for the inclusion of a transitional congestion charge.

(f) The Authority considers the conclusions to be drawn from Concept Consulting's analysis of the Winter Capacity Margin do not alter as a result of Transpower's latest Annual Security Assessment. The Authority agrees that it is possible the margin could fall below the economic optimum if circumstances that describe Sensitivity 1 or 2 come to pass, though Concept stated its base case was most representative of expected outcomes. The Authority disagrees that the possibility of other outcomes therefore means a transitional congestion charge will have to have the features of, or be at a level similar to, the RCPD charge. Transpower has a number of management tools at its disposal (see pages i-ii of the information paper) and the optimal solution will depend on the particular circumstances.

(g) The Authority does not consider it necessary to conduct further analysis into the impact of low wind generation on spot prices in relation to the TPM guidelines. The guidelines relate to efficient transmission pricing, and its impact on demand (and in turn on grid and generation investment). The volatility in spot prices due to the changing availability of generation or different types of generation is not central to this. Efficient transmission pricing will contribute to the right investment in generation being made in the right place and at the right time.

(h) The Authority disagrees that its reliance on nodal prices and a transitional congestion charge would reduce diversity in peak management options – if anything, and for the reasons outlined in its peak charge information paper, the approach better highlights the different options available to participants including Transpower, facilitates the use of the most efficient solution and allows for further innovation.

(i) As to the alternatives IEGA proposes, the Authority's decision paper documents how the Authority has extensively considered the option of amending the current RCPD charge, as well as other alternatives, and concluded that such an approach would not yield as significant long-term benefits for consumers as would the Authority's approach now set out in the new guidelines.

We thank IEGA for its continued engagement with the TPM process.

Yours sincerely,

Rob Bernau
General Manager Market Design

10 June 2020

Peter Calderwood
General Manager Strategy and Growth
Trustpower
TAURANGA

By email: peter.calderwood@trustpower.co.nz

Dear Peter

Response to follow-up letters on the revised CBA of the proposed TPM guidelines

Thank you for Tom Kennerley's letter of 5 May 2020 to James Stevenson-Wallace with follow-up questions, and your letter of 19 May 2020 to Dr Brent Layton with consultants' comments, on the revised CBA of the proposed TPM guidelines.

The Authority wrote to you on 29 May 2020 to clarify the timeframe within which we intended to respond, to confirm the Authority had undertaken a detailed review of the revised modelling, and to confirm an updated CBA technical paper will be released (which has now occurred).

We now provide answers to the remaining questions. These are attached to this letter. We note that we have looked to provide answers by topic where we identified common themes and connections between questions. For your convenience, references to the original questions are provided in the footnotes.

We also note that:

a. some questions had already been answered, either directly during the webinar or in writing following the webinar, or in previous correspondence direct with you

b. some questions related to approaches already described in the 2019 CBA Technical Paper that were not subject to revisions

c. some points were observations rather than questions for us to answer.

In terms of the matters raised in your letters, as you will be aware, the Authority has now released its decision to issue new TPM guidelines and a process for developing a proposed TPM.

Prior to its decision, the Authority considered the issues raised in your letters – as it has considered matters raised by stakeholders throughout its TPM process – and remained satisfied with its process and with the robustness of its CBA.

In relation to the particular concerns raised in your letters:

- The Authority remains of the view that its formal consultation on the CBA has been appropriate. As noted in our response to the TPM Group, the changes to the Authority's CBA were made with regard and in response to submissions and cross-submissions from the industry and the Authority considers that the resulting CBA is a robust estimate of benefits. The median value of the estimate of benefits, while reduced, remains within the range of benefits consulted on in the 2019 Issues Paper and the Authority notes that, while it has looked to ensure that its CBA is as robust as possible, it is not the only matter to which it may have (and has had) regard in reaching its decision.

- The Authority continues to be satisfied that its CBA modelling has been appropriate, for the reasons set out in its information paper. This includes the treatment of wealth transfers, the exclusion of distribution costs (and benefits) and its estimates of benefits from increased scrutiny and certainty.
- In relation to estimates of the costs and benefits of additional grid investments, the Authority is satisfied that there are no inconsistencies, and that these estimates relate to increased demand at peak compared to the baseline. The implied benefit cost ratio is consistent with those indicated for example in the recent WUNI Major Capex proposal or Transpower's paper on the Clutha Upper Waitaki Lines Project.
- The Authority considers that the examples cited as portraying basic computational and very significant modelling errors do not show there are errors at all. In particular, one of the examples relates to deliberate and appropriate modelling adjustments, and another relates to the consultant using different time periods and data aggregations than used in the CBA.
- The Authority also does not accept the criticisms related to the data or the modelling of different demand scenarios, for reasons that were set out in its information paper, and as detailed in the attached response to Trustpower's follow-up questions. For example, the information paper specifically refers to how the Authority considered the data sources and scenarios that Trustpower says its consultant considers have not been incorporated properly.
- The Authority continues to be satisfied with its approach to modelling and the results. The Authority is familiar with the modelling tools Trustpower refers to, and notes that, while they have their strengths, these tools do not model consumer demand dynamics and the effects of changes to transmission prices on demand, which are of central interest in this context.

We thank Trustpower for its continued engagement with the TPM process.

Your sincerely

Rob Bernau
General Manager Market Design

Attachment: Responses to Trustpower's follow-up questions

Location of modelling data and results[1]

The Authority's modelled results relied on in the CBA information paper can be found on the EMI website under 'Supporting analysis for April 2020 TPM Information Paper'.[2] The relevant folder is called 'Grid use model/Sensitivities/Output'.

Results are summarised in the EMI folder 'Grid use model/Sensitivities/Summary'.

Framework questions[3]

Please refer to the information paper and the 28 April 2020 webinar presentation for why we:

a. use the change in consumer surplus in assessing the proposal's net benefits

b. consider lower wholesale electricity prices from new generation investment are the result of efficiency gains and therefore are benefits that need to be counted in the CBA

c. estimate benefits from less inefficient investment in utility-scale batteries

d. exclude distribution network costs and benefits.

In the analysis of generation investment and prices, producer surplus is measured as generator revenue (market price multiplied by dispatched quantities) less short-run operating costs (short-run marginal costs multiplied by dispatched quantities).

These calculations can be found on the EMI website (see footnote 2) in the file 'Grid use model/Sensitivities/Earnings.py'.

Battery investment[4]

As shown with an example at para A6 of the 2020 CBA Information paper, energy loss during battery operation is 10% (not 82% indicated in your question).

The simulation model used provides estimates of the net effects of utility-scale battery operation on grid-level demand, by time of use. This is done by noting the grid use model's four times of use prior to the simulation of battery operation and then calculating changes in demand by time of use. This calculation indicates that, in the presence of RCPD charges, one MW of batteries causes, on average:

a. 100 MWh reduction in peak grid demand

b. 100 MWh increase in peak non-grid demand

c. 22 MWh reduction in shoulder demand

d. 222 MWh increase in off-peak demand.

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1 Refer to: p.3 – question 2

2 Relevant programming code, input and output files can be found at: https://www.emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis/2020/20200417_TPM_CBAfilesToSupportApr2020InformationPaper

3 Refer to: p.3 – questions 3-4
pp.4-5 – question 10
p.8 – references 5iii, 6-6iii, 7

4 Refer to: p.6 – reference 2i.a

These numbers reflect changes in traded volumes of energy and amount to a net change of 199 MWh in the amount of energy traded. The change in final consumption demand is zero. There is a net increase in grid supply/demand of 99 MWh, reflecting energy lost during battery charging and discharging.

Generation investment, energy price formation, and associated data sources[5]

As discussed in the 2020 CBA information paper, we have revised the 2019 CBA's treatment of generation investment and energy price formation. This includes the introduction of offer curves and more stringent investment criteria, whereby investors do not invest unless they recover their estimated long-run marginal costs in the first year of operation. One consequence of these changes is that energy prices are higher, on average, than the long-run marginal cost of generation.

In the CBA the long-run marginal cost of generation is measured as the present value of capital and operating expenditure as a proportion of the present value of typical output. Following the assumptions in the 2016 EDGS, present value sums are based on an 8% post-tax real discount rate.

The 2019 CBA technical paper (paragraphs 2.194 – 2.195) noted that the data, scope of coverage and parameter values about generation plant are from the Generation Expansion Model input database used in MBIE's 2016 EDGS. Calculations of existing producers' short-run costs are based on 2016 EDGS assumptions of short-run marginal costs, excluding annual operating costs, refurbishment, or depreciation.

Since the 2019 Issues Paper CBA was prepared, MBIE has released a revised EDGS (in July 2019) and new generation investment has been announced and construction, or pre-construction, started.[6]

The revised 2019 EDGS refreshed some of the 2016 EDGS assumptions and scenarios around electricity demand growth and technology change. However, it did not revisit the detailed analyses underpinning the 2016 EDGS, such as capital costs of potential electricity generation investment projects.

Given this, we have continued to rely on the 2016 EDGS and used sensitivity analyses to assess a range of potential changes in generation costs and underlying drivers of electricity demand growth.

We have also relied on these sensitivity analyses in place of updating the 2019 modelling to reflect actual and potential changes in the electricity industry and New Zealand economy. We have chosen this approach because of the material increase in uncertainty over demand for, and investment in, electricity since the 2019 CBA was prepared. The use of sensitivity analyses helps us to accommodate this uncertainty in the updated CBA.[7]

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5 Refer to: pp.3-4 – questions 5-7
p.6 – reference 2ii
p.7 – references 5i-5ii
p.8 – reference 7i
p.9 – references 2, 2i, 2iv-2v
p.10 – references 3ii, 5

6 The approach to such changes was explained in the CBA information paper, page 8.

7 Refer to P 10 – reference 6. Given our approach to modelling and data sources, we do not consider there to be any inconsistencies.

The Authority answered the question why both total electricity consumption and average wholesale prices are estimated to reduce compared to the baseline following the webinar.[8]

To confirm, the modelling finds that total consumption, in MWh, would be lower under the proposal than under the baseline. Demand at peak increases because of the reduction in peak prices inclusive of interconnection charges. But energy consumption outside peak periods is, on average, 0.7% lower under the proposal compared to the baseline.

There are two main drivers of this effect:

a. interconnection charges are modelled as a per MWh charge under the proposal. This is the same approach used in the modelling for the 2019 CBA (see paragraph 2.10 of the 2019 CBA Technical Paper). This causes an increase in the cost of consuming electricity outside peak periods. This modelling approach will tend to overstate the demand reduction under the proposal (and thereby understate the proposal's benefit), to the extent that consumers respond to marginal electricity costs and not average costs

b. a small share (5-10%) of the lower demand under the proposal arises because the baseline includes more energy demand related to meeting energy lost during the charging and discharging of utility-scale batteries.

The welfare costs from net overall cost changes or reductions in electricity consumption are included in our calculations of welfare changes. See Equation 10 (paragraph 2.134) in the 2019 CBA technical paper.

The following points are important to note:

a. the CBA is not modelling the effect of a small change in demand on wholesale market supply, new generation investment and wholesale market pricing. Changes in demand are an output of the model, not an input. That is, the CBA is not measuring the efficiency of the generation and transmission investment paths under the proposal and the baseline. Rather, the CBA is measuring the efficiency of the current transmission pricing arrangements relative to the proposal and other options. The proposal results in a small change in demand and a different investment path for generation and transmission compared to the baseline

b. as the CBA modelling considers demand and supply jointly, it would be inappropriate to exclude the effect of changes in wholesale prices and costs without reconsidering other components of the CBA's modelled results, such as the effect of changes in the amount and timing of electricity demand

c. it is important to not make inferences about the connection between aggregate changes in prices[9] and aggregate changes in demand without considering the relative size of price changes by time of use, location, and consumer type. Consumers consider changes in both price levels and relative prices, across times of use, when choosing demand levels. vary by year, time of use, location, and consumer type.

[8] https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/tpm-2019-issues-papers-questions-and-answers-2/

[9] It is the total of changes in energy costs, transport costs and transmission charges that is relevant to consumers.

Nodal price differences, loss and constraint excess, and transmission investment[10]

The LCE, or transport cost, is modelled as a function of:

a. historical wholesale energy price differentials, and

b. growth in GXP-level demand, which is assumed to increase wholesale energy price differentials.

This is discussed at paragraphs 2.197-2.198 of the 2019 CBA technical paper. The transport cost calculations can be found on the EMI website (see footnote 2) in the folder 'Grid use model/Models", in lines 978-1000 of the model file 'Central.py'. This methodology is unchanged from the 2019 CBA.

The rate of change in the LCE, given a change in demand, is based on empirical estimates discussed in paragraphs 2.202 to 2.208 of the 2019 CBA technical paper. The data used in this empirical analysis is for the period 1 September 2007 to 31 August 2017. The data reflects nodal price differentials measured according to the 14 backbone nodes used in the CBA's grid use model. This data includes estimates of the capacity utilisation of the HVDC link, accounting for changes in the HVDC link's capacity over time. The typical percentage effect of demand growth on transport costs (other things being equal) can be read from the demand 'coefficients' in Tables 16 and 17 of the 2019 CBA technical paper.

The CBA's grid use model uses the estimated relationship between demand and transport costs to model changes in transport costs over time. Demand is the only factor used to model structural changes in transport costs. Thus, variations in nodal prices reflect the effects of policy and prices on consumer demand. For example, a significant increase in interconnection charges at the Whakamaru backbone node would cause demand to decrease at that node along with a corresponding reduction in transport costs at that node.

We have not undertaken any power flow analysis. Therefore, the CBA does not directly analyse:

a. intra-regional power flows

b. locations of losses by grid segment (such as the HVDC link)

c. changes in power flows due to new investment.

The reason why we have not done this is to limit the CBA's complexity – the same reasoning applies to the CBA not accounting for:

a. within-time zone variations in nodal prices and volumes

b. the indirect effect of LCE surpluses being indirectly returned to customers via the FTR process.

See our comments below on simplifications in the CBA.

Changes in transport costs cause changes to consumers' costs and benefits. For example, in the CBA grid use modelling, if peak demand increases then so do transport costs. The grid use modelling records this as a cost imposed on consumers. When, in a later step, the

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[10] Refer to: p.4 – questions 8, 9a-9d
p.12 – references 1, 2, 4, 5, 7-10
p.13 – references 11-13
p.14 – reference 14iii
p.15 – references 1, 2, 2i, 2iii.a), 2iii.c), 2iv-2v

CBA incorporates transmission investment costs due to higher peak demand, the increased transport costs from the higher peak demand are deducted. Amongst other things, this avoids the CBA double counting increased costs – i.e. both transport costs and the increased cost of transmission investment brought forward.

The CBA does not consider a single transmission investment or even several specific transmission investments. Rather the logic of the CBA is:

a. if peak demand rises under the proposal by more than it would under the baseline, this could bring forward transmission investment under the proposal, relative to the baseline. We assume the cost of any such transmission investment equals the difference in peak demand between the proposal and the baseline[11] multiplied by estimates of the long-run average incremental cost of transmission

b. as peak demand increases then so too does the cost of reduced transmission capacity (LCE). If we take account of the cost of transmission investment brought forward, we need to take account of the benefit of transmission investment brought forward. To do this, we assume the benefit is equal to the difference between transport costs under the proposal and under the baseline

c. over the CBA's 30-year assessment period, on average the difference between (a) and (b) is the incremental net cost or net benefit of bringing forward transmission investment across the entire interconnected transmission network under the proposal, relative to the baseline. It is not the cost or benefit for a specific transmission investment.

The transmission benefit from batteries, in terms of reduced transmission losses and constraints, is considered directly in the grid use model. When batteries are installed, peak grid demand declines. This reduces the LCE.

Note also that in reporting the costs and benefits of grid investment brought forward we take the median of modelling results (see previous response to this question posed at the webinar).[12] This approach is consistent with the reporting of results in the 2019 CBA. We could have instead taken the higher values for batteries and transmission investment at the median sensitivity, but that would not materially affect results. The results we report for the median scenario are consistent with the weighted mean results that are also reported.

Increased certainty for investors[13]

In response to question 11 in Appendix 1 of your letter, the Authority did not select parameters to produce a result that aligns with a particular view, either in assessing the benefits of increased investor certainty or any other part of its analysis.

The Authority confirms it considers that the proposal would improve investor certainty—the reasons for this are set out in the 2019 Issues Paper.

The CBA draws on estimates from international research to quantify the effects of reduced investment uncertainty. In the revised CBA we have halved, from 8.7% to 4.35%, the parameter controlling the response of investment to changes in uncertainty. We did this to

[11] We assume that equivalent increases in maximum peak demand under the proposal and the baseline cause equivalent (MW) incremental investment in transmission capacity.

[12] See footnote 8

[13] Refer to: p.5 – questions 11a-11b

increase the conservatism of the estimated potential benefit from improved investor certainty. Making this change acknowledges:

a. the parameter value used in the 2019 CBA came from a study into the effects of policy uncertainty in the United States of America, rather than in New Zealand

b. the measured value of 8.7% is an economy-wide value, rather than a value specific to the electricity industry.

Comments on simplifications in the CBA[14]

Several of Trustpower's questions in Appendix 2 are essentially an inquiry into what has not been analysed in the CBA rather than what has been analysed.

The CBA's modelling of interactions between demand and supply is of course a simplification of reality. Modelling by its nature seeks to provide a tractable representation (and not a replica) of what is a complex system. The Authority accepts there will always be different views about the assumptions and the approaches that could have been taken, and opportunities to refine the analysis.

For example, while the modelling accounts for adjustments in the dispatch of existing generation plant due to changes in operating costs, demand, and new generation investment, the modelling does not consider changes in generator offer strategies, or random plant outages and unit commitment issues, or dry year security of supply issues. On the demand side, the modelling does not account for demand response / demand shifting schemes. Also, the modelling does not incorporate reserves used for security and reliability purposes.

However, to the extent that simplifications such as these exist in the modelling, they exist in the analysis of both the proposal and the baseline against which the proposal is assessed. This equality of treatment between the proposal and the baseline helps to ensure the CBA modelling focuses on key effects arising from the proposed policy change.

We are confident the approach used in the CBA modelling appropriately identifies and quantifies key economic effects of the proposed changes to the structure of transmission prices. This includes accounting for the effect of changes in the structure of transmission prices on consumer welfare, arising from:

a. changes in wholesale electricity prices (inclusive of transmission charges) with no new investment in generation and/or transmission

b. changes in wholesale electricity prices (inclusive of transmission charges) and quantities of electricity consumed, following investment in new generation and/or transmission.

In our view, the CBA strikes a reasonable balance between complexity and simplicity. We are mindful that submissions on the 2019 Issues Paper criticised the CBA for being too complex. However, where submissions pointed to the need for additional complexity of

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[14] Refer to: p.9 – references 2, 2v (first reference to 2), 2 (second reference to 2), 3
p.10 – references 1i-1ii (first reference to 1), 1iii-1v (second reference to 1), 3i
p.11 - references 3iii-3iv, 4i-4ii, 5i-5iii
pp.11-12 – reference 1ii.a)
p.12 – references 2-3, 6

analysis (battery investment, generation investment and wholesale price formation) we have introduced additional complexity to the modelling.

There is practically no limit to the degree of complexity that could have been included in the CBA. We have not, for example, undertaken any power flow analysis. So, the CBA does not directly analyse intra-regional power flows, locations of losses by grid segment (such as the HVDC link), or changes in power flows due to new generation investment.

The CBA's grid use modelling is based on analysis of long-term annual average market activity broken down by 3 broad times of use, and an aggregation of grid nodes to 14 'backbone nodes'. Model data and nodal results thus reflect weighted average aggregations of activity (demand, supply, prices) over these aggregated nodes and time periods.

This modelling approach has a number of consequences:

a. it does not explicitly account for investment in peaking plant that operates infrequently and has short-run operating costs that typically exceed average wholesale energy prices during the peak periods modelled in the CBA

b. it is not possible to directly model real-time balancing of energy supply and demand or to analyse daily or seasonal supply fluctuations. When we analyse generation capacity and dispatch, we use adjustment factors to account for diversity of demand and offers. That is, the sum of average megawatts offered by generation plant, individually, will understate the average aggregate market megawatts offered, due to a positive correlation across individual generation plant capacities offered. The adjustment factors are deliberate and appropriate, and executed so that they do not cause an overstatement of benefits, or understatement of costs

c. we do not model operational (seasonal, daily, or hourly) variability in generation, including fluctuation in the availability of renewable generation, or hydro inflows/storage dynamics. Instead, we use fixed parameter values for typical annual average levels of activity, such as output or offers, based on empirical observations.

We note that our analysis of high-level, aggregated relationships is consistent with analyses in related contexts such MBIE's EDGS.

However, our approach brings distinctive advantages for the purpose at hand. Our analysis differs from similar quantitative or model-based analyses of future changes in electricity demand and supply insofar as the CBA considers:

a. dynamic changes in demand by time of use, location and consumer type, and

b. dynamic changes in transmission charges, alongside

c. analysis of changes in generation investment and changes in energy prices.

Other analyses typically model consumer demand separately from generation investment and market operation (dispatch and energy prices), and either ignore the effects that transmission prices have on demand and vice versa or assume that transmission charges are fixed (exogenous). That is, it is common, when modelling wholesale price formation and generation investment, to assume that future growth in peak demand (MW) and future growth in energy consumption (MWh) are both fixed (exogenous). This permits modellers to add considerable supply-side detail to their models and to solve those models using algorithms that approximate optimal operational (dispatch) and forward-looking investment decisions. However, this detail comes at a cost—it does not model consumer demand, nor does it model the effects of demand on transmission prices or the effects of transmission prices on demand.

One simple example of the pervasiveness of the fixed demand assumption is the estimation of long-run marginal costs of generation investment. Such calculations typically involve detailed assumptions about generation projects' technical operating parameters and input and capital costs. But they do not consider demand dynamics, even though costs are a function of demand and demand is a function of prices and prices are a function of costs. In other words, demand and costs are jointly determined.

In any case, it would not have been reasonable for a CBA of changes to transmission prices to have adopted the usual simplifying assumptions about demand because the effect of transmission prices on demand – and vice versa – is of central interest.

ELECTRICITY AUTHORITY
TE MANA HIKO

10 June 2020

Richard Sharp
GM Economic Regulation & Pricing
Vector Limited
Auckland

By email: richard.sharp@vector.co.nz

Dear Richard

RE: Transmission Pricing Review

Thank you for your letter dated 20 May 2020 to James Stevenson-Wallace.

As you will be aware, the Authority's Board has now released its decision to issue new TPM guidelines and a process for development of a proposed TPM. Prior to its decision, the Authority considered the various issues raised in your letter, as it has considered matters raised by stakeholders throughout the duration of its TPM process. Having considered your letter, the Authority remained satisfied with the process it has undertaken and its substantive position in respect of the TPM guidelines.

Process matters

In relation to the process concerns raised in your letter:

(a) The Authority remains of the view that its CBA is robust, notwithstanding the current COVID-19 pandemic. The Authority has kept matters relating to its CBA under review, including since the current pandemic became known. The potential impact of the COVID-19 pandemic and its appropriate treatment within a CBA evaluating transmission pricing options was considered explicitly in the CBA information paper. The Authority considers its sensitivity analysis was sufficiently extensive to account for a broad range of circumstances, including significant shifts in demand, such as a negative demand shock that might eventuate as a result of COVID-19.

(b) As to the impacts of COVID-19 on the Authority's process, the Authority notes that it conducted formal consultation on the 2019 Issues Paper and 2020 Supplementary Consultation Paper well before time and resource constraints as a result of the pandemic could have become a factor. The Authority considers that these processes were more than sufficient to allow it to make a decision on the TPM guidelines and process. In addition to these consultation processes, the Authority has also chosen to provide further information papers and a webinar on the CBA. The Authority considers the webinar was an adequate substitute for an in-person conference – participants could, and did, ask questions and make comments, with the Authority following up with answers to all questions asked. The Authority observed no impact on this process as a result of COVID-19 and received a wide range of detailed questions as part of this process.

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(c) As to the Tiwai Point Aluminium Smelter review, the Authority is of the view that it would be inappropriate to delay the TPM process to await the outcome of a decision by a commercial party, particularly given the Authority's finding that reform is necessary and urgent. Furthermore, as with the impacts of COVID-19, the Authority considers there is no strong reason to believe a significant negative demand shock, such as might arise with the closure of the aluminium smelter, would change the qualitative conclusions reached in the CBA.

(d) The Authority remains of the view that its formal consultation on the CBA and approach to peak charges under the TPM guidelines has been sufficient and consistent with good regulatory practice, and therefore determined not to conduct further formal consultation. In both cases, the information papers documented the Authority's current thinking with regard and in response to submissions and cross-submissions on the 2019 Issues Paper.

(e) As also noted in our response to the TPM Group, the Authority considers the revised CBA result to be a robust estimate of benefits. While the median estimate of benefits decreased as a result of the changes made, the estimates and the revised range of benefits remain within the range of benefits consulted on as part of the 2019 Issues Paper. As for CBAs associated with previous issues papers, the CBA associated with the 2019 Issues Paper represented a new approach and thus the results of previous CBAs are not relevant to its robustness. The Authority considers the 2020 CBA information paper provided enough detail to explain the changes, and the Authority also released the code, input and result files, and hosted a webinar to explain the changes and answer questions. An update of the 2019 CBA technical paper has been released with the Authority's decision paper.

(f) The Authority considers that its process for addressing stakeholder concerns has been more than sufficient. Having received a wide range of written and oral submissions on the 2019 Issues Paper, it has carefully considered all submissions and has provided detailed responses in respect of key issues (including those raised in your letter) in its decision paper. This is in addition to the information papers it has previously provided on peak charging and the CBA, as well as the detailed explanation of its original proposal in the 2019 Issues Paper. As a result, the Authority considers that it has provided more than adequate responses to matters raised by stakeholders.

The Authority therefore remains satisfied with the process it has undertaken in respect of the TPM guidelines.

Substantive matters

Prior to making its decision on the TPM guidelines, the Authority considered the substantive matters raised in your letter and its annexes. Having taken these matters into account, it determined to publish the new guidelines for the reasons set out in the decision paper.

In relation to the specific substantive points raised in your letter:

(a) The Authority considers that it has been very clear in its peak charging information paper on how, when and why the different charges can work together, for efficient use and investment decisions, and to manage what the Authority considers to be transitional risks raised in submissions. The Authority's approach was supported by Professor Hogan in his expert report for the Authority.

(b) The Authority disagrees that Professor Hogan's paper is based on an incomplete understanding of the Authority's approach or that Professor Hogan has mischaracterised the benefit-based charge. Rather, as is evident from his report, Professor Hogan's analysis is based on a clear understanding of the Authority's proposals, having for example reviewed the 2019 Issues Paper and consultant reports that came with submissions on the 2019 Issues Paper, and having also engaged in multiple exchanges with the Authority on our proposal.

(c) The Authority is satisfied that its CBA is robust and disagrees that it "suffers from serious problems that render it unreliable". Our CBA information paper sets out the Authority's thinking on where it agreed with submissions and revised its approach, but also where it disagreed, including on many of the issues that Vector repeats in its letter. This includes wealth transfers, distribution costs (and benefits), and different approaches to investment costs. In addition, we point out that, in contrast to Vector's critique, the CBA:

  (i) accounts for carbon costs, with modelled prices capturing emissions prices as noted a number of times in the CBA revisions paper

  (ii) captures the benefit-based charge's shadow prices, if anything overstating their effect (thus understating the proposal's benefits), as explained on page 29 of the CBA revisions paper

  (iii) finds price reductions under the proposal. Wholesale energy prices and generation input costs still rise, but not as fast under the baseline. The CBA results reflect the earlier generation investment under the proposal (consistent with long run energy supply being more elastic than supply in the short run)

  (iv) has an appropriate investment rule for a model that accommodates analysis of future changes in transmission prices and the effects on demand. It is unclear how it matters whether the rule does or does not allow for a specific thermal plant that is already being built, particularly given that rule operates in the same manner under both the baseline and alternative scenarios

  (v) reports typical modelling results in a manner that is unremarkable and consistent; these reported median results are also consistent with and very similar to the probability-weighted mean results reported in the same tables.

We thank Vector for its continued engagement in the TPM process.

Yours sincerely

Rob Bernau
General Manager Market Design