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Submission on Transmission pricing methodology: 2019 Issues Paper

ETNZ - The Energy Trusts Association - represents consumer and community owners of electricity distribution businesses throughout New Zealand. The trustees of these organisations are elected by electricity consumers, who are the beneficiaries of the trusts.

As the organisation representing those consumers and communities, ETNZ has both an asset owner and a consumer perspective in addressing this topic. We also have a focus on the efficient use of energy, reflecting s36 of the Energy Companies Act.

Is the Electricity Authority the appropriate party to complete this review?

The Issues Paper does not address legislative and policy issues that have a direct bearing on the efficiency of the transmission pricing methodology – notably the legislative right Transpower has to effectively tax consumers to recover sunk cost investments (such as NAaN) and, apparently, the policy of not charging Grid-reliant generators for the transport service that Transpower provides for them.

We recognise that, as a regulatory rather than a policy advisory body, the EA is bound to administer requirements of this type and to work within the constraints of those requirements. Accordingly, and given the significance of transmission pricing to the wider electricity industry and to the economy, we believe that it would be appropriate for an agency such as MBIE, with a central policy advisory function, to have a formal role in the TPM development process.

The transformative technologies now emerging in the electricity sector are creating an environment that is becoming increasingly removed from the one that existed when government policies and related legislation emerged, meaning that it would be timely for up-to-date policy advice to be provided to the Government before a new transmission pricing regime is put in place.

Can the CBA addressed in the Issues Paper be reconciled with the earlier CBA?

The EA has been prepared to move forward with the TPM on the basis of successive and, seemingly, very different cost-benefit analyses. While we recognise that the 2017 CBA was eventually found to include one or more flaws, it would be useful to see a reconciliation of the two, with the differences highlighted.

Without such a reconciliation it is impossible for us, and other interested parties, to be confident that the flaws that were identified have been adequately addressed.

On this point, the huge 'highest to 'lowest' spread of potential benefits identified in the new CBA (from $6.4 billion down to $200 million) is so large that its credibility is questionable. A small percentage shift in a key assumption could clearly make the lower estimate a negative number.

Other issues

The rest of our submission takes the form of responses to the questions posed in the Issues Paper (with the EA's questions and views identified in italics).

> *Chapter 2*
>
> *1.1 Have the problems with the current TPM been correctly identified? In what ways does the current TPM work well?*

We disagree that the problems with the current TPM have been correctly identified. In all cases, the descriptions of the primary problems either only identify some aspects of them or have a bias towards a particular solution.   Thus:

> *The current charges spread the costs of regional grid investments across all New Zealand. This makes such investments look cheaper than they are at the local level, compared to local alternatives, while other regions pay for assets they do not benefit from.*

First, it would be helpful to provide more granular data on the scale of the differentials in charges produced by the spreading of regional grid investment costs. The locational issues involved relate to the relative positions of generation and load around New Zealand, rather than just the location of regional loads. If the policy of not including generators in beneficial and residual charges is maintained, then it seems unreasonable to develop charges based only on the location of loads.

Second, we would like to see an analysis and discussion of the impacts on regional costs of the policy of protecting Transpower's revenue from write-downs of imprudent or premature investments. While the EA appears to be constrained by Transpower's right to recover its costs, policy-makers and consumers should be better informed on the costs imposed by this approach.

> *Interconnection charges are allocated based on consumption during just 100 regional peak trading periods in a year (the regional coincident peak demand or RCPD charge). This creates a very strong price signal to consumers, which:*
>
> > *o inefficiently discourages electricity use at times consumers most value it, even when there are no grid congestion issues*
> >
> > *o encourages customers to unnecessarily invest in technologies such as batteries and distributed generation to avoid paying transmission charges, shifting charges to others without reducing Transpower's costs.*

To us this is an unnecessarily Transpower-centric representation, overlooking the fact that Transpower is part of a wider electricity system that includes consumers, distributors and other downstream players. As a general rule demand peaks create additional consumer costs, and it would be consistent with the EA's primary objective to seek outcomes that involve Transpower pricing to reinforce the overall efficiency of the electricity supply and consumption chain. Instead, the above view is being used as a rationale for reducing peak transmission charges.

The impacts of shifting away from peak-based transmission pricing include encouraging additional use of more expensive thermal plant at peak times, rather than promoting demand-side options to reduce load. This is not an outcome that is necessarily favourable to consumers or to the environment.

While the CBA finds very significant benefits in reducing the scope for batteries to be used to shift load away from peaks, its analysis seems to be blind to the parallel impacts of this approach:

- Batteries have the added advantages of helping to maintain supply through short-term interruptions;

- Batteries are mobile, meaning that they can be relocated as loads change and as other dynamic shifts occur;

- Use of batteries at peak times is likely to reduce line losses, which rise very significantly at those times;

- Use of batteries to reduce peaks should also lead to significant saving to consumers through lower nodal prices, assuming that the market works efficiently;

- Avoiding constraints associated with peaks implies more aggressive competition among retailers, who would be less constrained by the threat of having to find cover for higher wholesale energy costs at times when consumer demand is highest.

> *South Island generators pay for all of the costs of the high voltage direct current (HVDC) line that transports electricity between the South and North Islands, though North Island generation does not face equivalent charges. This 'tax' on South Island generation encourages investment in otherwise more expensive North Island generation.*

The wider problem involved here is the current practice of not charging other grid-dependant generators for use of the transmission system (beyond cost recovery of connection assets). Representing the HVDC charge as a 'tax' is something of a misconstruction, as in fact it is simply a rather crude application of normal charging services that should apply to any party using a system to get its products to market.

Applying the HVDC charge to South Island generators has meant that the generators who get the most benefit from the assets connecting them to the North Island are exposed to a portion of the transport costs that they are otherwise exempted from. Removing the market pressure that this creates (especially at the competitive interface between energy from water in the South Island lakes and generation and energy efficiency options at the consumption end) would therefore not be to the long-term benefit of consumers.

Instead, to the extent that anomalies are created by the current HVDC charge, we suggest that the EA looks for a formula that loads the HVDC costs onto the generators who get the clearest benefit from the inter-Island energy flows.

> *Chapter 3*
> *I.2 What are your overall views on the Authority's proposal for changes to the TPM guidelines?*

The guidelines do not seem to address the problem of future regulatory errors, such as over-estimation of demand growth. Such errors are familiar already (e.g. NAaN) and the EA view that it is valuable to have transmission customers exposed to such costs so that they will look hard at underlying assumptions is an unsatisfactory response.

Certainly, if Grid-reliant generators faced the costs of imprudent transmission investments then they could be expected to look carefully at the economics of future investments in supply. However, this benefit to consumers is not considered in the proposed TPM.

In contrast, downstream customers – mainly distributors – have large numbers of customers with varying needs, and are exposed to uncertainties outside their control (such as the loss of a major factory, population & climate changes, etc.) and invariably have imperfect information from load segments.

In these circumstances Transpower and the regulator are by far the best informed and best-placed parties to make a decision on Grid investments. Unfortunately, if there is no cost recovery sanction on Transpower, their tendency will be to over-estimate demand, knowing that they are exposed to political sanctions if they under-build. This is another area where a legislative change that exposes Transpower to the consequences of over-investment might usefully be considered to ensure correct transmission outcomes. This is another issue where a policy review by an agency such as MBIE would be desirable.

Beyond this ETNZ is not well-placed to comment in depth on the guidelines. However, several of these have adverse or counter-intuitive consumer impacts that we question, such as the approach taken to the price cap:

> *50. Subject to clause 53, in setting a price cap, the TPM must provide for:*
>
> *(i) any increase in a distributor's transmission charges subject to the*

price cap as set out in clause 49, as compared to its transmission charges minus its connection charges in the 2019/20 pricing year, to be limited to no more than the amount resulting from the following formula:

B x (0.035 + CPI + L)

where:

B is Transpower's estimate of the total electricity bill for all consumers supplied, directly or indirectly, from the distributor's network in the 2019/20 pricing year (expressed in dollars), calculated as:

*B = C + P*V*

and where

CPI is the change in the Consumer Price Index since the 2019/20 pricing year (expressed as a decimal);

L is the increase in the distributor's load since the 2019/20 pricing year, if any (expressed as a decimal);

C is the distributor's total line charge revenue for the 2019/20 pricing year excluding GST from Schedule 8 Report on Billed Quantities and Line Charges Revenues of the Electricity Distribution Information Disclosure Determination 2012;

P is the volume weighted average of wholesale energy prices at the distributor's grid exit point or points for the 5 years up to and including the 2019/20 pricing year from the Authority's Electricity Market Information database, expressed in $/MWh and excluding GST, with weights being the gross load as determined by the reconciliation manager; and

V is the distributor's total gross load for the 2019/20 pricing year, expressed in MWh, as determined by the reconciliation manager;

This relatively complex formula makes the price cap far from transparent. We can see no useful reason for attempting to link a cap on transmission price increases to something more than the actual transmission price, plus an adjustment for inflation. Building in a proxy for the wholesale price of electricity, along with distribution charges, simply gives a misleading impression that the maximum transmission price increase will only be 3.5%, when it may well be double that or more. The EA view that customers tend to focus just on the impact on their delivered cost misses the point that customers will not be able to also understand the transmission component if it is not transparent. Such transparency would place some pressure on Transpower to control cost increases.

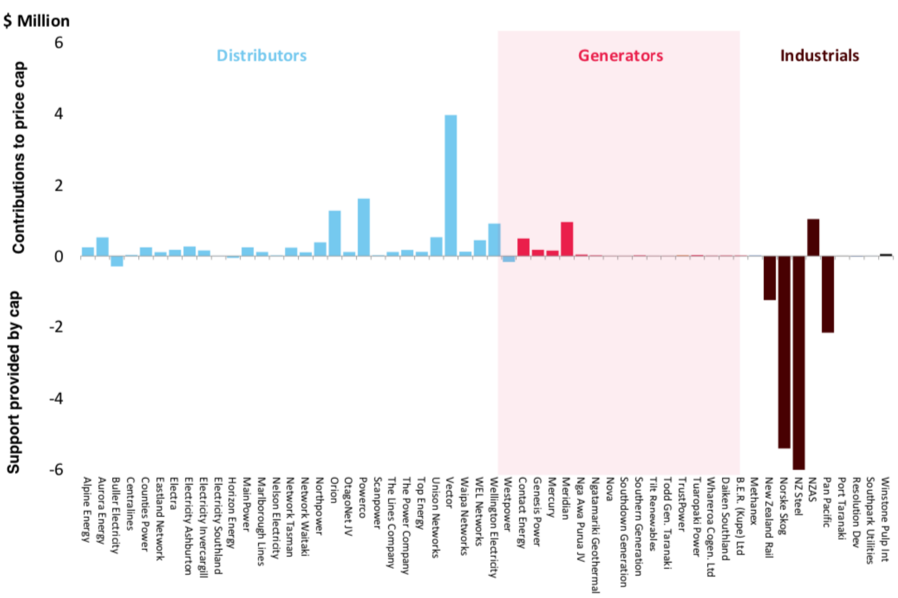
> *51. To the extent that the price cap results in a reduction in transmission charges for one or more load customers, the revenue so forgone is to be recovered by a surcharge on and proportional to the total of the benefit-based charge for the investments listed in clause 13(b) and the residual charge for each designated transmission customer.*

First a 'price cap' should also be a revenue cap, rather than an allocation mechanism, if it to provide the correct efficiency signals to all parties. While this could be seen as a threat to Transpower's supposed entitlement to recover its forecast MAR, it would be better to view it as a signal to Transpower to encourage prudent investment (or other behaviour) to reduce the charges being capped, rather than a signal to simply pass on the costs of potentially inadequate or imprudent investments to distributors and consumers.

Second, excluding connection assets from the proposed reallocation would appear to make the current and proposed cross-subsidy from distributors and consumers to grid-dependant generators even larger. Again, this is an inefficient signal that loads costs onto consumers.

Third, it appears that the multi-tiered approach to applying the price cap involves a significant wealth transfer from distributors and their customers to industrial loads (at least for the first 5 years):

Figure 14: Indicative contributions to, or support from, the cap in 2022



Furthermore, presumably the contribution apportioned to generators will be transferred to distributors once (as proposed) the HVDC costs are also transferred to them. We cannot see any justification for such wealth transfers, which are incompatible with the EA's statutory objective. Perhaps a single capping mechanism simply applied to each GXP would produce a less distortionary outcome.

> *Chapter 4*
>
> *I.3 Does the CBA provide a reasonable estimate of the costs and benefits of the proposal? If not, what changes to the methodology and / or assumptions would improve the estimate?* and
> *I.4 Do you have any comments on the matters covered in chapter 4?*

We note that the 'Cost categories' identified in the CBA (with the possible exception of *Suppressed demand from customers with uncapped charges*) are all internal costs either for Transpower or for the TPM implementation and operation processes. There does not appear to be any assessment or recognition of the costs that the proposed TPM may impose on consumers and other parties.

For example, the reduction in peak signals may impose additional costs on consumers due to a need to reinforce distribution systems. Similarly, consumers may miss out on efficiency gains due to the increased pressures created to use Grid-supplied electricity rather than demand-side options.

Energy efficiency impacts are also excluded from the costs recognised in the CBA. The reduced peak signaling implies additional line losses, as does the focus on discouraging the stranding of sunk cost transmission assets.

As well as having doubts about the merits of a CBA where the main benefits don't become apparent until around a decade out we are understandably cynical about 4 of the 5 'Benefit categories', i.e. the ones associated with "More efficient…" behaviours (*More efficient investment by generators and large consumers*, etc.). No matter how detailed the underlying spreadsheets are, assumptions about efficiency gains are necessarily very subjective. Predictions of wide-ranging human behaviours over several decades will invariably have huge margins of error. Here we note the regulatory errors that have already been acknowledged about NAaN, etc.

The 5th 'Benefit category' (*Increased certainty for investors*) is equally subjective. In addition, it doesn't take into account the reduction in certainty that downstream investors (especially parties considering investing in new technologies) will face.

Chapter 6

We have no comment on questions I5 – I12

Benefit-based charge

I.13 Do you think introducing a benefit-based charge for future grid investments will promote efficiency and the long-term benefit of consumers?

We would feel more confident that consumer benefit would result if Grid-dependent generators were also identified as parties benefiting from this charge. This would place greater pressure on the mainstream generators to cut prices to meet competition from technologies such as solar power and other non-Grid options.

I.14 Should the cost of pre-2019 investments be recovered in some other manner than through the residual charge, and if so how? Which pre-2019 investments should be recovered in this manner? In particular, do you consider that the cost of some past investments should be recovered through a benefit-based charge?

There is a lack of transparency about the cost of consumers of continuing to pay for redundant or over-built transmission assets that would be written down in a realistic market situation. We believe that greater efficiency would be promoted if that cost were to be clearly identified as a discrete charge component.

Such an approach would help potential investors identify regions where surplus transmission capacity is available, and would also help consumers and policy-makers to review the consumer benefit/disbenefit of the legislative obligation to continue to pay for unnecessary assets.

Residual charge

We are concerned that there are no strong signals to Transpower to reduce line losses under the residual charge proposals, regardless of whether a gross load or net load approach is adopted. We believe that it would be consistent with wider government policies (including climate change objectives) for Transpower to face a financial penalty if such losses rise, regardless of the MAR. If this requires a legislative change then we can see no reason why such a change should not be recommended.

We also believe that Transpower should face stronger signals to reduce peaks. If it is insulated from financial signals through the proposed benefit charge/residual charge see-sawing arrangement then this will invite indifferent behavior, at the expense of consumers and of the environment.

Appendix C

I.49 Do you have any comments on the matters covered in this appendix C?

We agree with the Authority that there have been material changes in circumstances since the current TPM was adopted. However, we also recognise that the electricity industry is on the cusp of undergoing significantly more material changes over the next few years as new technologies are adopted and as consumers and other parties become more empowered to widen their participation.

As indicated on page 1 of this submission, we believe that it would be in the long-term interests of consumers to have a policy advisor, such as MBIE, now assess whether legislative and other high level issues need to be reconsidered in the in the light of these changing circumstances. This should occur before that TPM process moves forward. We would also recommend that the views of the Ministry for the Environment, and of EECA, be considered on the proposed reduction in peak load signalling.

Appendix D … Appendix E

I.56. Do you agree that the benefit-based charge, in conjunction with the Commerce Commission regulatory regime and nodal prices, is sufficient to ensure efficient investment in the grid and by grid users?

As stated above, we would have more confidence in the benefit charge providing efficient signals if it applied to grid-dependent generators too.

Nodal prices deliver misleading investment signals, as nodal price rises evaporate as soon as load is reduced by demand-side actions or local generation investment. In contrast, nodal prices provide immediate benefits to grid-dependent generators, as prices spike when transmission is constrained and line losses are highest.

As far as the Commerce Commission's regime goes, we would be comforted to see a ComCom review of the proposed TPM with a view to identifying any price maintenance elements or other features that impede competition.

We have no other comments on these 2 appendices.

> *Appendix F*
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> *I.62 Would the proposed ACOT Code change be desirable to clarify the situation for payment of ACOT under the TPM proposal? Would the resulting code provisions in relation to ACOT be efficient?*

The Issues paper does not attempt to quantify the differences in ACOT payments under the existing TPM vs the proposed TPM. This is a very important issue to current ACOT recipients and to distributed generators in general. ETNZ notes that ACOT, despite some inconsistencies, is the only significant arrangement that helps address the Commerce Act's s54Q requirement:

> **54Q Energy efficiency**
>
> The Commission must promote incentives, and must avoid imposing disincentives, for suppliers of electricity lines services to invest in energy efficiency and demand side management, and to reduce energy losses, when applying this Part in relation to electricity lines services.

If the value of ACOT payments for distributed generation is reduced or the allocation changed under the proposed TPM then the incentive it provides to distributors to invest in local generation that reduces line losses, and in associated technologies that promote demand-side management, will be reduced or changed accordingly.

We would like clarity on the relative value to different parties of the proposed ACOT Code change before we can reach an informed position on this issue.

l.63 Do you agree that this potential Code amendment to ensure the workability of the TPM will reduce uncertainty? If not, do you think it can be modified so as to ensure uncertainty is reduced? If so, how?

If the proposed amendment reduces uncertainty by imposing damaging rigidity then we would prefer to see further consultation on how ACOT might be modified to ensure greater consumer benefit. In particular, it would be useful to consider how ACOT might be enhanced to support the objectives of s54Q.

Appendix G
l.65 Do you have any comments on the matters covered in this appendix G?

We have no views on Appendix G other than those expressed elsewhere in our submission.

Appendix H

We have no comments on Appendix H other than those expressed elsewhere in our submission.

Karen Sherry
Chair, ETNZ