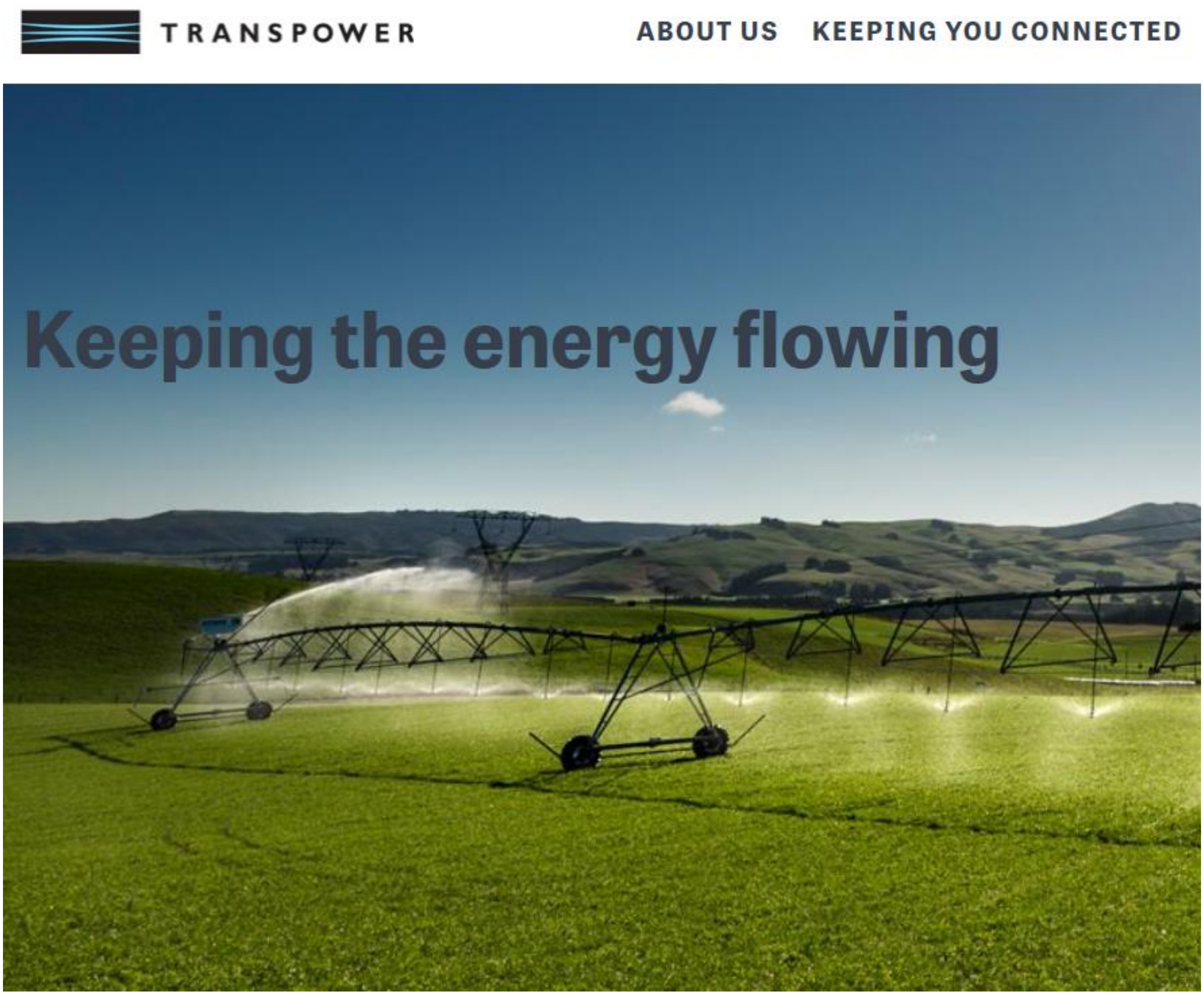
# Electra Limited Submission on

# The Electricity Authority 2019 Issues Paper

# *Transmission Pricing Review*

# 1 October 2019

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# 1 Summary

The Electricity Authority has proposed a Transmission Pricing Methodology (TPM) that aims to address current pricing structures that encourage inefficient generation and transmission use. The Authority recognises it will result in higher peak demand and most benefits are not delivered until after 2032.

While the principles of the proposed TPM may be theoretically sound, the proposal carries significant risks:

- ***Signalling for investment is weaker and more volatile;*** Switching to real time nodal prices (which signal demand driven constraints and drive short term generation availability) to drive long lead time transmission investment, is poorly matched to the long-term planning required. It may be too weak and unclear and its practical effectiveness is uncertain.
- ***Transmission Investment will take longer;*** Challenge and debate of transmission investments are encouraged in the proposed TPM and will result in delayed investment to mitigate high real time nodal prices. This may create situations where high nodal prices can be exploited and transmission investment blocked by quick to implement, less efficient technologies.
- ***Accelerated transmission investment needed;*** The Authority recognises its proposal will increase peak demand and transmission capacity investments will need to accelerate in an environment of greater challenge and litigation.
- ***Consequential distribution costs are excluded;*** Demand peaks will increase but the estimated benefits have explicitly excluded consequential costs required to strengthen distribution networks.
- ***Longer periods of higher prices;*** With longer transmission development lead times repetitive nodal constraints may exist for longer.
- ***Farming of higher prices;*** distributed generation and batteries have an enhanced opportunity to gain reward from high nodal prices, incentivising behaviours to create them.
- ***Higher costs on implementation****; no material estimated benefit for a decade;* The proposed TPM will introduce higher initial costs and the EA estimates that it will not deliver any material benefit until after 2032.
- ***Benefits are overstated;*** The largest portion of the estimated benefits are derived from eventual generation investment in response to high wholesale energy prices. When new generation comes on line, energy prices will moderate somewhat. Most of the price moderation will happen in any case, the TPM cannot claim to deliver all of this benefit.
- ***Costs and price averaging shifted to regional generators;*** The business model of distributed generation has been impaired. This regulatory volatility will stall investment in this sector.
- ***Broader business and social impacts excluded;*** The Authority may feel it has complied with its statutory objective however it is notable that significant impacts occur in regions where they are least affordable.
- ***Allocation of residual costs;*** Basing allocation on energy rather than demand shares costs across generation and load users of transmission services in proportion to their activities, encouraging downward pressure on distribution and generation prices.

These risks cannot be ignored, they will need to be eliminated or managed for the long-term benefit of consumers.

Contents

# 2 Introduction

The EA is seeking to introduce a new TPM to address:

- Peak pricing that encourages more efficient use of the Transmission grid and removes incentives for cost avoidance behaviour that merely shifts costs to other customers.
- Recovers HVDC costs from customers that benefit from it, rather than customers of South Island Generators

Electra participated in the Introductory and Technical workshops hosted by the EA and discussed observations with a range of generation, distribution and industrial stakeholders.

In relation to the Issues Paper Electra has noted key themes that it recommends the EA integrate in its development of new components in a Transmission Pricing Methodology.

The EA cites $2.7 billion of benefit to New Zealand through to 2040, principally through efficient generation location and transmission system use.

# 3 High Level Components of Existing and Proposed TPM

The current TPM comprises four categories of charges:

- An HVDC Charge (borne by South Island Generators)
- Connection Charges relating to assets dedicated to a customer or small number of customers
- New Investment Contract Charges borne by the customer that has requested additional assets (eg an additional feeder)
- Interconnection Charges comprising costs and return on investment not recovered in the above charges. Interconnection Charges are shared amongst Transpower customers in proportion to their contribution to the 100 highest demand peaks in their respective region over the previous year.

The proposed TPM does away with the HVDC Charge and the Interconnection Charge. The other two charges are unchanged.

Two new charges are proposed:

- A Benefits Charge shared amongst customers that have benefited from Transmission investments. A handful of major historic investments have been proposed for the introduction of a Benefits Charge.
- A Residual Charge comprising costs and return on investment not otherwise recovered.

Over time as assets depreciate and new investments are implemented, the Residual Charge decrease and the Benefits Charge will increase.

The Authority considers that its proposed TPM guidelines would better promote its statutory objective in section 15 of the Electricity Industry Act (Act), in particular by promoting the efficient operation of the electricity industry for the long-term benefit of consumers.

Section 15 reads, in full; The objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

# 4 Nodal Pricing

The EA is concerned that the current peak demand signal is too strong and is driving inefficient investment in generation strongly focussed on revenue from peak avoidance and the Avoided Cost of Transmission (ACOT) and consequently other connected parties share a higher proportion of the required transmission charges.

Additionally, the EA claims that such Generation investments are poorly located, inefficient and lead to inefficient use of the Transmission system.

The EA proposes that nodal pricing is a better signal for supply constraints and leads to more efficient Generation and Transmission investment.

## 4.1 Longer periods of higher nodal prices

The development lead time of transmission or generation investments may result in prolonged periods of constraint pricing events resulting in prolonged exposure of retailers and spot market customers to higher prices.

Combined with incentives for customer challenge of Transmission charges associated with allocation of benefits, the development lead times are sure to be lengthened, posing greater risk to reliability or higher prices for longer periods until investment plans are finalised (if not universally agreed) and the solution implemented.

## 4.2 Less efficient investment encouraged

The fleeting and short duration nature of Nodal pricing encourages short lead time lower cost mitigations, such as batteries that the issues paper has identified as inefficient and not expected until 2027. When implemented these may effectively block the longer lead time more efficient transmission solutions.

## 4.3 Farming nodal constraints

One type of avoidance behaviour may be reduced but another incentivised by creating situations that encourage faster to implement, less economically efficient mitigations of nodal price spikes. The guidelines should seek to discourage cost shifting and inefficient investment but also be mindful of, and responsive to, the risks incentivising unintended consequences.

The EA's proposed changes to nodal pricing and benefit allocation seek to improve investment efficiency in a period when new energy resources are expected to manifest. Also, there are significant changes expected in the use of electricity to replace carbon fuels. These changes have inherent uncertainties in the technology, adoption behaviour and adoption timelines. The goal of an enduring pricing methodology in light of the uncertainties of being able to make the proposed changes work effectively may be better implemented as a phased transition targeting the goals outlined, allowing participants to effectively adjust, particularly with respect to the effectiveness of nodal pricing or an alternative constraint driven investment signal.

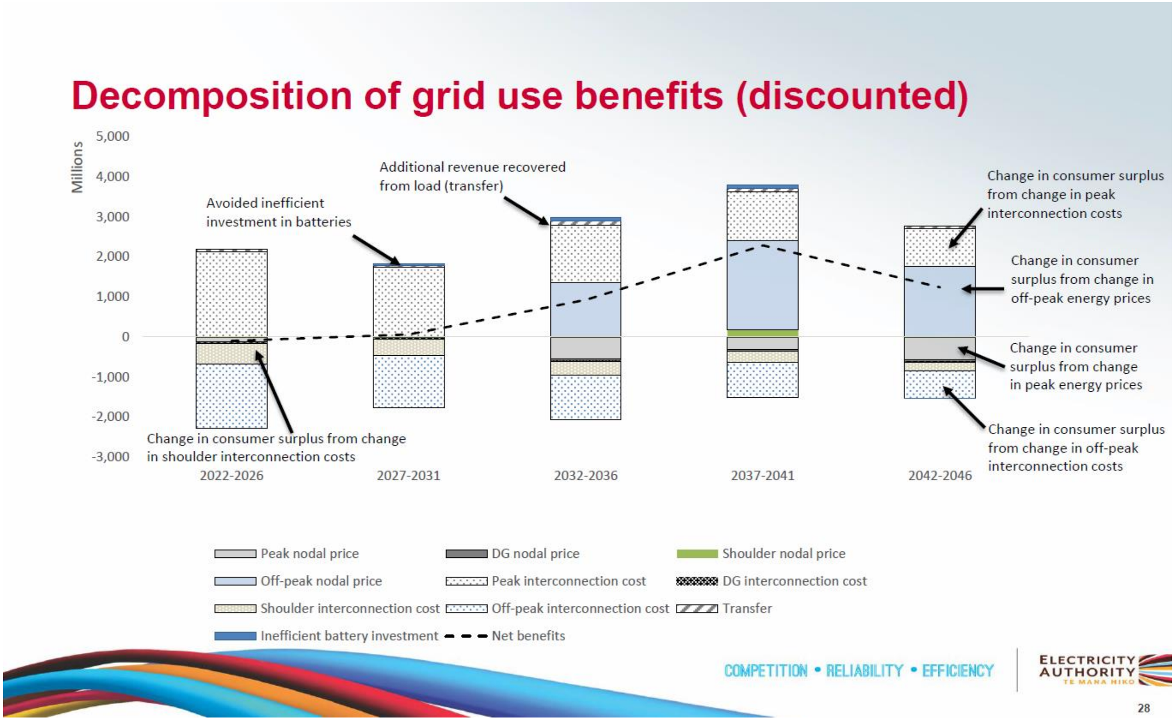
Introduction should be tempered rather than ambitiously optimistic, in order to mitigate risk and improve investment efficiency, investment effectiveness, and introduce benefit charging.

# 5 Assessed Benefits

The majority of estimated benefits ($2.7 b), do not start accruing until 2032. The primary driver of this, according to the figures in the EA's analysis, is the fall in the off-peak nodal price, brought about by increases in generation investment. Further, there are no estimated benefits delivered to customers until 2027, five years after proposed implementation. Indeed, there are higher costs from implementation until 2027.

The $2.3 b of estimated benefits from more efficient grid use and the energy price being moderated from $100/MWh to $70/MWh appear overstated. New generation will be built to meet demand and new generation will moderate the prospective spot price but energy prices will rise to earn a return on the new generation. In short, more efficient location of generation and grid use cannot claim to be delivering all of the estimated $30/MWh benefit.

Benefits are estimated to start to accrue over ten years from now should be seen as indicative and this support a steady implementation of contemporary pricing principles rather than a one-off set of changes aimed at being fit for purpose a decade from now for an electricity industry environment that is undergoing change now, and, that change is expected to accelerate.




# 6 Benefit cost sharing

The idea of the beneficiaries of transmission investment paying for it is simple, though the range of unassessed consequences represent risk to NZ economic and social activities.

In some cases, the higher Distributor charges may be offset by discontinued ACOT payments by the Distributor to regional generation, nonetheless there will still be regional impacts and these will be felt worse, where they are least affordable.

# 7 Benefit Assessment and Challenge Process

The largest benefits are the most contentious, most speculative, and furthest out into the future. Even if the EA's CBA is correct, which we dispute – the costs and disruptions come almost a decade before material benefits.

The level of challenge regarding allocation of benefit costs are at risk of increasing, compromising or negating the benefits aspired for the respective beneficiaries in particular and New Zealand as a whole.

The proposed TPM invites challenge of proposed Transmission investment by beneficiaries, citing 4% savings through more efficient eventual investment solutions. This will increase the effort required of beneficiaries to challenge investment proposals and likely claim other beneficiaries should bear more of the costs.

There are opportunities to make improvements in the TPM while avoiding introducing risks of increased litigation, delays to investment decisions, lower productivity and incentivising short term inefficient constraint mitigations. There is time for phased implementation of the guiding principles and objectives

Transmission investment projects will be litigious, creating opportunity for inefficient constraint management and potential farming of nodal energy prices opportunities.

# 8 Direct Impact on Electra Customers

Using the figures from the EA's Issues Paper[1], Electra charges for each customer connection will increase on average $8.66 per year after ACOT benefit sharing with distributed generation ceases. Section 5.44 of the Issues Paper is not correct when it estimates costs per Electra customer will be lower as a result of the proposed TPM.

# 9 Consequential Impacts on Distribution

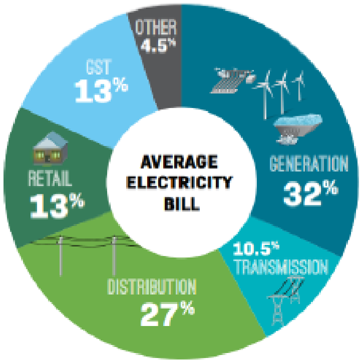
The EA seeks to facilitate energy use during peak times "when customers most value it" by replacing current peak pricing with a weaker nodal price signal. However, consequential impacts from higher peaks on Distribution systems and investment have been excluded from this Transmission focussed proposal.

The EA is required to focus on efficient operation of the electricity industry, though the modelling assumption that the Distribution networks have spare capacity for even a modest change in peak demand behaviour is fraught with risk. In many cases there will be Distribution constraints that will need to be continued to be managed, preventing the EA's goal of unconstrained consumer use of energy during peaks.

The absence of analysis of consequential impacts in Distribution needs to be addressed as it has the potential to be significant in a sector that the EA cites as already making up 27% of a residential customer's electricity bill. Refer EA figure 15 below.

[1] Electricity Authority, 2019 Issues Paper, Transmission Pricing Review, p61, Table 12

Figure 15: Transmission charges as part of the average residential electricity bill




## 10 Impact on Distributed Generation Investment

The uncertainty introduced by such volatile regulatory change, which has significantly impaired the business model of existing distributed generation, will discourage long term investment because of the risk of such volatile change occurring again. Regulation is about management of risks and introduction of changed regulation should support this.

## 11 Other Benefits and Impacts

The EA's particular focus on efficient Transmission and Generation investment and the benefits to New Zealand from this does not reflect on the interaction of these costs and benefits with other types of benefits.

It would be useful to have commentary from the EA on how the proposed TPM contemporary and future energy objectives of the Government as well as how it is envisaged that the TPM will complement the objectives of the Commerce Commission.

It is not suggested that the EA has the obligation or skills to assess the positive and negative effects with broader benefits and costs, however shifting the balance of where costs are borne and benefits enjoyed should invite input from expertise in assessing broader economic and social impacts on wealth and welfare.

Notably, there are a number of regions with lower concentrations of wealth that have been nominated to pay significantly higher transmission charges, albeit some with capped rates of increase.

## 12 Postage stamp pricing

Postage stamp pricing (averaging costs) is cited as a flaw to be corrected and it is proposed to do so by reallocating HVDC Cost recovery from South Island generation to EDBs and direct connect customers according to an assessment of benefits they derive from the HVDC.

How does the EA reconcile this with the apparent contradiction of removal of ACOT arrangements and regional generators baring higher costs – leading to higher postage stamp pricing from the regional generators?

## 13 Netting off Embedded Generation and DER

Referencing the EA's reliability objective, it would seem reasonable to net off all energy sources that meet equivalent transmission availability and capacity criteria. Eg if the capacity of a tripped energy source can be made up by other available sources and its tripping does not result in lost load then it may be netted off.

Cogeneration linked to a production process could be netted off if the production process gross demand was reduced in the absence or non-availability of the cogeneration.

## 14 Basis of Apportioning Residual Charge

EA has used gross MW demand of load customers to apportion recovery of residual costs in the proposed TPM and seeks feedback on whether an alternative basis should be used, for example MWh.

A benefit of using MWh flowing through transmission assets and sharing the costs proportionally with generation and load customer would actual use of system by participants, incentivise efficient use of energy and keep downward pressure on generation and distribution prices.

## 15 Conclusions

The Electricity Authority seeks to adjust transmission charges to encourage efficient grid use and discourage cost redirection. However, of considerable concern are the highlighted risks associated with:

- Effective implementation and operation, in respect of;
    - Practicality of the weaker peak pricing signal
    - Additional lead time resulting from litigation of benefits allocation,
- Including generation price benefits that are not wholly derived from the TPM,
- The TPM adds (small) cost immediately while there are no material benefits realised for a decade after implementation,
- Uncertainty of actually realising benefits based on current assumptions of future energy technology and its adoption,
- Impact of additional costs on some regions and industries,
- Impact of additional costs on smaller generation businesses. This regulatory volatility will stall investment in this sector in particular, but also the industry more broadly.
- The need to accelerate transmission investment to support higher demand encouraged by weaker demand management signals,
- Consequential need for greater distribution investment resulting from weaker demand management signals,
- Unintended creation of the opportunity to harvest revenue from nodal constraints by less efficient DER.
- Longer transmission development lead times resulting in repetitive nodal constraints existing for longer.
- The benefits claimed from eventual additional generation cannot all be attributed to the proposed TPM
- The Authority may feel it has complied with its statutory objective however it is notable that significant impacts occur in regions where they are least affordable.

- Basing allocation on energy rather than demand shares costs across generation and load users of transmission services in proportion to their activities, encouraging downward pressure on distribution and generation prices.

# 16 Recommendations

- Provide clarity on how nodal pricing and benefits charging will effectively drive timely efficient investment,
- Bring forward benefit realisation if possible and at least commit to monitoring progress towards benefit realisation and tightening the estimate envelope of benefits as progress is made,
- Include an estimate for consequential distribution investment,
- Outline how unintended negative consequences will be responded to,
- Provide clarity on how EA, ComCom and Transpower activities will operate a coordinated investment proposal and approval process.