2019 issues paper

Transmission pricing review

EXECUTIVE SUMMARY

Consultation paper

23 July 2019

Executive summary

A new approach to transmission pricing for the long-term benefit of consumers

The Electricity Authority (Authority) is proposing a new approach to transmission pricing. The Authority considers that changing the transmission pricing methodology (TPM) is necessary and becoming increasingly urgent.

The current TPM enables Transpower to recover its maximum allowable revenue, and signals to customers that their demand drives future investment in transmission capacity. In this way the transmission charges to some extent help to defer costly grid investments.

However, significant flaws in the TPM are leading to inefficient investment and consumption outcomes:

- 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.
- 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:
  - inefficiently discourages electricity use at times consumers most value it, even when there are no grid congestion issues
  - 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.
- 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.[1]

These problems increase cost to consumers. They are likely to get worse as more grid investments are made to support growing regions and the transition to a low-emissions economy, and as distributed generation, such as solar panels, and batteries become more affordable.

If the RCPD is left unchanged, there is a very real risk of a substantial shifting of charges by households with the resources to take up these emerging technologies at scale. This accelerating shifting of charges will increasingly expose remaining households to RCPD price signals. That will increase their incentives to try to avoid these charges through inefficient investment. If we do not act now, consumers will get less benefit from the electricity system and pay more for it in the long-run.

The proposed TPM guidelines seek to address these problems. The Authority considers that a TPM consistent with the proposed TPM guidelines would unlock considerable long-term net benefits for consumers.

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[1] Some of these issues date to the late 1990s, when pricing was introduced that allocated costs of the HVDC in full to South Island generators and allocated interconnection charges on a measure of peak demand only.

Benefit-based transmission pricing

The Authority proposes a benefit-based approach to allocating transmission costs, where those who benefit from specific grid investments would pay for them. Key features of the proposal are:

- a benefit-based charge to recover costs of new grid investments and depreciated costs of seven major existing investments[2] based on their benefits to transmission customers
- a residual charge to recover any remaining transmission costs in a manner which does not distort incentives to invest or use the grid.

These new charges would replace the current RCPD and HVDC charges. They are purposely designed to be independent of grid use and so hard to avoid. This would mirror Transpower's own cost structures which are largely fixed and not dependent on grid use. The proposed charges would therefore minimise inefficient grid use and inefficient investments.

These new charges would send better signals to consumers about the economic cost of using the grid, without distorting grid use or investment in grid-connected generation and transmission alternatives. This approach is aligned with the new distribution pricing principles that the Authority released recently, which guide distributors in adopting cost-reflective network pricing.[3]

The guidelines in respect of the connection charge[4] are proposed to remain largely unchanged, while some minor modifications are being proposed to the current prudent discount policy.[5]

Wholesale market prices will work alongside the TPM to manage peaks

The Authority recognises that some form of peak pricing will continue to play a key role in the management of demand in the case of congestion, and to defer grid investment until the timing is right. The design of such a charge has been a topic of much consideration (see Appendix E).

The Authority considers that the well-established mechanisms adopted in 1996 by New Zealand to determine wholesale market prices at grid injection and exit points (nodal or locational marginal pricing) deliver the most responsive and efficient signal of transmission costs and congestion. As the International Energy Authority has stated:

> "Locational marginal pricing (LMP) is the electricity spot pricing model that serves as the benchmark for market design – the textbook ideal that should be the target for policy makers. A trading arrangement based on LMP takes all relevant generation and transmission costs appropriately into account and hence supports optimal investments".[6]

Nodal prices can do a better, more targeted job of providing a timely signal of the actual cost of using the grid (such as congestion) at specific locations than the blunt and typically excessive signal currently provided by the RCPD charge or an alternative long-run marginal cost (LRMC) charge.

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[2] The HVDC, North Island Grid Upgrade, Upper North Island Dynamic Reactive Support, Wairakei Ring, Bunnythorpe-Haywards Reconducturing, Lower South Island Reliability, and Lower South Island Renewables.

[3] The principles are published in our distribution pricing decision paper at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/distribution-pricing-review/development/summary-of-submissions-and-decision-paper/

[4] Recovers the costs of assets that connect transmission customers to the transmission grid.

[5] A discount to avoid a customer disconnecting from the grid, which would raise costs to others.

[6] International Energy Agency (2007). All academic references are cited in full in the Bibliography.

The Authority is of the view that the increasing uptake of emerging technologies by consumers, the introduction of real-time pricing, and the emergence of new business models will make nodal pricing an increasingly responsive and efficient tool to manage grid congestion.

This approach avoids the costs under the RCPD charge of discouraging consumers from making use of the grid where there is spare capacity available, as currently happens. It would only generate higher prices where grid congestion exists, until prices indicate that grid investment is efficient.

The Authority acknowledges there is some uncertainty regarding the immediate impact of removing the RCPD charge. For example, it is not known with certainty how distributors would adapt their demand response programs, such as ripple control of hot water tanks.

In response, the proposal also provides an option for Transpower to introduce a transitional peak charge, to operate alongside nodal prices, at specific points in the grid that would otherwise experience congestion. However, the Authority considers any need for a separate peak transmission charge will disappear over time, as new demand response arrangements emerge with the support of new technology and the introduction of real-time pricing.

A durable TPM – why some historic investments are proposed to be included

The Authority recognises its proposal to recover the depreciated costs of 'historical investments' – major investments in recent decades that are still being paid for – through the benefit-based charge has been contentious. This is not a retrospective charge, but the reallocation of the remaining depreciated costs to those who are benefitting from each grid investment.

The Authority's key reason for applying benefit -based charges to some historical investments is to make a new TPM durable.[7] This is important if the efficiency benefits are to be achieved, and to stop ongoing uncertainty about the TPM. Uncertainty is not conducive to making long-term investment decisions.

Consumers need to be able to accept the pricing methodology and pricing outcomes. In the Authority's view, pricing arrangements are more durable when you 'pay for what you get'. The pricing arrangements for connection charges have not been contentious because they are based on that principle: customers pay for the connection assets that they use and do not pay for other customers' connections.

The Authority considers that durability would be undermined if consumers in some regions would have to pay both for new investments made for their benefit and continue to pay for major investments they didn't benefit from.[8]

For example, with a benefit-based charge Christchurch consumers could expect to pay most of the $283 million cost of the planned new switching station and new transmission line into Islington. If the seven major grid investments were to be grandparented, the same consumers would also continue to pay nine percent of the cost of investments that benefitted mainly North Island consumers, such as the $876 million North Island Grid Upgrade.

[7] More generally the Authority as a matter of principle does not 'grandparent' regulatory settings, as that would tend to provide preferential treatment to incumbents and can reward inefficient actions.

[8] To illustrate, 77% of the benefits that the seven major investments generate accrue to upper North Island customers, but those customers currently pay only 35% of their costs.

A more specific reason for including historic assets is HVDC-specific. The Authority considers there is no rationale for continuing to put what is essentially an extra tax on South Island generation. It inefficiently discourages investment in South Island generation, and is inconsistent with tackling the broader challenge of materially increasing New Zealand's renewable generation portfolio to support the transition to a low carbon economy.

Compromise on historic investments might seem expedient, but would undermine the durability of the TPM. The Authority is conscious of the example set by the review that produced the current TPM, which was implemented in 2008. That review produced a TPM which, in the Authority's view, has fundamental flaws – including that it failed to address the issue of historical investment costs – and as a result it did not prove to be durable. In fact, a new review of transmission pricing began almost immediately[9], leading to 10 years of uncertainty for the industry. Taking a lesson from that experience, we consider that it is important to address this issue head on with stakeholders.

In terms of quantifiable efficiency benefits, we have found little difference between including and excluding these historic investments from the benefit-based charge. The Authority has not been able to quantify the costs of a less durable proposal (that is, one that excludes the seven historic investments), and does not think that it can be done robustly, although the Authority considers these costs could be considerable.

The Authority also notes a number of contextual points, in that the Authority:

- has not always proposed to apply benefit-based charges to historical investments. Previous proposals for the TPM guidelines considered a range of approaches. Submissions, such as Professor Littlechild's 2016 report, gave reasons why including historical investments would promote efficiency.[10]
- sought advice on this issue from Professor Hogan, who is a well-known expert and had been involved with the New Zealand electricity market from prior to its establishment. He said that there was nothing that he was aware of that was inefficient or inappropriate in applying benefit-based charging to existing assets, provided no incentives for inefficient entry or exit are created. He also noted that such incentives can be avoided by using the tools we have considered in our 2016 proposal and that are presented in this proposal.[11]
- considers its proposal is consistent with its approach to distribution pricing in this regard. The distribution pricing principles do not promote – and, to the Authority's knowledge, distributors are not contemplating – reform of their pricing structure that would apply only to future investment in the distribution network. Such a limited approach would not succeed in addressing the urgent problems that distributors are facing in terms of distributed energy options and other new technologies. Neither would a limited approach with grandparenting succeed in the transmission space.

9 The Authority's predecessor, the Electricity Commission initiated a further review of the TPM in April 2009. It established a Transmission Pricing Technical Group (TPTG) to provide advice and assistance on the TPM review. Around the same time, the New Zealand Electricity Industry Steering Group, which was established by the CEOs Forum, undertook a review of transmission pricing.

10 Littlechild, S, *Report on the Electricity Authority's Transmission Pricing Methodology Review,* 26 July 2016.

11 See Filenote: *Teleconference with Professor William (Bill) Hogan of Harvard University*, 17 May 2018

The proposal would be for the long-term benefit of consumers

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.

This is supported by the cost-benefit analysis (CBA), which has quantified the proposal's net benefits to consumers. The quantified costs and benefits are set out in Table 5, Chapter 4.

Consumers would benefit, for example, if the proposal were to lower the cost of using electricity, or if they didn't have to take actions to avoid overly high peak charges – whether that be by turning off heating on cold winter nights or by investing in alternatives to grid supplied electricity, for example, installing solar panels and batteries. A CBA captures such net benefits in dollars.

A CBA is not a precise exercise, but it does give a sense of the order of magnitude of benefits and costs that are involved. While for ease of presentation and comparison the Authority presents a point estimate as its central scenario, this estimate should be viewed as a reasonable but not definitive point within a wider range of estimates.

The CBA describes qualitatively a number of important impacts that have not been able to be quantified. The lack of quantified dollar amounts does not make such impacts any less relevant. Specific examples of probably the most important unquantified impacts are:

- the benefits from removing the incentive for mass-market consumers to invest in technologies that help them avoid transmission charges
- the costs of a less durable proposal (that is, one that excludes the seven historic investments) which the Authority considers could be considerable.

In addition, a CBA is only a tool to support deliberation and decision-making, with the insights it provides to be considered along with a much broader range of factors.

The CBA shows that a TPM consistent with the proposed guidelines would likely deliver significant benefits to consumers between implementation and 2050. The key quantified results are, in approximate terms:

(a) a net benefit of $2.7 billion for our proposal over the status quo for the central scenario within a broader estimated range of $0.2 billion to $6.4 billion, where:

   (i) $2.36 billion would come from reducing electricity cost and increasing its use at peak times when consumers value it most highly. This is after netting out costs such as for implementation and grid investment brought forward

   (ii) $200 million would come from more efficient (that is, avoided) investment in technologies such as grid-scale batteries that would otherwise be used mainly to avoid transmission charges

   (iii) $145 million would come from more efficient investment in transmission and generation and consumer decisions about connection, electrification and location, as a result of allocating grid costs to those who benefit

(b) a net benefit of $858 million compared to the alternative option that we modelled, which replaces existing charges with a broad-based usage charge.

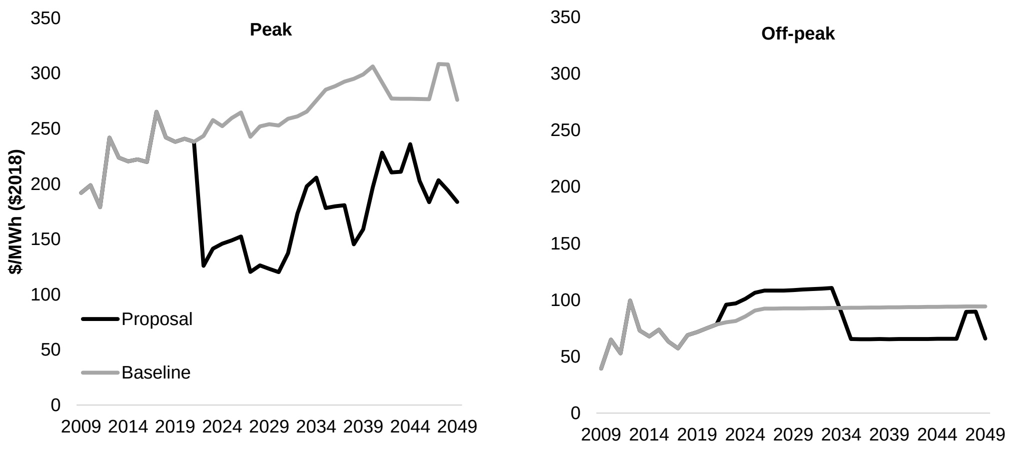
The range represents, at the low end of the spectrum, a scenario with the most cautious of assumptions and at the high end of the spectrum the most optimistic but still realistic of assumptions. Presenting a range is good practice. It gives readers a sense of the effect of uncertainties and unknowns to which professional judgement has had to be applied.

The main benefits to consumers come from improving transmission price signals, which will encourage more efficient grid use. These types of benefits had been assumed to be minor in previous modelling, but we consider that these consumer benefits are in fact significant.

This is because the current RCPD charge creates a very strong price signal that inefficiently discourages consumers to reduce electricity use at peak times, even though the grid has capacity for this demand, and encourages them to unnecessarily invest in technologies like solar panels and, in future, increasingly in batteries. The signals will get stronger as distribution pricing becomes more cost-reflective.

As shown in Figure 1, the proposal would cause a fall in peak prices by an annual average of 38% out to 2049, compared to the status quo, avoiding the RCPD cost-spiral. Off-peak prices would rise initially by an average 19%, compared to the status quo, but then fall roughly 40%. This is because of increased investment in generation to meet higher peak demand, and reduced use of network-scale batteries under the proposal, which reduces off-peak demand, compared to the status quo.

Figure 1: Effective electricity prices (wholesale prices plus interconnection charges)



The proposal provides protection against high price rises

The proposal would involve a rebalancing of transmission charges between customers.

Some consumers and businesses would pay lower charges initially, and some would pay higher charges than they would under the current TPM. This is the consequence of the proposed:

- allocation of depreciated cost of seven major (historical) grid investments based on benefit
- distribution of other costs across all load customers through a residual charge.

For those customers who would face higher transmission charges, increases are mostly modest. For example, in networks where charges rise, the increases would average $21 for the year on an average residential consumer bill.[12] Increases would be significantly higher for some

[12] The average household bill is $2,100 per year; consumers can save an average $200 per year by switching retailer.

major industrial customers that have responded to current incentives and made operational investments that mean they currently pay very low or no interconnection charges.

To reassure consumers that they will not experience an electricity bill shock, the proposal provides for a 3.5% cap on increases in the total electricity bill as a result of a new TPM consistent with the proposed guidelines. A cap, recommended by submissions to the 2016 issues paper, would give households and businesses certainty on the level of charges in advance and allow industrial customers time to adjust to the new charges.

The cap would mean that, in areas where transmission charges rise, average electricity bills would not need to rise by more than 3.5% as a result of the proposal. For directly-connected large industrials the cap would rise after five years by two percentage points per year.

The Authority's modelling indicates the price cap would support three distribution networks and, in particular, four directly-connected industrial consumers. This proposed support of $15.4 million in year one would be funded by all transmission customers in proportion to their total benefit-based and residual charges. Price cap support would fall to zero over time.

Some of the changes since the previous TPM proposals

The proposal set out in this 2019 issues paper builds on the Authority's past TPM proposals, but has also changed, having been informed by the submissions on the second issues paper and supplementary consultation paper. For example, this paper includes proposals to:

- allow Transpower greater discretion in designing the TPM to balance competing objectives such as precision vs robustness, simplicity, certainty and implementation costs
- raise the threshold for high-value investments from $5 million to $20 million as proposed for example by Transpower, PwC and Castalia, to reduce the administrative burden on Transpower and to align with the Commerce Commission's approach
- reduce the number of current assets that would be subject to the benefit-based charge to seven major investments, where the Authority has estimated clear benefits to consumers
- set the benefit-based charge for those seven investments according to an allocation determined by the Authority, in response to Transpower's view that this would reduce the administrative burden. The Authority considers this would enable earlier implementation, ensuring the gains associated with the new TPM are achieved earlier
- make the peak transmission charge a transitional and non-mandatory arrangement, and that its design is not restricted to a Long Run Marginal Cost form
- allow Transpower to use proxies for the net benefits of grid investment when determining benefit-based charges, to reduce administrative burden, as various submissions suggested that producing precise estimates would be too difficult.