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1 October 2019

Submissions
Electricity Authority
P O Box 10041
Wellington 6143

By email: submissions@ea.govt.nz

Dear Jean-Pierre,

Re: Consultation Paper-Transmission Pricing Methodology

Pioneer owns and operates distributed generation that supplies 200GWh per annum to local load. We are also a partner in Southern Generation Limited Partnership whose distributed generation capacity injects over 200GWh per annum into local networks, with another 30GWh under construction.

In addition to our concerns about the impact of the TPM proposal on distributed generation, this submission also highlights our concerns about the impact of the proposal on independent retailers without generation. Pioneer is a shareholder in Pulse Energy and Ecotricity.

Pioneer supports the submission by the Independent Electricity Generators Association Incorporated and Southern Generation Partnership Limited.

Recommend a transition to any new TPM

Pioneer agrees there is a case for changing aspects of the allocation of transmission charges. For example, we agree that parties in addition to South Island generators benefit from the HVDC and that the rate charged for using the grid during peak time is too high.

However, we do not support a drop dead changeover to a completely new methodology on a particular date nor the stated urgency supporting what could be described as an economic experiment.

Instead, Pioneer submits there must be a transition to any change, for the following reasons:

- There is currently around 1,200MW of electricity demand that is not currently carried by the transmission grid, but supplied by local embedded generation. Further, Transpower's analysis for ACOT implementation identified that 80% of existing distributed generation is necessary for Transpower to achieve its grid reliability standards – this plant contributed 628MW during winter peaks. Further, all distributed generation in the Upper North Island region is required for Transpower to achieve its grid reliability standards – that is a 177MW contribution to winter load. This distributed generation is effectively equivalent to transmission in delivering a reliable supply of electricity. If the distributed generation did not exist the transmission infrastructure would be bigger. Any change to the output of this embedded generation as a result of the proposed TPM will cause security of supply issues.

- It is uncertain how peak demand volumes will change with the removal of the current peak demand RCPD charge. Constraints in both the transmission and distribution network could suddenly occur.

  The quickest way to manage increases in peak demand in the short term is to construct thermal peaking plant close to load. It is proven consenting of these plant takes less time that renewable generation plant and thermal peaking plant is economic with the likely higher peak spot prices. This outcome is completely inconsistent with the government's climate change objectives and international commitments. It is also inconsistent with the government's 100% renewables target.

- The Authority agrees that the new methodology is expected to result in more nodal price volatility. Transmission constraints mean generators will more often be pivotal. The wholesale hedge market must be more liquid and reliable than currently before a change to transmission cost recovery is implemented.

- If the residual charge is to be 'tax-like' it is inconsistent with natural justice to tax participants on the basis of behaviour incentivised by the previous methodology. Participants must know what rules the tax is based on before incurring any tax. The current proposal locks in behaviour the Authority disagrees with (that is, suppresses demand during periods when 'consumers value electricity the most'). If the Authority wants people to consume as much as they want at peak times why shouldn't the new charge be based on this desirable behaviour?

- The radical nature of the proposal, with a drop-dead implementation date, is inconsistent with the Authority's Consultation Charter. Pioneer is sceptical about the value ascribed to this proposal in the Authority's CBA[1] and therefore considers that Principle 4 – Preference for Small-Scale 'Trial and Error' Options[2] applies. This Principle states that:

  "*the Authority … will give preference to options that are initially small-scale, and flexible, scalable and relatively easily reversible with relatively low value transfers associated with doing so. In these circumstances the Authority will monitor the effects of the implemented option and reject, refine or expand the solution in accordance with the results from monitoring.*"

[1] Pioneer's opinion relies on other submitters' reviews of the CBA.

[2] https://www.ea.govt.nz/dmsdocument/14242-consultation-charter-december-2012 page 5

- The Electricity Price Review Panel in its Options Paper[3] appeared to endorse Transpower's submission that "*any change [to the TPM] was simple to understand and implement, and was incremental* …"

- There is no urgency, as the Authority has claimed. This is confirmed by the Authority's CBA when any reasonable positive benefits do not eventuate until 2031.[4]

- there are options to achieve changes to the allocation of transmission costs that are less risky or experimental – for example, increasing the number of periods used for the interconnection charge and reallocating the HVDC charge to a wider group of beneficiaries.

Recommend adjustments to the proposed TPM

Pioneer's recommends the following changes to the current TPM:

1. Reduce the strong signal from the RCPD charge over time – say 5 years – by increasing the number of trading periods included in the peak time period from 100 currently to the Authority's assessment of the number of peak periods in five years.

   The advantages of this approach are:
   a. more information will be available about how consumers change their behaviour with a weakening peak demand price signal. We note Transpower's analysis that a 30MW change in peak demand in the Upper South Island brings forward a $44.2m investment by 2 years
   b. during this RCPD phase out period Transpower can develop and implement a permanent peak charge that is in line with the Authority's statutory objective.

2. Introduce a permanent peak charge – available for any constrained points in the network at a rate that varies depending on the signal it is attempting to send. This signal should be contractable through Grid Support contracts.

   The Authority's reliance of wholesale nodal prices to influence investment is misguided. Nodal energy prices reflect the short run cost of using the grid and to date have not proven sufficiently strong to incentivise new generation investment. The issues we perceive with nodal price signals are:
   a. decisions about the timing of new generation build are made by the same party that can experience the advantage of transmission constraints (a pivotal position) and generally higher spot prices (for example, the increasing tight supply situation over the last few years and new utility scale generation capacity not coming on-stream until late 2020)
   b. a high nodal price due to constraints disappears immediately after an increase in generation or transmission capacity – this impacts / delays the timing of a new generation investment

[3] https://www.mbie.govt.nz/assets/42ac93a510/electricity-price-review-options-paper.pdf page 23
[4] https://www.ea.govt.nz/dmsdocument/25604-tpm-technical-workshop-presentation page 28

   c. the nodal price is too volatile to support investment that defers transmission investment
   d. nodal price volatility is going to increase making the required return on any new investment higher to compensate for this risk
   e. on an inter-day basis nodal price variability is more closely linked to renewable fuel availability than peak demand or transmission constraints.

3. Transition the HVDC charge over 3 years to the Residual charge or 50 / 50 generation and load at a net $/MWh basis (which is the same basis as the EA's detailed estimation of benefits/beneficiaries).

   The basis of the HVDC charge is already transitioning to volume rather than maximum injection. Transpower and the Authority agreed that a MWh injection allocator was more efficient than a peak demand allocator.

4. If the Authority persists with a Benefit-based charge we recommend developing a regionally based assessment of benefits for recovery of new transmission investments. Pioneer is concerned that the proposed detailed individual net private benefit analysis:
   a. is a different to the regulatory test to that used to approve transmission investment
   b. will always be subjective and therefore not necessarily durable
   c. will incentivise parties to argue against any transmission investment even if it is required for grid reliability or is economically efficient
   d. will incentivise parties to argue against any transmission investment even if they are a beneficiary to avoid paying for the investment
   e. results in unnecessary delays in planning, consenting and constructing transmission infrastructure
   f. is to be calculated by Transpower prior to the actual transmission investment
   g. is sensitive to subsequent changes in load or new generation that do not meet the Authority's proposed thresholds for re-opening
   h. is not flexible to moderate changes from innovation, changing demand etc.

   Pioneer notes that the research trip to the US[5] revealed zonal or regional benefits were estimated for only new transmission investments and allocation can be on a share of that regional's coincident peak demand.

5. The Residual charge will recover the balance. We support the proposed guidelines which give Transpower the flexibility to determine the most efficient allocator for this charge.

   As discussed above, it is imperative that the methodology for this charge is known before any 'lock down' of the basis of allocation. Natural justice means that

[5] https://www.ea.govt.nz/dmsdocument/25122-beneficiaries-pay-in-usa-joint-report

participants need the opportunity to change their behaviour for this new charge to make the imposition of the charge most impactful.

Pioneer recommends the allocator take into account the benefits of distributed generation to the electricity system. Under the current Gross AMD proposal networks with distributed generation are paying for two transmission services – that provided by Transpower and that provided by the distributed generation on their network delivering electricity to their customers.

Recommend a revised process timeline

Pioneer disagrees with the Authority "*that multiple full consultation rounds … would be unnecessary given the Authority would have just consulted extensively on the proposed guidelines* … ." Pioneer agrees with the level of discretion in the draft guidelines and suggests informal and insufficient consultation opens Transpower up to the risk of legal action.

Further, there is no information about how Transpower, with a regulated total allowable revenue cap, will fund implementation of the Authority's guidelines.

Residual charge proposed to be allocated on Gross AMD

Under the Authority's TPM proposal to allocate the Residual charge on the basis of Gross AMD, Pioneer asked the following question:

> "Can the EA please confirm that the transmission charge associated with adding distributed generation on to load under the gross AMD calculation is intended to be passed on by distribution companies to load on the network and not to DG? "

The Authority has clarified that a "*distributor with distributed generation pays the same residual charge as an otherwise identical distributor without distributed generation*".

However, relative to the current allocation of transmission charges the distributor with distributed generation is going to pay a higher proportion of the total transmission charges. Using a Gross AMD allocation, results in an increase in the allocation of the Residual charge for networks with distributed generation relative to the status quo. For example, Buller, Westland and Horizon networks all incur a large increase in transmission charges because of the different treatment of distributed generation.

Pioneer, along with other owners of distributed generation, are concerned that distribution companies may pass on any resulting increase in transmission charges to distributed generation.

Pioneer submits that the answer provided by the Authority provides no assurance to distributed generation.

In addition, the Gross AMD approach deliberately protects the transmission grid from any competition from alternatives by creating an environment that disadvantages transmission alternatives.

At the same time as proposing an approach that assigns no value to distributed generation which competes with transmission to deliver electricity, the Authority is leaving open the possibility that distributed generation will face costs that other generators do not face!

Pioneer disagrees with the Authority's proposal to allocate the Benefit-based charge on the basis of 'net' and the larger Residual charge on the basis of 'gross'. The Authority argues that the reason for a 'net' allocator for benefit-based charge is "it better reflects the benefits customers receive from the grid". Why are the benefits from the grid any different when allocating the remainder of transmission costs?

Proposed TPM inconsistent with Authority's cost reflective distribution pricing approach

The Authority's Distribution Pricing Practice Note acknowledges that peak demand drives capacity costs and rates Time-of-use tariff structure as a "crude but actionable signal" which "may require re-tuning as usage patterns adapt or economic costs change".[6] This pricing approach to manage / influence the level of peak demand on distribution networks is inconsistent with the Authority's proposal to fix the measure of peak demand at a historic point in time for the Residual charge as well as make the allocation of the Benefit-based charge fixed at a point in time prior to the transmission investment.

Importance of a liquid and efficient hedge market

The Authority acknowledges the wholesale nodal spot price will be more volatile as a result of this TPM proposal. Volatility increases risk. The Authority has the responsibility to ensure an effective and efficient mechanism to manage this risk is available before imposing rule changes that it knows will increase risk.

A number of aspects of this TPM proposal potentially increase the dominance of gentailers – in determining the level of the spot price and the timing of investment in new utility scale generation capacity. If the Authority is going to be successful in its focus "*on improving the arrangements in the electricity industry to promote competition*"[7] improved liquidity in the spot and hedge market is essential before implementing the TPM proposal.

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[6] https://www.ea.govt.nz/dmsdocument/25528-distribution-pricing-practice-note-august-2019 page 13

[7] https://www.ea.govt.nz/dmsdocument/9494-interpretation-of-the-authoritys-statutory-objective-february-2011 paragraph A.28

Impact of increase in peak demand on transmission and distribution losses

Pioneer notes the CBA analysis of the impact of the proposal on ‘transport costs’ ie, losses and constraints using vSPD.

Pioneer queries if the Authority has undertaken any sensitivity analysis to assess the risk of a sudden, unmodelled change in peak demand – noting that 800MW of demand is currently managed by distribution companies at peak use time.

This is important as demand has an exponential effect on losses (losses = current^2 x system resistance). The impact of any MW of load not offset by load control or distributed generation will have an exponential impact on the losses on the system.

We would welcome the opportunity to discuss this submission with you.

Yours truly

Fraser Jonker

Chief Executive