IEGA

INDEPENDENT ELECTRICITY GENERATORS ASSOCIATION

Chairman: Warren McNabb,
warren.mcnabb@altimarloch.com
Secretary: David Inch, david@nzenergy.co.nz

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Submissions
Electricity Authority
P O Box 10041
Wellington 6143

By email: tpm@ea.govt.nz

Dear TPM team,

RE: Consultation Paper – Transmission pricing methodology: 2019 Issues paper: supplementary consultation

The Independent Electricity Generators Association Incorporated (IEGA) appreciates the opportunity to make this submission on the Electricity Authority's (Authority) supplementary consultation on changes to the 2019 transmission pricing methodology (TPM) proposals. [1]

Linkage between proposed TPM and the Authority's revised strategy

The IEGA queries how decisions on such a significant and controversial topic as the proposed TPM can be progressed when the Authority is reviewing its strategy. This strategy review also includes an intention to review the Authority's interpretation of the statutory objective.[2] The IEGA submits decisions on the proposed transmission methodology while the interpretation of the statutory objective is anticipated is inconsistent with best regulatory practice.

One of the draft emerging outcome themes of the revised strategy is "Zero-carbon Aotearoa":[3]

> **1. Zero-carbon Aotearoa**
> This theme recognises the importance of decarbonisation, electrification of the economy, and creating a platform to export and realise the benefits of New Zealand's renewables advantage. In addition to ensuring the electricity system is reliable, resilient and adaptive over the long term, we have a core role in enabling a just transition to decarbonisation while maintaining energy security and inward investment across the sector.

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[1] The Committee has signed off this submission on behalf of members.

[2] Page 11 https://www.ea.govt.nz/dmsdocument/26339-strategy-development-2020-emerging-themes-discussion-paper

[3] Ibid Page 15

One of the IEGA's key concerns about the 2019 TPM proposals, expressed in our October 2019 submission[4], was that the proposed structure to recover transmission costs was highly inconsistent with wider government climate change and energy policy objectives.

The proposals in the supplementary consultation perpetuate this inconsistency. In particular, the proposed the ten-year lagged update of the residual charge allocation and adjusting the benefit-based charges when a plant closes.

Growth in demand for electricity is going to be more dynamic as New Zealand decarbonises and transitions to a low emissions economy. For example, the government's provisional emissions budget for the period 2021-2025 assumes the following actions have been taken by the year 2025[5]:

Sector	Change by 2025	Emissions abatement per year in 2025 (kt CO_2-e)
Transport	One third of the projected impact by 2030 of the currently proposed transport package has been achieved through a combination of greater electric vehicle uptake, higher efficiency internal combustion engines, and mode shift	500
Space and water heating	One sixth of space and water heating in commercial and residential buildings that currently uses coal, LPG or gas switched to biomass or electricity	300
Process heat for food processing	Half of the identified energy efficiency opportunities that are of net benefit are adopted	450
	25 per cent of process heat that currently uses coal or gas has switched to biofuels or electricity	700
Electricity	One-third of the electricity efficiency potential identified by EECA is implemented	450
	Additional wind and geothermal renewable stations are built to displace the remaining baseload gas-fired power station by mid-2024[8]	1,100

We also query if the very lengthy timeframe for this review of the TPM and the quantum of feedback provided by industry participants is consistent with 'trust and confidence' as an outcome theme for success in the electricity sector.

The complexity of the proposed TPM and step-change in charges for some customers (despite the proposed cap) create uncertainty and confusion when major investment in the electricity system will be required. The IEGA suggest the proposals in the supplementary consultation continue to be inconsistent with the government's overall objectives and with one of the key outcome themes that the Authority will be measuring its success against namely Zero-carbon Aotearoa.

The remainder of this submission is feedback on the four proposed changes.

[4] Page 6-7 https://www.ea.govt.nz/dmsdocument/25716-independent-electricity-generators-association-incorporated-tpm-submission-2019

[5] See page 28 https://www.mfe.govt.nz/sites/default/files/media/Climate%20Change/reforming-the-ets-proposed-settings-consultation.pdf

1. Recovery profile for future benefit-based investments

Application of depreciated historic cost to both pre-2019 and post-2019 investments is pragmatic. Using the same depreciation methodology for determining whether an investment proceeds (ie, when gaining Commerce Commission approval) and recovery of those costs from transmission customers makes sense. It may also make assessment of non-transmission solutions during the investment development process easier and more relevant.

2. Adjusting benefit-based charges when a plant closes

The proposal relates to a business that continues to be a transmission customer after they have decided to close a plant. It is unclear how many transmission customers, other than generators, would be in this position.

This is probably relevant for thermal generation plant. Planning for a transmission grid investment may or may not have taken into account the likelihood of an existing thermal plant closing. As indicated in the consultation paper, this approach may place an incentive on the thermal plant owner to be more transparent about any timing of a change in operation of that plant.

Without rereading the 2019 proposals, rules about allocating the benefit-based charge create varying incentives no matter how they are structured.

- Closure of a thermal plant may reduce overall capacity utilisation of the nearby transmission grid as well as use of the recently commissioned new grid assets but the thermal plant owner will continue to pay for the new transmission assets for 10 years – potentially making it more economic to continue operating a thermal plant to recover these costs.
- If the same transmission customer opens a new plant in the same area of the grid / subject to the same benefit-based charge within 10 years - does this new plant also get allocated benefit-based charges? Maybe not because the allocation has already been determined, and therefore the transmission customer is indifferent. If the benefit-based charge is reallocated to the new generating plant then that transmission customer pays benefit-based charges for both plants (and other users pay less).
- Reduced transmission capacity utilisation may encourage another generator to construct a plant in that area – will this new generator be charged the benefit-based charge?

However, the IEGA's key concern is that the proposal treats grid connected generation plant differently from embedded generating plant. A network company is never going to be a 'plant that closes' but could experience substantial changes in the load on its network. For example, the network company will not experience any reduction in transmission benefit-based charges if a substantial industrial load closes because of the proposed methodology to allocate benefit-based charges to network companies on Gross AMD allocator.

3. Regular updates of the residual charge allocation

The IEGA continues to disagree with the proposed Gross AMD allocation approach for the residual charge. The consultation paper shortens this to 'AMD' which is misleading.

It appears Gross AMD is used only once in the determination of the allocation of the residual charge – to set the initial allocation (based on the average Gross AMD over the period 2014-18).

The proposal is to adjust this Gross AMD allocation by the annual percentage change in actual consumption (MWh). From the IEGA's perspective it is difficult to justify changing from one methodology (static one peak demand period) to another (dynamic total consumption). If the Authority now favours MWhs as the ongoing allocation of residual changes why is this not the right answer for the initial allocation?

We also disagree with the 10-year lag being proposed. In our view, this is not consistent with the significant increase in electricity demand anticipated as industrial load and transportation electrifies.

The Authority is designing the allocation of the residual charge based on a proxy for ability to pay[6]. However, if a 20MW industrial load changes from burning coal to using electricity and the change in the allocation of the residual charge is lagged by 10 years this is hardly consistent with ability to pay.

We suggest this lag also makes estimating future transmission charges more uncertain and difficult to forecast. This could seriously impact businesses choices about switching to renewable fuel.

Below we repeat our October 2019 submission in relation to using Gross AMD. The proposal to adjust the initial Gross MAD allocation with a percentage change in MWhs consumption does not address any of our concerns.

> ***Use of Gross AMD as an allocator of a significant portion of transmission costs***
>
> *The Authority proposes to fix allocation of both the Residual and Benefit-based charges on historic measures of demand and net private benefits respectively.*
>
> *The issues we have with these historic allocations is that:*

- *it locks in behaviour that the Authority is trying to discourage – namely people consuming less when they value electricity the most*
- *The Authority's consultation paper states "A key assumption is that mass-market load will respond to both transmission and wholesale price signals over the period to 2049."[7] There is no point in responding to transmission price signals if transmission costs are allocated to network companies on the basis of historic Gross AMD*
- *it does not support cost reflective network management of peaks*
- *network companies are penalised for investment in distributed generation on their networks which can provide substantial benefits to them in the management of their network and to their local consumers (for example, distributed generation supplies ~50% of the load on the West Coast)*
- *under Gross AMD no alternatives can compete with transmission to deliver electricity to consumers – that is network companies are disinterested in distributed generation on their networks supplying their customers close to load*
- *stymies innovation as there is no financial benefit from investment that alters consumption patterns or the source of electricity*
- *it is potentially inflexible to moderate changes in consumption or generation patterns.*

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6 Paragraph 5.2 https://www.ea.govt.nz/dmsdocument/26354-supplementary-consultation-paper-transmission-pricing-methodology-2019-issues-paper

7 Consultation paper paragraph 4.43 page 28 - 29

The IEGA recommends the use of average or median demand for allocating the balance of Transpower's revenue to load, including industrials. Network companies and industrials must be able to net off average or median output of distributed generation to work out the allocation. As New Zealand focuses on electrification of industrial processes and transport, average or median consumption will be more flexible or reflective of consumption over time.

This is more reflective of ongoing use of the grid (especially as the incidence of Gross AMD is highly dispersed intra-day) and allows some benefit from investment in commercial scale distributed generation and co-generation. The impact on industrials with distributed generation highlights our concern. The use of an arbitrary price cap only serves to mask the underlying material impacts on businesses facing cost uncertainties in the face of climate change policy."

4. Prudent discount for charges above standalone cost

The Authority "*now propose that the guidelines also allow a customer to apply for a prudent discount that would reduce its transmission charges to the efficient standalone cost of supplying it with the transmission services it receives*". The economic theory of the proposed approach is sound – that charges should not exceed standalone costs.

This prudent discount proposal implies that the proposed benefit-based charge and residual charge could result in a transmission customer being charged more that their standalone costs. The transmission pricing methodologies that have been in place since day one has resulted in only two Prudent Discount Agreements and one Notional Embedding Agreement with Transpower.[8]

Now with the proposed TPM methodology the Authority appears to be expecting a number of parties will be able to claim that the combination of their benefit-based charge and residual charge will be above the standalone cost of a transmission service.

This prudent discount approach looks like a patch over a problem instead of addressing the underlying symptoms – that is, the benefit-based and residual charge methodologies are at fault by creating transmission charges for specific customers above standalone cost. The 'benefit' of an investment (and therefore the charge) bears no relationship to the cost of that investment.

We have the following concerns about how this approach would be implemented:

- Will Transpower have discretion to accept applications for a prudent discount?
- If Transpower receives multiple applications for prudent discounts at the same time how will it prioritise these applications?
- Adjusting one transmission customer's charge to take into account a prudent discount will result in other customers being charged more. This may result in another transmission customer proving the revised charge is above their standalone costs and successful applying for a prudent discount – which impacts the next transmission customer in the same way etc
- Is Transpower funded and resourced for this approach?
- Can Transpower's decisions be legally challenged and what happens to payment of transmission costs in the meantime?

[8] A Notional Embedding Agreement was the type of agreement that preceded PDAs https://www.transpower.co.nz/industry/revenue-and-pricing/pricing

Concluding comments

In light of the Authority's review of its strategy, outcome themes, and proposed review of the interpretation of its statutory objective, the IEGA reiterates our views on how components of the current TPM can be adjusted to achieve an allocation of transmission costs that instils trust and confidence and contributes to New Zealand achieving Zero-carbon Aotearoa:

- amend the current measure of regional coincident peak demand to reduce the strength of the peak time price signal;
- introduce a permanent peak price signal that is more flexible – could be location specific with a variable price as constraints become more prevalent;
- reallocate the historic and future HVDC costs to the wider group of parties that benefit from this asset; and
- if there is a need for a new charge that recovers the balance of Transpower's allowable revenue that is based on the average or median demand so that network companies and industrials have some benefit from local generation.

We acknowledge that the current RCPD signal is too strong (reflecting recent transmission investment and the limited number of trading periods used to measure peak demand) and agree that the HVDC provides benefits to other parties as well as South Island generators.

However, the proposals in the supplementary consultation have not persuaded the IEGA to change its view – we do not support the Authority's TPM proposal as it creates significant uncertainty at a time when certainty is required.

It seems odd that considerable effort has been made to investigate the proposed changes but the benefit of each change can not be quantified or is assumed to have minimal impact on the cost benefit analysis. The IEGA queries if the Authority will do a cost benefit analysis of the final proposed TPM taking into account all the changes from the 2019 proposal and cost benefit?

In addition, the IEGA submit that any change to the TPM must be implemented in an incremental manner so that the intended and unintended consequences can be assessed and the approach tweaked to ensure reliable electricity supply and strong competition in electricity generation and retailing. Our view is consistent with that of the Electricity Price Review Panel in its Options Paper[9] when it appeared to endorse Transpower's submission that "*any change [to the TPM] was simple to understand and implement, and was incremental* …".

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

Yours sincerely

Warren McNabb
Chair

[9] https://www.mbie.govt.nz/assets/42ac93a510/electricity-price-review-options-paper.pdf page 23