1 October 2019

Jean-Pierre De Raad
Manager, Network Pricing
Electricity Authority
By email to submissions@ea.govt.nz

Dear Jean-Pierre

Consultation Paper – Transmission pricing review

1. This is a submission by the Major Electricity Users' Group (MEUG) on the Electricity Authority consultation paper "Transmission pricing review, 2019 issues paper" dated 23rd July 2019 (the "2019 proposal") along with other relevant consultation materials.[1]
2. This submission is not confidential. Some members may make separate submissions.
3. Attached and to be read as part of this submission is a report by Mike Hensen of NZIER "TPM 2019 Cost benefit analysis, Initial review" dated 1 October 2019.
4. MEUG has answered selected questions and focussed on a few of the topics in the consultation paper. MEUG's silence on other questions and topics should not be read as agreeing with that aspect of the proposal.
5. The appendix has a glossary of terms used. References to paragraphs in the consultation paper and other documents are enclosed in square brackets.
6. Four topics are covered in this submission in the sections that follow titled:
    a) The cost-benefit analysis (CBA).
    b) Options to reduce the distortionary and instability effects of the residual.
    c) Benefit-based charges.
    d) Cap on transmission charges.

[1] Consultation paper, refer https://www.ea.govt.nz/dmsdocument/25466-consultation-paper-transmission-pricing-methodology2019-issues-paper-full-document.

7. An important feature of the 2019 proposal compared to the 2016 proposal has been reduced prescription in the Transmission Pricing Methodology (TPM) guidelines and more flexibility given to Transpower to revise the TPM.[2] MEUG acknowledges this positive step which was requested by MEUG and other submitters on the 2016 proposal.[3]

The cost benefit analysis

8. MEUG has asked NZIER for advice on whether the CBA is robust. The CBA is complex and MEUG would like to acknowledge the good engagement we have had with Authority staff and advisors to assist in clarifying aspects of the CBA. Not surprisingly for a policy issue as complex as TPM we have found further aspects we would like to consider. The advice MEUG has sought from NZIER for this submission is therefore a stocktake of current aspects of the CBA to consider. We expect submissions from other parties will provide analytical evidence to give another lens for us and other parties to consider the CBA.

9. The intention of MEUG is to make a cross-submission by the 31st October due date with a view at that date on whether we think the CBA is robust considering advice from NZIER and other submitters.

Options to reduce the distortionary and instability effects of the residual

10. The residual is distortionary and undermines stability of future TPM because some costs recovered confer no benefit to those that are deemed to have to pay. We cover this first topic in the next sub-section headed "unallocated residual charges."

11. The second topic is whether there is a better denominator than historical anytime maximum demand (AMD).

12. An important outcome for MEUG when considering the residual is that costs associated with assets that do not have a beneficiary should not be charged to consumers, and that any costs associated with such assets should not be included in the residual charge. Achieving this is not trivial and requires other decision-makers along with the authority to consider their role and accountability in terms of the long-term benefit to consumers. We suggest such a solution later in [18]. On the second topic of the choice of denominator we propose a new transmission pricing principle [20 a)] "Any additional costs, where the cost of estimating benefits is not prohibitive, that confer no benefit on any user should be a cost to the transmission service provider."

---

[2] In particular clause 2 of the draft TPM guidelines (appendix A of the consultation paper) states "Transpower may propose a TPM which differs in its details from the particular requirements in the Guidelines, if it considers, in its reasonable opinion, that doing so would better meet the Authority's statutory objective than complying with the Guidelines in their entirety."

[3] For example, MEUG submission 26th July 2019 [15] "The proposed guidelines should set out the outcomes the EA expects any TPM to achieve. The proposed guidelines are overly prescriptive and should not constrain Transpower's ability to design a TPM that achieves the outcomes the EA wants to see."
Refer https://www.ea.govt.nz/dmsdocument/21014-major-electricity-users-group.

Unallocated residual charges[4]

13. The size and potential scale of the problem are set out below:

    a) The residual charge is 58% of forecast transmission charges in 2022.[5] This is 2.7 times more than the next largest benefit-based charges (22%). Connection charges comprise the balance of charges (20%).

    b) Residual charges for 2022 total approximately $500m.[6] In round terms MEUG estimates:[7]

       - $200m pa for unallocated costs including overhead expenses; and
       - $300m pa for capital charges for pre-2019 interconnection assets not recovered using the benefit-based charge. We call these "unallocated residual capital charges."

       Unallocated residual capital charges for each asset comprise:

       - A return of capital, i.e. annual depreciation for each asset listed in the Regulated Asset Base (RAB) determined by the Commerce Commission; and
       - A return on capital. i.e. The Transpower Board's target rate of return limited by the regulated weighted average cost of capital (WACC) determined by the Commerce Commission for the RAB in aggregate.

    c) The fraction of the $300m for unallocated residual capital charges and $200m other unallocated costs including overhead expenses that confer no benefit to those that have to pay is not known for sure. What is known is that Transpower has been, and under the proposed TPM, will be charging for such to parties that receive no net benefit. For example, the consultation paper gives three examples of historic assets where no beneficiaries were identified.[8]

14. Mandating Transpower customers pay for assets and services they receive no benefit from is contrary to the outcomes found in workably competitive markets (WCM). The principle of WCM underpins much of the Part 4 of the Commerce Act regulation that applies to Transpower. WCM is also relevant in considering amendments to the Code; including this review of the TPM guidelines and future detailed TPM proposals by Transpower.[9] The real-world problems with the proposed residual and how they relate to outcomes in WCM are:

    a) Distortions: Parties that pay for assets and services they receive no benefit from will be poorer than in a WCM where a supplier could not pass on such cost. This leaves less monies for those parties to spend on assets and services they do derive a

---

[4] The discussion in this sub-section is relevant to the first part of Q14 [B.68] "Should the cost of pre-2019 investments be recovered in some other manner than through the residual charge, and if so how?"
[5] Consultation paper [5.12] Table 9.
[6] Ibid, actual value $493.8m.
[7] Ibid, [B.194] and footnote 209. MEUG estimates approximate as footnote 209 refers to 2015/16 data.
[8] Ibid [B.147], [H.67] for North Auckland and Northland (NAaN), Otahuhu Substation Diversity and Upper South Island Reactive Support.
[9] Refer consultation paper sub-section titled "Pricing in workably competitive markets" [D.19] to [D.27].

benefit from. Similarly, suppliers of those other assets and services will have less demand and therefore in turn employ less resources and invest in longer-term innovations than would otherwise be optimal. The economy will be worse off.

b) Instability: Parties that pay the residual will have an incentive to reduce their relative share. If the TPM is changed to accommodate some parties at the expense of others, the latter will have an incentive to reverse the change. Hence there will be policy instability. That instability undermines investor confidence by users of the grid. In a WCM a supplier could not make unilateral decisions on cost allocation and mandate prices customers should pay; hence those factors would not lead to market instability.

15. There are solutions to addressing problems with residual charges. The decision makers for those comprise separately or in combination Transpower, shareholding Ministers, the Commerce Commission and the Electricity Authority. For simplicity the next two paragraphs consider those outside and within the remit of the Electricity Authority.

16. First, policy solutions outside the remit of the Electricity Authority. In WCM assets and expenses that confer no benefit to a customer cannot be passed on in prices. The supplier must therefore write those assets off and either cease such expenses or absorb those leading to reduced profits. In relation to residual charges this could either be voluntarily adopted by the Transpower Board (with or without the concurrence of shareholding Ministers) or regulated by the Commerce Commission. The latter would be by way of bringing forward the next review of the Commerce Act Part 4 Input Methodology(s) that regulate Transpower. The former could range from a directive from shareholders to write off assets, or to retain assets on the balance sheet but with no return on capital charged until such time as a payer that benefits is identified.

17. Second, policy solutions within the remit of Electricity Authority. The draft TPM guidelines propose:

a) A single residual charge payable by each Transpower customer. An alternative is considered for multiple residual charges to allow customers to know how much they are charged for sub-components such as [B.195][10]:

- unallocated capital charges;
- unallocated other costs; and
- costs resulting from reassignment.

The consultation paper states, “We are currently minded to provide for a single residual charge, as this approach may reduce administrative burden.” MEUG would be concerned if a change in the TPM lead to reduced visibility of the sub-components of the largest component of transmission charges. At a minimum Transpower should publish:

[10] The discussion in this bullet point is relevant is Q27 in the consultation paper: Should the guidelines provide for a single residual charge or multiple residual charges?

- sub-components of the aggregate total annual residual charge that customers wish to have visibility of; and
- the share of AMD for each customer.

This will allow customers to check their sub-component costs. With such granular information customers will be able to make Transpower accountable, for example, by challenging why any increases in a sub-component such as unallocated other costs have not been allocated to benefit-based charges. This may be a better option than having detailed sub-component charges set out in each invoice; though it's not obvious why that alternative would be administratively burdensome.

b) Clause 62 and 63 of the draft TPM guidelines provide for Additional Component E: Including additional pre-2019 investments in the benefit-based charge. The consultation paper asks [B.334] "Q47. Should the guidelines make applying the benefit-based charge to additional and potentially all pre-2019 investments a core component?" MEUG's view is that Additional Component E should be changed to a core component of the guidelines. We are concerned about weaker incentives on Transpower at their option to consider applying benefit-based charges for pre-2019 assets compared to the alternative we support whereby Transpower must apply benefit-based charges.[11] There will be a cost to Transpower to arrive at an allocation of benefit-based charges and such allocation will likely never be universally agreed. Nevertheless, it is more likely than not that the cost will be lower than the benefits of reducing the pricing/income/production distortions and regime instability discussed in [14] above.

18. An example of a combination of policies within and outside the remit of the Electricity Authority that could be considered follows:

a) Additional Component E would become a core component rather than additional per [17 b)] above.

b) If there are any remaining pre-2019 assets that Transpower cannot in its reasonable view allocate on a benefit-basis, then Transpower's shareholder will either agree to write those assets off or not receive returns of and on capital.

An option with lesser cost to shareholders would be to recover depreciation only. This would leave deprecation costs to be recovered in residual charges; a smaller impost than the proposal for consumers because capital charges would exclude a return on capital.

If subsequently circumstances changed and users that benefited from the assets could be determined, then capital charges would apply through specific benefit-based charges.

In this example the result of the combined policies may create better incentives on Transpower to uncover an optimal level and methodology for allocating benefit-based charges than leaving the easy option to Transpower to leave costs in the residual.

[11] In the alternative supported by MEUG, Transpower retains the overarching flexibility in the proposing implementation details provided in clause 2 of the draft guidelines as noted in [footnote 2] of this submission.

Is there a better denominator than AMD?

19. The subsection titled "Recovering any additional costs" in Appendix D of the consultation paper discusses principles for allocating costs not recovered in benefit-based charges concluding with a sixth principle for transmission pricing [D.84].

> "Any additional costs should be recovered by a charge on load customers designed to affect their behaviour as little as practicable."

20. MEUG suggests the text of that principle does not reflect the analysis in the paragraphs that preceded [D.84]. We think the consultation paper analysis is better reflected in the sixth principle being split into two parts:

    a) "Any additional costs, where the cost of estimating benefits is not prohibitive, that confer no benefit on any user should be a cost to the transmission service provider."

    b) "Any additional costs remaining that do not confer benefits (and by implication the costs of allocating those to beneficiaries is prohibitive) should be recovered using tax policy principles."

21. The first of the above proposed two new principles ([20 a)] above) is consistent with the preceding sub-section of this submission of outcomes expected in WCM. The consultation paper acknowledges that [D.74] "Of course it is possible that past investments were not efficient, either because they were never efficient or because the future turned out to be different from what was forecast at the time of the investment. In principle this could mean there is a difference between the share of benefits that a user actually gets and its share of the cost of the investment." That paragraph then explains how some pre-2019 investments will have benefit-based charges. Missing from the discussion in Appendix D, Elaboration of decision-making and economic framework, is any consideration of pre-2019 investments where future costs exceed benefits. The discussion in Appendix D is in the main, as it should be, at an economic principles level and not constrained by existing institutional and regulatory constraints such as the demarcation between the Authority and Commerce Commission on how Transpower is regulated. The treatment of sunk costs that have no net benefit is a material issue and needs to be considered using broad principles first, with any implementation constraints such as what it is within and outside the remit of the Authority considered transparently. Hence, we think inclusion of the new principle in paragraph 20 a) above is appropriate.

22. The second of the above proposed two new principles ([20 b)] above) is supported by the discussion in [D.81] and footnote 330. We think there is more value in expressing the transmission pricing principle in the broader tax policy principle as discussed in the next paragraph. The proposed principle in ([20 b)] above encompasses the consultation paper's proposed sixth principle in [19] above, i.e. tax is unavoidable and hence doesn't change payers' behaviour.

23. Using a tax policy principle then opens the discussion on the potential policy solution of whether shareholding Ministers' should bear all or part of the cost of historic assets that have no future benefit. Allocating these no-benefit sunk-costs over all taxpayers is an efficient and feasible outcome consistent with tax policy principles. There may be reasons why that option may not be practical but that is not a reason to dilute the principle in the first place.

24. MEUG agrees with the view that historic MWh is an inappropriate denominator for the residual because of the risk of distorting price sensitive customers' investment and divestment decisions.[12] The preferred choice of AMD over MWh is partly driven to overcome this risk and that outweighs the benefit expressed in the consultation paper, that MWh has a benefit over AMD of being a broader measure of historical demand.

25. MEUG agrees that the denominator should support the Authority's approach that "we have designed the residual charge so that it affects the use of and investment in the grid as little as possible" provided this relates solely to assets in place in 2019. In addition to the residual not distorting use of sunk assets in the future the consultation paper discusses two other desirable attributes for the denominator in the context of WCM:[13]

    a) likely willingness of customers to pay; and

    b) likely ability of customers to pay.

26. The relative value each customer gets from the residual service they pay for would be a better denominator than using measures of demand. Assuming the only measurement we have for the residual is to use a measure of demand, then the preferred demand metric should be a better proxy than the alternatives to reflect customers likely willingness and ability to pay in addition to mitigating distortions in use of sunk assets.[14]

27. MEUG suggests historic AMD at an ICP level for every consumer in New Zealand would be a better denominator than the proposed AMD at a GXP level or MWh. This would result in better allocation, for example, to households relative to large grid or near grid connected users reflective of likely willingness and ability to pay. AMD at an ICP level is a closer proxy for the relative Value of Loss Load (VoLL) of different classes of consumer than the alternatives considered in the consultation paper.[15]

[12] Consultation paper [B.201] and [B.202].
[13] Ibid [B2.09], [B.213], [B.222]
[14] An alternative to measures of demand would be contracted levels of supply. That alternative has not been considered in this submission.
[15] If estimates of VoLL were to be used for allocating residual costs this would in effect be a benefit-based charge allocation.

Benefit-based charges

28. Schedule 1 of the draft TPM guidelines prescribes the share of benefit-based charges for seven pre-2019 assets to each Transpower customer. MEUG recommends schedule 1 prescribe those shares on a GIP and GXP basis to align costs with the parties that benefit.

29. Distributors with multiple GXP should pass on GXP specific connection and benefit-based charges to connected customers that are provided services from those GXP. MEUG sees no reason why future benefit-based charges should be GXP specific whereas benefit-based charges for the seven pre-2019 assets are not allocated in the TPM per GXP. As the proposal stands a distributor would have to work through the analysis behind schedule 1 to arrive at a cost allocation per GXP. It would be better for the Authority to be transparent in the TPM guidelines and detail for each GXP and GIP the share of the seven pre-2019 assets.

Cap on transmission charges

30. The proposed mechanics of the cap using the base price year 2019/20 estimated sum of wholesale and transmission charges is unnecessarily complicated compared to the alternative discussed in the consultation paper [B.278] of limiting the cap to transmission charges. MEUG recommends the simpler approach be adopted.[16]

Yours sincerely

Ralph Matthes
Executive Director

[16] MEUG has no view on the quantum of the cap should the alternative in [B.278] be adopted, i.e. whether the 3.5% cap rate should change if [B.278] were adopted.

Appendix: Glossary

$m	million dollars
AMD	anytime maximum demand
CBA	cost-benefit analysis
Code	Electricity Industry Participation Code 2010
GIP	Grid Injection Point
GXP	Grid Exit Point
ICP	Installation Control Point
MEUG	Major Electricity Users' Group
NAaN	North Auckland and Northland
pa	per annum
RAB	Regulated Asset Base
TPM	Transmission Pricing Methodology
VoLL	Value of Loss Load
WACC	Weighted average cost of capital
WCM	workably competitive market