Beyond the Boundaries

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

Dear Jean-Pierre

Re: TPM 2019 Issues Paper: Supplementary Consultation

Introduction

1. This is a submission by Oji Fibre Solutions (NZ) Ltd (OjiFS) on the "Transmission pricing methodology: 2019 Issues Paper: Supplementary Consultation" consultation paper published 11 February 2020.[1] We refer to the consultation paper as 'Supplementary Paper' or 'the Paper' throughout this submission, and refer to the original 2019 Issues paper as 'Issues paper'.

Background to Oji Fibre Solutions

2. Oji Fibre Solutions is an Australasian pulp, paper and packaging products processing business with substantial direct investment in the New Zealand economy. OjiFS exports to global markets, predominantly in Asia, with major competitors spread around the globe. OjiFS is also a substantial employer with over 1400 direct employees based in NZ.

3. OjiFS operates some of New Zealand's largest industrial sites and is one of the largest producers of biofuel renewable energy, with over 80% of our process energy needs derived from renewable sources. OjiFS generates approximately 300 GWh per annum of electricity via cogeneration plants utilising some of this process heat, but nevertheless is one of New Zealand's largest electricity consumers, with gross load in the order of 950 GWh per annum.

4. OjiFS has sites throughout NZ, but has two large electricity points of supply at Kinleith and Kawerau. At present, OjiFS is not a direct connect, but is supplied via various EDBs.

5. OjiFS is a member of the Major Electricity Users Group (MEUG) and the TPM Group. To the extent that this submission does not conflict with anything in the MEUG submission or the TPM Group submission, OjiFS supports and endorses both the MEUG submission and the TPM Group submission.

6. This submission is not confidential.

[1] Refer web page https://www.ea.govt.nz/dmsdocument/26354-supplementary-consultation-paper-transmission-pricing-methodology-2019-issues-paper at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/

Submission Response

General Comments

The Authority's Objectives

7. We note that the Authority has used the argument that changes to the TPM are required in order to promote new renewable generation. However, we make the observation that many of the Authority's proposed changes to the TPM will if anything, undermine Government policy and in particular act as a disincentive for new renewable generation. In particular, we note that the proposal creates a significant disincentive for OjiFS to invest in bioenergy infrastructure in the central North Island.

Issues with the current TPM

8. We disagree with the Authority's view on flaws with the current TPM. In particular, our view is that the RCPD mechanism is an effective means for reducing peak demand and deferring grid investment. We agree that it is perhaps stronger than it needs to be, but that it has the desired effect and provides correct incentives for reducing congestion on transmission and distribution networks.

9. We disagree with the comment that the RCPD charge "inefficiently discourages use at times consumers most value it, even when there are no grid congestion issues". For Oji FS, and indeed most consumers, peak periods are not necessarily the times when we most value it. OjiFS requires electricity 24 hours a day, 365 days a year, and electricity at any one point in time is equally as valuable as at any other point in time. We believe that this is likely to apply to most, if not all, consumers to some extent. Electricity demand is highly inelastic, with significant amounts of load unable to respond to RCPD signals, and the majority of load also insulated from locational marginal pricing signals. Consequently, to move load from peak periods, a strong targeted pricing signal is required to incentivise customers who are able to respond.

10. We also disagree with the following statement that the RCPD charge "encourages customers to unnecessarily invest in technologies such as batteries and distributed generation to avoid paying transmission charge, shifting charges to others without reducing Transpower's costs." While such investment may not reduce Transpower's costs in the short term, in the medium to long term, any deferral of transmission investment does indeed reduce Transpower's costs, and therefore reduces charges to a wider number of customers. We also note that any investment in batteries and distributed generation also reduce the requirement for further investment in both distribution networks and grid-connected generation. Indeed, without such investment in new renewable distributed generation, the marginal fuel source will continue to be thermal generation, thereby increasing carbon emissions.

Supplementary Paper Issues

11. The Supplementary paper proposes four refinements to the Authority's earlier TPM proposal:

    a) a change to the method used to set annual benefit-based charges for new transmission investments;

b) a cap to an assessed beneficiary's obligation to pay benefit-based charges in respect of plant that closes down;

c) the inclusion of an adjustment mechanism for the residual charge based on energy use; and

d) a new right for a transmission customer to apply for a prudent discount if it considers its transmission charges would exceed the standalone cost of the transmission services it receives.

A. Recovery profile for future benefit-based investments

12. The Supplementary paper proposes to change the basis for recovery of benefit-based charges from indexed historic cost (which effectively back loads cost recovery) to depreciated historic cost (which front loads cost recovery).

13. OjiFS <u>does not support</u> the proposed change.

14. Our view is that the proposed change moves away from the service or benefits based pricing. Transmission assets are built ahead of demand and consequently there will be more beneficiaries and benefits later in the assets' life as demand increases. Front loading the cost allocation for investment encourages potential beneficiaries to defer investment, and in particular to avoid being the first mover, whereas back loading cost recovery encourages investment.

15. The bigger issue is how these costs are allocated to customers. It is essential that any new customers which benefit from investments in assets for which costs are recovered using benefit based charges are also required to pay for these assets.

Q1. Should the annual benefit-based charges that recover the costs of post-2019 investments be set using DHC, IHC or some other approach?

16. Benefit-based charges that recover costs of post-2019 investments should be set using indexed historic costs (IHC).

Q2. Should Transpower be required to use the DHC as proposed, or should it be able to propose a different method if that better met the Authority's statutory objective?

17. We believe that Transpower should be able to not only propose a different method if that better meets the Authority's statutory objective, but also propose a different method in order to meet Government Policy Statements and other legislation.

B. Adjusting benefit-based charges when a plant closes

18. The Supplementary paper proposes to cap benefit-based charges paid by a customer that closes down to payment for the first ten years of a new transmission investment only. If a transmission asset is more than ten years old then the benefit-based payment obligation will cease immediately on plant closure. Following the cessation of the payment obligation, benefit-based charges are reallocated amongst remaining beneficiaries of that asset.

19. Our key issue is ensuring grid use and assessed charges align in a timely manner. Therefore OjiFS <u>partially supports</u> the new proposal.

20. We support the Authority's change in direction on this issue to address the current open-ended obligation to pay assessed benefit-based charges. However, our view is that the

obligation to pay should cease from the following pricing year, rather than continue for a period of up to ten years.

21. We note that plant closures can be the result of any number of factors, market events, technological developments or regulatory changes that are beyond the customer's control. It is unfair to penalise the owner of a closing plant by requiring it to continue to pay assessed benefit-based charges for up to ten years after a new transmission investment was commissioned (which was also beyond the participant's control) when it is clearly no longer receiving any transmission services in relation to that plant.

Q3. If a transmission customer closes one of its plants, should its liability for associated benefit-based charges continue indefinitely, cease immediately or cease after a specified period of time has elapsed since the commissioning dates of the relevant grid investments? If the latter, should that period be 5, 10 or 20 years? Should the relevant period be expressed relative to the commissioning date of the investment or some other period?

22. If a customer closes a plant, any liability for associated benefit-based charges should cease as soon as practical. In our view charges should remain for the current pricing year, but not apply from the following pricing year.

C. Regular updates of the residual charge allocation

23. The Supplementary paper proposes that the initial AMD-based allocation is automatically adjusted annually based on changes using a four-year rolling average of customers' gross annual energy usage (measured in MWh), lagged by seven years.

24. Our key issue is ensuring grid use and assessed charges align in a timely manner. Therefore OjiFS <u>partially supports</u> the new proposal.

25. We support the Authority's change in direction on this issue, and agree with the move to annual energy usage. However, we note the Authority's comment that annual energy usage is an indicator of ability to pay, and consider that this would equally apply to setting the initial allocation. We therefore consider that instead of an AMD-based allocation, the initial allocation should be based on annual energy use (potentially averaged across say a four year period).

26. We also consider that **net** annual energy usage is a better indicator of ability to pay than gross annual energy usage. This incorporates historic investments in generation and reduces wealth transfers that particularly target large industrial renewable generation and cogeneration, and also increases incentives to invest in new renewable generation.

27. We agree that an averaging of annual energy use is appropriate, and although we consider a reduced averaging period is more appropriate, we acknowledge a four year averaging period is not unreasonable.

28. We also consider that there should be minimal lag as possible, so as to align charges with ability to pay as promptly as possible. Ideally we would see the four year assessment period ending in a timely manner to allow charges to be adjusted for the following pricing year (e.g. 31 August as is currently used for RCPD calculations). Our view is that using net annual energy use with a minimal lagging period will reduce the risk of misalignment of assessed charges and grid use.

Q4. Should the guidelines stipulate for regular updates to the residual charge allocation?

29. Yes, the guidelines should require regular updates to the residual charge allocation. In our view this should be an annual adjustment.

Q5. If so, is the revised proposal an appropriate way to provide for such updates?

30. The revised proposal goes part of the way to provide for such updates. In our view, the proposal should use **net** energy demand (for the period aligning with the averaging period used for adjusting the adjustment, e.g. 4 years as proposed) for the initial allocation, net energy demand for adjustment (averaged over the assessment period, e.g. 4 years), with as little lag as practical.

D. Prudent discount for charges above standalone cost

31. The Supplementary paper proposes to amend the provision allowing a customer to apply for a prudent discount, to allow for pricing relief for a customer if there is either a material risk that the customer's transmission charges would cause the customer to close down its plant, or the customer can establish that its transmission charge are higher than the standalone costs of supply.

32. OjiFS <u>does not</u> support the new proposal to amend the prudent discount rules.

33. The rationale for this change appears to be based on submissions made by a small number of parties, primarily being Rio Tinto and related stakeholders. We are concerned that a specific change is designed to effectively benefit one participant, knowing that these costs will then be met by other participants.

34. We also believe that there is a significant risk that multiple parties could successfully apply for such a relaxed approach to assessing prudent discount applications, resulting in further increased costs for other participants.

Q6. Should a load customer be eligible for a prudent discount if it can establish that its transmission charges exceed the efficient greenfield standalone cost of supply?

35. Yes, but only in the case where all costs associated with greenfield standalone cost of supply are taken into account, including resource consents, reliability, energy security and market benefits from being part of the interconnected grid. We believe that the existing prudent discount rules already provide for this.

Final Comments

36. The matters raised in the Supplementary paper continue to highlight the flaws with the proposed methodology, and in particular the process taken by the Authority. The Authority has yet to address the more significant concerns identified in submissions on the Issues Paper, being whether the proposal has any benefit to NZ or consumers, let alone meeting the Authority's statutory objective. Instead the Authority has chosen to consult on secondary details related to the proposal. In our view, the primary concerns with the Issues paper need to be addressed before working through the various secondary details.

OjiFS is more than happy to meet with the Authority to discuss our concerns and our suggestions as above.

Feel free to contact me if you have any questions on our submission.

Regards

Darren Gilchrist
Energy Manager