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.”

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[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 <u>at their option</u> to consider applying benefit-based charges for pre-2019 assets compared to the alternative we support whereby Transpower <u>must</u> 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

TPM 2019 Cost benefit analysis

Initial review

NZIER report to MEUG

1 October 2019

About NZIER

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Key points

Scope of this analysis

MEUG has asked NZIER for advice on whether the cost benefit analysis (CBA) for the 'Transmission pricing review 2019' (TPM 2019). Is robust. In view of the complexity of the CBA the scope of this advice has been narrowed to a stocktake of current aspects of the CBA to consider.

Benefit of more electricity use at peak is overstated

Most of the net benefit in the Electricity Authority (EA) Transmission Price Methodology proposal (TPM 2019) cost benefit analysis (CBA) arises from:

- Benefit to distribution connected consumer of much lower electricity prices over the 1,600 peak demand periods (due to the removal of RCPD charge) which encourage them to buy more electricity at a time when it is most valuable to them
- Generators meet the increased demand for electricity at lower average wholesale price than forecast if the RCPD remains in place.

This benefit relies on a future shift by EDB and retailers to a new form of time of use pricing which concentrates the effect of the RCPD charge into a much shorter peak demand period than currently used by EDB.

because the RCPD signal is probably much weaker than estimated in the CBA

For the benefits modelled in the CBA to be realised mass-market consumers need to receive a much stronger price signal about the transmission costs during the EA peak demand period (covering only 1,600 trading periods) than is sent by current EDB pricing.

Analysis of the pricing methodology of the 10 largest EDB[1] which account for about 80 percent of the interconnection charges paid by EDB indicate:

- the typical definition of 'peak demand'[2] period for EDB covers about 4,140 trading periods, approximately 2.6 times the 1,600 peak demand period used in the TPM 2019 CBA.
- Most EDB do not recover their interconnection charges through energy delivered charge only during peak demand periods
- EDB consumers usually include at least three major groups: residential mass-market, commercial and industrial which face different types of transmission recovery charge. However, the CBA modelling treats EDB consumers as a single group.

1 In descending order of EDB revenue: Vector, Powerco, Orion, Wellington Electricity, Unison Networks, Aurora, Northpower, The Power Company, Alpine Energy and Top Energy

2 Weekdays between 7:00 to 11:00 and 17:00 to 21:00 or 16 trading periods per weekday. Some EDB split their ToU price bands into 'day' and 'night'.

and increased generation at lower prices seems unlikely to be the central scenario

The CBA modelling also indicates that average wholesale electricity prices will be on average about one percent lower if the RCPD charge is removed than would be the case if the RCPD change is retained due to increased generation investments. The implication in the issues paper is that wholesale price fall occurs because the increase in demand over peak periods increases the number of periods for which new generation is profitable (possibly because it allows a more efficient mix of generation).

CBA modelling excludes distribution costs

The CBA allows for the need to bring forward investment in the Transpower grid capacity in response to the increase in peak demand but the estimated cost to consumers is low.

The CBA does not allow for the potential need for EDB to increase investment in their network to cope with increases in peak demand but argues that:

- if the investment was required it would be efficient
- EDB have spare capacity.

Discussion of RCPD impact on peaks

One of the arguments that has been made against removing the RCPD charge is that the peak load currently discouraged by the RCPD charge will require grid 'over-build' if the charge is removed. The EA and Transpower have discussed this risk in qualitative terms and the EA has given Transpower the option to make a case for a transitional peak charge – a more pragmatic approach than TPM 2016.

10 year reset for AMD is a major change from TPM and EDB annual reset for

The TPM 2019 discussion of allocators of common or 'residual' charges includes two separate components:

- a proposed change in the denominator from regional coincident peak demand to anytime maximum demand or share of annual load (in response to stakeholder concerns about the 'after diversity' advantage of distribution connected customers)
- setting the allocator using averages over the past 5 year and only changing the allocator with an extended lag of five to 10 years rather than the current approach of annual reset.

The EA argues that choosing allocators that are difficult for grid users to influence by altering their short term grid usage will make the methodology durable and the charging regime more certain for grid users. There are three potential disadvantages to mechanisms designed this way. They:

- embed historical, inefficient, asset usage patterns into the re-allocation of costs
- do not consider the current excess capacity of grid assets
- only respond to changes in asset usage with a very long lag.

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Appendices

Figures

Tables

1 Problem definition

1.1 Under use of the grid

The EA defines the problems to be solved by the TPM as ensuring:

- ensuring efficient grid use and avoiding the RCPD cost spiral[3] which is implicit in the status quo. The EA argues in TPM 2019 that the RCPD charge has a stronger depressing effect on the electricity consumers connected to the distribution networks than on industrial consumers connected directly to the grid. The EA expects this effect will become more severe over time as the prevalence of time of use pricing increases,
- beneficiaries of investment in the grid (though improved reliability or reduced prices) pay for those investments (rather than the costs being shared across all consumers based on their share of the RCPD). The EA concern for this charge is primarily forward looking and is about ensuring allocatively efficient future investment decisions,

1.2 Counterfactual continuation of the current RCPD allocation

The EA assumption is that continuation of the RCPD allocation of interconnection charges seems to be the appropriate status quo for comparison to the proposal given the lack of alternative proposals that had material support from market participants. The two main charges proposed in TPM 2019 'benefit-based' and 'residual allocated using anytime maximum demand (AMD)' are similar to the main suggested charges in TPM 2016.

Transpower consulted on an operational review of the TPM in 2017 but stopped the process without a clear explanation. The proposed changes were limited in scope compared to the TPM 2019 proposal and for interconnection charges included:

- regionalised postage stamp allocation of the RCPD charges and possibly increasing the number of regions
- reducing the strength of the RCPD signal by increasing the number of peaks or basing some of the charges on the long run marginal cost of the next investment

Submitters generally supported an operational review but Transpower did not develop the proposals beyond a high level description

1.3 Preference for nodal pricing as a signal of congestion

The EA also has a strong view that in the long term nodal pricing (locational marginal pricing) is a more efficient signal of congestion on the grid and the need for additional investment in grid capacity than RCPD charges. Nodal pricing is part of the CBA model structure.

[3] Issues Paper page vii

2 Benefits and Costs

2.1 Key benefits

The EA has estimated the net benefits of the TPM proposal at $2.7 billion (with a range of $0.2 to $6.4 billion) comprising:

- $2.4 billion from reducing the wholesale price of electricity and encouraging increased use at peak times when consumers value it most highly
- $0.2 billion from avoiding inefficient in technologies such as batteries to avoid peaks
- $0.1 billion from more efficient investment in transmission and generation by allocating the costs to those who benefit.

Our analysis of the CBA focuses on the estimation of the benefits and risks of the removal of share of regional coincident peak demand (RCPD) as an allocator of interconnection charges.

2.2 Price reductions and volume changes

The price reductions are measured by changes in wholesale prices and are illustrated in Figure 1 of the issues paper. Peak prices fall by the order of 100 percent in 2020 and then follow a track which is 100 percent lower than the baseline until about 2030.

Volume change is driven by estimated elasticity of demand and distribution connected customers (elasticity -0.054 at peak)are estimated to be more than 10 times as responsive to price signals at peak as transmission connected customers (elasticity -0.003)[4] .

RCPD removal alone reduces peak prices by $136 per MWh (48 percent).

More expenditure on electricity from grid-connected generation will increase peak wholesale energy prices but not by much in comparison to the reduction from the removal of the RCPD charge.[5] Modelling indicates energy prices will be 1 percent lower on average over the modelling period due to generation investments.[6] Off-peak prices, initially rise by 19 percent but then fall 30 percent due to increased generation capacity

4 Issues paper page33

5 Issues paper page37

6 Issues paper page 38 4.97, 4.98 and 4.100

3 Assessment of benefits

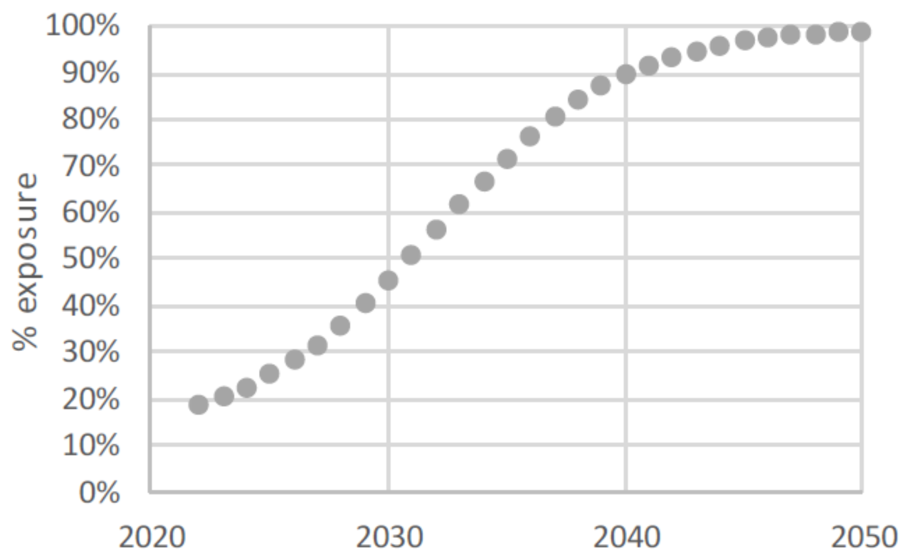
3.1 Benefit of more electricity use at peak is overstated

Most of the net benefit in the Electricity Authority (EA) Transmission Price Methodology proposal (TPM 2019) cost benefit analysis (CBA) arises from:

- Benefit to distribution connected consumer of much lower electricity prices over the 1,600 peak demand periods (due to the removal of RCPD charge) which encourage them to buy more electricity at a time when it is most valuable to them
- Generators meet the increased demand for electricity at lower average wholesale price than forecast if the RCPD remains in place.

The TPM 2019 CBA acknowledges that most (81 percent) of distribution connected consumers are not affected by (retailer) time of use (ToU) pricing[7] and therefore not affected by the concentrated RCPD signal over the peak demand period. However, the CBA modelling assumes that the proportion of mass market consumers exposed to ToU pricing will increase to 50 percent by 2032 and reach 100 percent by 2050 as shown in Figure 1.

Figure 1 Assumed mass market exposure to time-of-use electricity prices



Source: Electricity Authority [8]

This assumption seems to be independent of the changes proposed in TPM 2019 but seems to be the major driver of the increase in benefits from the removal of the RCPD charge over the modelling period. The CBA sensitivity analysis does not seem to include different scenarios for the timing of adoption of TOU charging by both EDB and retailers.

[7] 'CBA approach, methods and assumptions, Technical paper' page 17. The EA implies that the 19 percent affected by ToU tariffs is a low estimate of the starting point. It is not clear from the EA comments whether the ToU tariffs include exposure to just the RCPD recovery or whether they include recovery of EDB charges and exposure to movements in wholesale electricity prices.

[8] 'CBA approach, methods and assumptions, Technical paper' page 18

3.2 The RCPD signal is probably much weaker than estimated in the CBA

For the benefits modelled in the CBA to be realised mass-market consumers need to receive a strong price signal about the transmission costs during the peak demand period under the status quo. As well as the share of consumers on retailer ToU pricing plans the strength of the RCPD price signal felt by distribution connected customers also depends on:

- how electricity distribution businesses pass-through transmission costs to mass-market and commercial consumers.
- the proportion of customers on time of use pricing plans with their EDB

Analysis of the pricing methodology of the 10 largest EDB[9] which account for about 80 percent of the interconnection charges paid by EDB indicate:

- the typical definition of 'peak demand'[10] period for EDB covers about 4,140 trading periods, approximately 2.6 times the 1,600 peak demand period used in the TPM 2019 CBA. The effect on the CBA modelling is that even if the RCPD charge was passed on in full as part of EDB peak pricing, the average price signal would be smaller than that modelled in the CBA and would apply over two of the CBA modelling periods (peak and shoulder) with two different demand elasticities
- Most EDB do not pass-through most of their interconnection charges through per MWh peak demand pricing for several reasons:
  - mass-market consumer adoption of ToU pricing is low (Vector, Wellington Electricity Lines and Aurora)
  - transmission charges are recovered at different rates for peak and off-peak periods (Powerco Eastern network, Northpower) or as a combination of fixed daily and volume charges (Orion, Unison, The Power Company, Alpine Energy and Top Energy)
  - transmission charges are primarily allocated using a combination of peak demand measures (Orion).

Together these factors indicate that the actual peak demand pricing signal sent by EDB transmission cost recovery charges to electricity retailers is not only much weaker than estimated in the CBA modelling but also varies across EDB regions. The CBA assumes that the RCPD signal in the status quo will become more intense over time as consumers are moved to TOU pricing and the interconnection charges are recovered over a much shorter peak period than is currently used by EDB. This requires both EDB to standardise their tariff structures and retailers to pass them on in their pricing. The CBA does not explain why the continuation of the status quo alone would lead to these outcomes.

The following tables compare the definition of peak period, penetration of ToU charging and key customer groups for the 10 largest EDB[11].

9 In descending order of EDB revenue: Vector, Powerco, Orion, Wellington Electricity, Unison Networks, Aurora, Northpower, The Power Company, Alpine Energy and Top Energy

10 Weekdays between 7:00 to 11:00 and 17:00 to 21:00 or 16 trading periods per weekday. Some EDB split their ToU price bands into 'day' and 'night'.

11 The 10 largest EDB recovered about 75 percent of interconnection charges and about 85percent of EDB interconnection charges in 2017/18 based on data in 'Transpower Information Disclosure Schedules F1-6, G1-8, SO1, Year ended 30 June 2018' SCHEDULE F6: REGULATED REVENUE, F6(iii): Customer Charges

3.3 Who receives the RCPD signal?

The main benefit of removing the RCPD based allocation of Transpower interconnection charges modelled for TPM 2019 is the increase in electricity use by EDB connected customers during a peak period defined as 1,600 trading periods.

For this benefit to be realised as modelled for the status quo, EDB need to recover interconnection charges through a price signal that applies to the peak period only and this signal needs to be passed on by the electricity retailer to the consumer. This section compares the assumptions in the TPM 2019 proposal to the current EDB pricing practice for the largest EDB which account for more than 80 percent of the interconnection charges recovered form EDB consumers and more than 70 percent of all interconnection charges.

Table 1 EDB interconnection charges

Interconnection charges for ten EDB

EDB	2017/18 charges			2018/19 charges		
	Value ($m)	Share of total	Share of EDB	Value ($m)	Share of total	Share of EDB
Vector	197.6	28%	31%	183.5	28%	31%
Powerco	89.3	12%	14%	81.6	12%	14%
Orion New Zealand	65.2	9%	10%	65.8	10%	11%
Wellington Electricity	58.3	8%	9%	52.9	8%	9%
Unison Networks	28.0	4%	4%	26.5	4%	5%
Aurora Energy	22.7	3%	4%	19.7	3%	3%
PowerNet	22.6	3%	4%	21.5	3%	4%
WEL Networks	20.8	3%	3%	19.2	3%	3%
Northpower	18.7	3%	3%	17.4	3%	3%
Alpine Energy	13.3	2%	2%	11.0	2%	2%
Total	523.3	73%	83%	488.1	74%	84%

Source: Transpower Information Disclosure Schedules, Year Ended 30 June 2018

3.4 CBA assumptions do not match general EDB approach

The CBA modelling of TPM 2019 makes three simplifying assumption about the pass-through of Transpower interconnection charges into wholesale electricity prices. These assumptions are compared to high level observation about current EDB pricing in Table 2.

Table 2 CBA modelling assumptions and EDB pricing

Indications of that CBA model may over-estimate the strength of the RCPD signal

CBA model assumption	EDB practice	Impact on CBA model
EDB connected consumers can be modelled as a single load group on a uniform price structure	EDB have residential, commercial and industrial consumers on different pricing structures. Industrial and commercial customers account for about half of EDB load but about one third of the interconnection cost recovery	CBA elasticity estimates may overstate responsiveness of commercial and industrial load to a change in price signals
CBA modelled peak is 1,600 trading periods	EDB peak period for those with ToU pricing varies between 2,600 to 4,160 trading periods[12]. Some EDB only distinguish between 'day' and 'night' rates	CBA model overestimates the intensity of the peak price signal because it is concentrated in a period that is 40 to 60 percent of peak period used by EDB
ToU pricing coverage by EDB can be modelled as a charge that is only recovered during the peak period	Nearly all EDB either recover interconnection charges over both peak and non-peak periods or with a combination of fixed and variable charges	CBA model will overestimate the size of the change in peak period electricity price from removal of the RCPD because not all of the

Source: NZIER

The following section describes the recovery of Transpower charges listed in Table 1 as a starting point for estimating the difference in the CBA modelling of the RCPD peak demand period price signal and the price signal that is could be sent by the current EDB pricing if it was fully passed by electricity retailers.

3.5 Individual EDB recovery of Transpower charges

Table 3 summarises the key elements of EDB interconnection recovery.

12 The narrowest definition of peak period for the 10 EDB listed in this section is 07:30 to 09:00 and 17:30 to 20:00 on weekdays. For larger EDB the more common definition of peak period is 07:00 to 11:00 and 17:00 to 21:00 on weekdays.

Table 3 EDB recovery of interconnection charges

Charges used by EDB to recover interconnection charges and peak period

EDB	Share of EDB energy delivered 2018	Main recovery method for residential mass market	Estimated peak demand price signal as proportion of CBA assumption
Vector	26.2%	Uniform c/kWh delivered for residential consumers and fixed demand or daily charges for commercial and industrial consumers	13%
Powerco	15.1%	Combination of peak c/kWh and uniform c/kWh delivered	27%
Orion New Zealand	9.9%	Combination of fixed demand charges (share of RCPD or AMD) and uniform c/kWh delivered	18%
Wellington Electricity	7.2%	Combination of fixed daily charges and uniform c/kWh delivered	14%
Unison Networks	5.0%	Pricing schedules and methodology do not detail how transmission charges are collected but tariff profile looks similar to Vector	13%
Aurora Energy	4.1%	Non TOU c/kWh delivered for residential consumers and fixed demand charges for all other consumers	14%
PowerNet [13]	4.4%	Combination of fixed daily charges adjusted for controllable load and a volume charge '$ per day per kWh'	10%
WEL Networks	3.9%	TOU pricing for nearly all residential consumers with a relatively short peak demand period	64%
Northpower	3.4%	Uniform c/kWh delivered for residential and small commercial consumers. Demand charges for large commercial and industrial consumers	11%
Alpine Energy	2.4%	Uniform c/kWh delivered for residential consumers. Demand charges and uniform c/kWh delivered for commercial consumers. Annual fixed charges for large industrial consumers	9%

Source: NZIER analysis of EDB information disclosures and pricing schedules and methodologies

13 The PowerNet entity listed in the Transpower Information Disclosure (Interconnection charges) does not exactly match the entities listed in the EDB Information Disclosures to the Commerce Commission. PowerNet and Electricity Southland are not listed in the EDB Information Disclosures to the Commerce Commission. For this analysis PowerNet is defined as The Power Company, Electricity Invercargill, and Otago Net Joint Venture.

The initial strength of the change in EDB price signal due to removal of the RCPD charge modelled in the TPM CBA 2019 is overstated to the extent that the:

- RCPD charge is recovered over a higher number of trading periods than the 1,600 periods assumed in the CBA or does not vary with time of use[14]
- EDB connected consumers include commercial or industrial load that is less responsive to the change in RCPD charges than residential consumers.

3.6 CBA modelling excludes distribution costs

The CBA allows for the need to bring forward investment in the Transpower grid capacity in response to the increase in peak demand but the estimated cost to consumers is low relative to the net present value of the estimated benefits but is the largest cost element of the proposal and accounts for 87 percent of the costs of the proposal.

The CBA does not allow for the potential need for EDB to increase investment in their network to cope with increases in peak demand but argues that:

- if the investment was required it would be efficient
- EDB have spare capacity.

This seems to ignore the fact that EDB costs for mass-market consumers are more than twice grid interconnection costs and does not provide any evidence that EDB on average will be more or less in need of additional capacity than Transpower. If EDB need to bring forward investment to accommodate the additional peak demand encouraged by the removal of the RCPD charge this should be included in the CBA.

3.7 EA and Transpower discussion of RCPD impact on peaks

One of the arguments that has been made against removing the RCPD charge is that the peak load currently discouraged by the RCPD charge will require grid 'over-build' if the charge is removed. Transpower prepared a report 'The role of peak pricing for transmission' on this subject in November 2018. The paper considered two case-study scenarios: a partial withdrawal of load control that would require grid investment to be brought forward and a larger withdrawal of load control that did not respond to nodal price increases.

The CBA discussion of the risks of increase in peak demand following the removal of RCPD charges is qualitative rather than quantitative and highlights the limited understanding of the potential volatility in peak demand that could be caused by removing RCPD charges.

The CBA has 'addressed' rather than fully assessed this issue for now by:

- including the cost of bringing forward the grid investment to roughly meet a partial withdrawal of load control
- giving Transpower the option to propose a transitional peak price signal to manage the risk of a large withdrawal in load control, (The EA stipulation that the peak price signal

[14] To indicate the extent to which the CBA modelling overstates the strength of the RCPD signalling we use the estimate from the 'CBA approach, methods and assumptions, TPM issues paper 2019, Technical paper' page 14 paragraph 2.19 that *'approximately 30% of wholesale market expenditure (costs) occur during the top 1,600 trading periods, which account for only 9% of trading periods.'.* This a provisional assumption pending calculation of price and demand data for the selected EDB,

will be transitional reflects the string view of the EA that locational marginal pricing is the most efficient signal of the need for grid investment,)

Giving Transpower more flexibility to propose a transitional peak price signal is a more pragmatic approach than TPM 2016.

3.7.1 Cross-check on risk of load increase with abolition of RCPD

Comparison of the demand by EDB and industrials at say 100 or 200 national coincident peaks with their AMD outside these periods provides a starting point for a rough indication of the potential for increased demand after the RCPD is removed. For 2017 the following direct connect consumers had AMD outside the 200 highest national coincident demand trading periods that was well above their average demand during the 100 highest national coincident demand trading periods: NZ Steel, Norske Skog, Pan Pacific and Winstone Pulp.

4 Common (residual)[15] charge allocators

4.1 RCPD annual reset to AMD or load with 10 year reset

The TPM 2019 discussion of allocators of common or 'residual' charges includes two separate components:

- a proposed change in the denominator from in the denominator from regional coincident peak demand to anytime maximum demand or share of annual load (in response to concerns about the diversity of
- setting the allocator using averages over the past 5 year and only changing the allocator with an extended of five to 10 years rather than the current approach of annual reset.

The rationale in the TPM 2019 proposal for the change is that the 'residual' charges should be treated like a tax, raised as efficiently as possible and be difficult to avoid. The TPM 2019 rationale for replacing the RCPD with AMD or total load is to encourage distribution connected consumers to use the grid more during peak periods.

4.2 Is it 'consistent'

In this section I suggest two other objections to the move to AMD or share of load:

- RCPD is likely to be a better measure of the contribution of consumers to peak demand that justify an increase in grid capacity than consumer AMD because it is an average of periods when the grid is most heavily used
- Setting the allocator on recent history and only amending it after a long lag is inconsistent with the annual reset approach to the allocation of EDB costs and removes an incentive for users to flatten their load profile.

4.3 Contribution to the need for grid expansion

The TPM 2019 rationale for AMD (excluding the reset aspect of the proposal) seems to be that it needs to be measure of peak use that is unlikely to have been tainted by consumer behaviour to lower their share of the measure and reduce exposure to residual charges. However, the CBA focus on AMD does not appear to have considered the following:

- how the maximum demand relates to the peak or average patterns of use for consumers and therefore whether it represents sustained or one-off need for grid capacity
- whether the maximum demand for a consumer occurred at a time of surplus capacity on the grid and therefore does not contribute to congestion or whether it occurs at peak periods and contributes to pressure for additional grid investment.

[15] TPM 2019 occasion use of the word 'common' for grid costs that cannot be allocated on the basis of direct benefit to a subgroup of consumers is a much more accurate description of these costs than 'residual' and avoids creating the impression that these costs are small compared to the other costs.

4.4 10 year reset for AMD is a major change from current TPM and EDB practice

The TPM 2019 discussion of allocators of common or 'residual' charges includes two separate components:

- a proposed change in the denominator from regional coincident peak demand to anytime maximum demand or share of annual load (in response to stakeholder concerns about the 'after diversity' advantage of distribution connected customers)
- setting the allocator using averages over the past 5 year and only changing the allocator with an extended lag of five to 10 years rather than the current approach of annual reset.

This proposed approach does not seem to consider the deficiencies of AMD as measure of individual consumer contribution for requirement for investment in additional grid capacity and is much more rigid and delayed than the EDB approach to using AMD in the allocation of distribution charges to consumers.

4.5 EDB cost allocation approaches

EDB prices are reset annually based on a combination of cost allocators, last year's prices and an assessment of the likelihood that the pricing strategy will comply with price quality path set by the Commerce Commission.

EDB use a combination of indicators to allocate costs across their consumers including RCPD, various forms of AMD number of connections etc as well as the extent to which consumers use the high and low voltage networks based on how they connect to the EDB network and their load profile. Typically, these measures are included in a cost of service model which is used as input into the annual setting of EDB charges for the next year. The costs are recovered through a mix of charges including fixed (per connection per day), energy supplied, demand, capacity and power factor charges.

Appendix A EDB pass-through of Transpower charges

A.1 Introduction

This section provides more detail on how the 10 largest EDB recover transmission charges based on the following sources:

- EDB pricing methodologies and pricing schedules for the 2019/20 (effective from 1 April 2019) for the EDB charges by consumer group, definition of peak period and share of transmission charges recovered from consumer groups
- EDB Information Disclosure Schedule 8 for the period ended 31 March 2018 as an estimate the share of total EDB energy delivered for each consumer group.

Unless otherwise stated the EDB listed below allocate interconnection charges to their consumer groups on based on each consumer group's share of RCPD. However, the type of charge used to recover the interconnection fees varies across EDB and across consumer groups. The charge is generally not concentrated over the 1,600 peak trading period used in the TPM 2019 CBA.

(Connection charges are usually allocated using share of after diversity maximum demand rather than RCPD.)

A.1.1 Vector

Vector recovers transmission charges from:

- Residential and small business consumers though a per kWh charge that does not vary with time of use. (Less than 0.4 percent of transmission charges were recovered from residential consumers through ToU[16] charges over 2017/2018.)
- Commercial and industrial consumers through a fixed charge based on demand
- Non-standard consumers through a fixed daily charge.

The proportions of energy delivered and transmission fee recovery by consumer group are shown in Table 4.

16 The 2019/20 pricing schedule indicates that the number of ICPs on ToU plans have increased but are still a very small proportion of total residential ICPs

Table 4 Vector recovery of transmission charges

Type of charges used to recover interconnection charges and share of energy delivered by consumer group

Consumer group	Energy delivered (share)	Fixed charges		Energy delivered charge	
		Daily	Demand	Uniform	Peak
Residential	40.0%	0.0%	0.0%	53.0%	0.4%
Business	14.5%	0.0%	0.0%	16.6%	0.0%
Low voltage	12.2%	0.0%	5.6%	4.6%	0.0%
Transformer	18.8%	0.0%	11.2%	0.7%	0.0%
High voltage	7.1%	0.0%	3.8%	0.0%	0.0%
Non-standard	7.4%	4.1%	0.0%	0.0%	0.0%

Source: NZIER analysis of Vector Information Disclosure for 2018 and Pricing Methodology for 2019

Vector's share of total energy delivered by EDB was 26 percent in 2017/18.

The estimated recovery of transmission costs by type of charge in Table 4 suggests that for Vector the initial price signal for peak demand is less than 13 percent of the signal assumed in the CBA model (as the RCPD charge is recovered at the same $/kWh rate for all trading periods and only about 13 percent of energy delivered is consumed in the EA peak demand period). The strength of the signal could be reduced to 9 percent of the CBA model estimate (to adjust for the 30 percent of interconnection charges recovered from non-residential consumers).

A.1.2 Powerco

Powerco operates two networks with approximately equal transmission costs but two different methods of cost recovery:

- Western network with transmission costs recovered from:
  - Residential consumers using a charge on energy delivered during Powerco's peak demand period[17] which contains about 4,160 trading periods (about 2.6 times the number of peak periods assumed in the CBA model)
  - Commercial consumers using a fixed daily demand charge based on average contribution to RCPD
  - Large commercial and Industrial consumers (with capacity greater than 1,500 kVA) using a combination of fixed daily charges based on share of RCPD and AMD
- Eastern with transmission costs recovered from:
  - Residential consumers using an anytime charge on energy delivered for about 85 percent of residential customers and a charge on energy delivered during Powerco's peak demand period for about 15 percent of consumers
  - Commercial consumers using anytime charge on energy delivered

[17] This was introduced on 1 April 2019.

- A small group of commercial consumers using peak charges with different rates for winter evening and winter morning peaks, winter day (excluding peaks) and summer day rates[18]
- Large commercial and Industrial consumers (with capacity greater than 300 kVA) using a combination of fixed daily charges based on share of RCPD and AMD

Table 5 Powerco recovery of transmission charges

Type of charges used to recover interconnection charges and share of energy delivered by consumer group

Consumer group	Energy delivered (share)	Fixed charges		Energy delivered charge	
		Daily	Demand	Uniform	Peak
Unmetered	0.3%	0.6%			
Small	54.2%			27.0%	32.2%
Medium	5.2%		4.7%		
Large	9.9%		8.1%		
Large (Industrial)	30.4%		20.2%		

Source: NZIER analysis of Powerco Information Disclosure for 2018 and Pricing Methodology for 2019

Powerco's share of total energy delivered by EDB was 15 percent in 2017/18.

The estimated recovery of transmission costs by type of charge in Table 5 suggests that for:

- Western network the initial price signal for peak demand is about 41 percent of the signal assumed in the CBA model (as the RCPD charge is recovered at the same $/kWh rate over about 4,160 trading periods and 41 percent of energy delivered is consumed in the EA peak demand period).
- Eastern network the initial price signal for peak demand is less than less than 12 percent of the signal assumed in the CBA model (as the RCPD charge is recovered at the same $/kWh rate for all trading periods and only about 13 percent of energy delivered is consumed in the EA peak demand period).

As the Eastern and Western networks are recovering similar amounts of transmission costs the estimated strength of the price signal for peak demand for the Powerco network as a whole is the simple average of the signal for the two networks – 27 percent. The strength of the signal could be reduced to 16 percent of the CBA model estimate (to adjust for the 41 percent of interconnection charges recovered from non-residential consumers).

A.1.3 Orion

Orion recovers transmission charges from:

18 This group is not included in Table 5 because there the amount of energy delivered to this group appears to be small in comparison to energy delivered to the other groups and there was not enough information to allocate the energy delivered to this group to the different charging periods

- General (includes residential and small commercial) connections[19] through a combination of a fixed daily charge based on peak demand and two c/kWh charges – one for weekdays between 07:00 and 21:00 and the other for nights and weekends
- Major (large commercial and industrial) connections through a fixed daily demand charge based on contribution to RCPD, a capacity charge based on share of AMD and a small charge for nominated capacity (included in the AMD charge in the following table).

Table 6 Orion recovery of transmission charges

Type of charges used to recover interconnection charges and share of energy delivered by consumer group

Consumer group	Energy delivered (share)	Fixed charges		Energy delivered charge	
		Demand (RCPD)	AMD	Uniform weekday 07:00 to 21:00	Uniform weekend and weekday night
General	73.8%	43.7%		28.6%	6.4%
Major	26.2%	9.9%	11.4%		

Source: NZIER analysis of Orion Information Disclosure for 2018 and Pricing Methodology for 2019

Orion's share of total energy delivered by EDB was 10 percent in 2017/18.

The estimated recovery of transmission costs by type of charge in Table 6 suggests that for Orion the initial price signal for peak demand is less than 18 percent of the signal assumed in the CBA model (as about 65 percent of the RCPD charge is recovered through fixed charges and the most of the remaining 35 percent is recovered at a uniform rate over 7,280 periods and only about 26 percent of energy delivered is consumed in the EA peak demand period). The strength of the signal could be reduced to 13 percent of the CBA model estimate (to adjust for the 21 percent of interconnection charges recovered from major consumers).

A.1.4 Wellington Electricity Lines

Wellington Electricity recovers transmission charges from all consumer groups using a combination of fixed daily charges and c/kWh of energy delivered charges. The c/kWh of energy delivered charges vary with each group but are uniform across trading periods with in each consumer group.

[19] Orion applies a similar approach to streetlighting and irrigation connections

Table 7 Wellington Electricity recovery of transmission charges

Type of charges used to recover interconnection charges and share of energy delivered by consumer group

Consumer group	Energy delivered (share)	Fixed charges		Energy delivered charge	
		Daily	Demand	Uniform	Peak
Residential	n/a	18.3%		44.8%	
General Low Voltage	n/a	6.7%		17.4%	
General Transformer	n/a	1.2%		10.5%	
Streetlights and Non-metered	n/a	0.0%		1.1%	

Source: NZIER analysis of Wellington Electricity Information Disclosure for 2018 and Pricing Methodology for 2019

The estimated recovery of transmission costs by type of charge in Table 7 suggests that for Wellington Electricity the initial price signal for peak demand is less than 14 percent of the signal assumed in the CBA model (as the RCPD charge is recovered at the same $/kWh rate for all trading periods and only about 14 percent of energy delivered is consumed in the EA peak demand period). The strength of the signal could be reduced to 9 percent of the CBA model estimate (to adjust for the 37 percent of interconnection charges recovered from non-residential consumers).

A.1.5 Unison networks

Unison's price schedules and pricing methodology do not provide information on what charge types are used to recover transmission costs from individual consumer groups. However, in 2018 most of Unison's revenue from:

- Residential consumers came from c/kWh of energy delivered charges at a uniform rate set according to the type of control Unison has over the load. (Unison had a small proportion of residential consumers on TOU pricing in 2018. The peak period for this pricing plan Is weekdays 07:00 to 11:00 and 17:00 to 21;00 covering 4,160 trading periods per year.)
- Commercial consumers came from fixed daily of demand charges.

The mix of Unison's distribution tariffs and revenue and definition of peak periods is similar to EDB like Vector which suggests initial price signal for peak demand is less than 13 percent of the signal assumed in the CBA model.

A.1.6 Aurora Energy

Aurora Energy recovers transmission costs from:

- Residential consumers using a c/kWh of energy delivered charge with different rates for the time of year or whether the load is uncontrolled or controlled but without any narrowly focused TOU pricing
- All other consumer groups a fixed c/kW of demand charge based on the consumer contribution to RCPD.

Table 8 Aurora Energy recovery of transmission charges

Type of charges used to recover interconnection charges and share of energy delivered by consumer group

Consumer group	Energy delivered (share)	Fixed charges		Energy delivered charge	
		Daily	Demand	Uniform	Peak
Residential	45.0%			56.4%	
All other consumers	55.9%		43.6%		

Source: NZIER analysis of Aurora Energy Information Disclosure for 2018 and Pricing Methodology for 2019

The estimated recovery of transmission costs by uniform or demand charge in Table 8 suggests that for Aurora Energy the initial price signal for peak demand is about 14 percent of the signal assumed in the CBA model (as the RCPD charge is recovered at the same $/kWh rate for all trading periods and only about 14 percent of energy delivered is consumed in the EA peak demand period). The strength of the signal could be reduced to 8 percent of the CBA model estimate (to adjust for the 44 percent of interconnection charges recovered from non-residential consumers).

A.1.7 PowerNet

PowerNet includes: The Power Company, Otago Net Joint Venture and Electricity Invercargill. These three EDB recover transmission costs all consumer groups using a combination of:

- Fixed daily charges which vary according to consumer group (determined by fuse size) and whether the consumer has significant[20] controllable load
- Volume variable prices expressed as '$ per day per kWh' and set at the same rate for all consumer groups except for one sub-group of low fixed charge residential consumers.

The PowerNet EDB pricing schedules do not directly state how transmission costs are recovered using the various charges.

[20] At least 25% of the total annual energy consumption is separately metered on a ripple controlled tariff.

Table 9 'PowerNet' recovery of transmission charges

Type of charges used to recover interconnection charges and share of energy delivered by consumer group

Consumer group	Energy delivered (share)	Fixed charges		Energy delivered charge	
		Daily	Demand	Uniform	Peak
Domestic	29%				
Commercial	23%				
Industrial	25%				
Large industrial	23%				

Source: NZIER analysis of Aurora Energy Information Disclosure for 2018 and Pricing Methodology for 2019

The estimated recovery of transmission costs by fixed and energy delivered charges suggests that for PowerNet the initial price signal for peak demand is about 10 percent of the signal assumed in the CBA model (as the RCPD charge is recovered at the same $/kWh rate for all trading periods as only about 10 percent of energy delivered is consumed in the EA peak demand period). The strength of the signal could be reduced to 6 percent of the CBA model estimate (to adjust for the 44 percent of interconnection charges recovered from non-residential consumers).

A.1.8 WEL Networks

WEL Networks pricing schedules and pricing methodology do not provide detail on the type of charges used to recover the transmission costs.[21] However nearly all WEL residential consumers are on TOU pricing with the peak periods specified as 07:30 to 09:00 and 17:30 to 20:00 on weekdays. This implies a WEL peak demand period of 2,600 trading periods compared with the CBA modelling assumption of 1,600 trading periods in the peak demand period.

Non-residential consumers pay a mixture of energy delivered, peak demand[22] and capacity charges[23] (which were the main source of revenue from non-residential consumers in 2018

If WEL Networks recover their transmission costs from residential consumers through peak period energy delivered charges, the initial price signal for peak demand would be about 60 percent of the signal assumed in the CBA model.

A.1.9 Northpower

Northpower recovers transmission costs from:

- Residential consumers using a c/kWh of energy delivered charge with different rates depending on whether the load is uncontrolled or controlled but does not have any residential consumers on TOU pricing
- Large commercial and industrial consumers using either:

21 The WEL Networks Pricing schedule available at https://www.wel.co.nz/UserFiles/WelNetworks/File/Price%20Schedule%202019.pdf states 'ii. The transmission component of the prices listed equates on average to 25% per price component.'

22 Separate rates for winter and summer peaks.

23 Capacity charges were the main source of revenue from non-residential consumers in 2018 and accounted for more than

- a c/kWh of energy delivered charge with different rates depending on whether the load is uncontrolled or controlled or
- c/kVA demand charges with different rates for shares of AMD and RCPD

- Very large industrial consumers using a fixed $/kW/month demand charge.

Table 10 Northpower recovery of transmission charges

Type of charges used to recover interconnection charges and share of energy delivered by consumer group

Consumer group	Energy delivered (share)	Fixed charges		Energy delivered charge	
		Daily	Demand	Uniform	Peak
Mass market	43.0%			58.0%	
Large Commercial (Demand based)	7.9%		7.5%		
Very large industrial	49.1%		34.5%		

Source: NZIER analysis of Northpower Information Disclosure for 2018 and Pricing Methodology for 2019

The estimated recovery of transmission costs by uniform or demand charge in Table 10 suggests that for Northpower the initial price signal for peak demand is about 11 percent of the signal assumed in the CBA model (as the RCPD charge is recovered at the same $/kWh rate for all trading periods and only about 11 percent of energy delivered is consumed in the EA peak demand period). The strength of the signal could be reduced to 5 percent of the CBA model estimate (to adjust for the 42 percent of interconnection charges recovered from non-residential consumers).

A.1.10 Alpine Energy

Alpine Energy recovers transmission costs from:

- Residential consumers using a c/kWh of energy delivered charge with different rates depending on whether the load is uncontrolled or controlled but does not have any residential consumers on TOU pricing
- Commercial consumers (not on TOU pricing) and industrial consumers on (TOU pricing) using a mixture of c/kWh of energy delivered and fixed demand charges
- Large industrial consumers using a fixed annual charge based on demand.

Table 11 Alpine Energy recovery of transmission charges

Type of charges used to recover interconnection charges and share of energy delivered by consumer group

Consumer group	Energy delivered (share)	Fixed charges		Energy delivered charge	
		Annual	Demand	Uniform	Peak
Mass market	29.9%	0.1%	0.0%	31.4%	
Commercial (no TOU)	26.5%	0.0%	8.8%	24.2%	
Industrial (TOU)	21.6%	0.0%	11.9%	6.2%	
Large Industrial	22.0%	17.3%	0.0%	0.0%	

Source: NZIER analysis of Alpine Energy Information Disclosure for 2018 and Pricing Methodology for 2019

The estimated recovery of transmission costs by uniform or demand charge in Table 11Table 8suggests that for Alpine Energy the initial price signal for peak demand is about 9 percent of the signal assumed in the CBA model (as the RCPD charge is recovered at the same $/kWh rate for all trading periods and only about 9 percent of energy delivered is consumed in the EA peak demand period). The strength of the signal could be reduced to 6 percent of the CBA model estimate (to adjust for the 36 percent of interconnection charges recovered from industrial and large industrial consumers).