



Date:

1 October 2019

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Transmission pricing review

2019 issues paper consultation

Final

Submission to the Electricity Authority

From the Electricity Networks Association

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1. Introduction

1. The Electricity Networks Association (ENA) appreciates the opportunity to make a submission to the Electricity Authority (the Authority) in respect of the **2019 Transmission Pricing Methodology Issues Paper consultation (TPM3)**.
2. The ENA represents New Zealand's 29 electricity distribution businesses (EDBs) or lines companies, who provide critical infrastructure to NZ residential and business customers. Apart from a small number of major industrial users connected directly to the national grid and embedded networks (which are themselves connected to an EDB network), electricity consumers are connected to a distribution network operated by an ENA member, distributing power to consumers through regional networks of overhead wires and underground cables. Together, EDB networks total 150,000 km of lines. Some of the largest distribution network companies are at least partially publicly listed or privately owned, or owned by local government, but most are consumer or community trust owned.

2. ENA submission summary

3. We understand that the components of the TPM3 proposal have changed from the previous 2016 proposal (TPM2) and the supplementary consultation proposal that followed in February 2017.
4. The Authority now proposes the following TPM3 components:
 - i. a connection charge to recover customer specific connection assets
 - ii. a benefit-based charge on generation and load customers to recover costs of new grid investments and the depreciated costs of seven historic grid investments
 - iii. a residual charge to recover remaining costs from load customers in a least-distorting way.
 - iv. Make the current PDP more flexible to avoid load disconnecting from the grid.
 - v. Staged commissioning of the TPM over the life of transmission assets
 - vi. Possibly a transitional peak charge
 - vii. A possible extension to the benefits-based charge to include additional pre-2019 assets (that is, increase ii above)
 - viii. customer specific opex charges
 - ix. a kvar charge
 - x. a cap on the % annual change to TPM3 charges on EDB's and direct-connected customer bills
5. The ENA supports the need for change to correct the small number of issues with the current TPM which has clearly not kept pace with the broader environment within which the allocation of transmission costs takes place. We are however mindful of the need to manage any change in a low risk manner and avoid extending the period of aggravation that has been part of the TPM review over recent years. We feel that now is the time for the industry to agree a way forward so that Transpower can get on and develop the TPM3 details and the implementation arrangements in a low risk and enduring manner.

6. We are facing a period of change through the next decades that is best contemplated with the re-allocation of Transpower's costs settled in a manner that is sympathetic of the uncertainty that this period of change brings. TPM3 therefore needs to be adaptable as the future unfolds. Setting it in concrete in an unchanging manner as is proposed in the TPM3 consultation, is unlikely to resolve the controversies that have dogged transmission pricing in the past and will leave the TPM3 as increasingly unfit-for-purpose over time.
7. Our approach to this submission is to consider the merits of the proposal compared to the current TPM, to consider the impacts on ENA members, and, as best we can, to review where the costs and benefits fall – that is, will TPM3 provide improved economic outcomes as the Authority suggests.
8. This ENA submission is informed by the following guidelines that we consider could be used to steer the TPM reforms that Transpower will develop. Our suggestions for guidelines are quite specific to transmission pricing rather than being generic to broader network pricing (efficient and cost reflective for instance), as follows:
 - #1 Shedding load to avoid peak-period transmission charges may be a rational economic response by grid users and it could deliver benefits to the grid – it should only be of concern when it results in material cost shifting amongst consumers.
 - #2 The TPM should retain a peak-period transmission charge because it conveys valuable information about the costs of grid use, that other pricing mechanisms cannot do.
 - #3 In the presence of a peak-period charge, there is less of a need for a benefits-based transmission cost allocation approach – it will increase dispute costs in almost all cases where benefits are already clearly broadly based.
 - #4 Therefore, the Authority's TPM guidelines should not be overly prescriptive and should provide Transpower with flexibility to develop the detailed design features for a revised TPM along with appropriate implementation and transition arrangements.
 - #5 Transpower should be given adequate time to incrementally introduced TPM changes to manage bill shocks (if needed), to maximise stakeholder understanding, and to avoid risks of unintended consequence.
9. From the Authority analysis, and our own, the impacts of TPM3 fall in a different way that those of TPM2 in 2017 – that is, while the basic structure of TPM3 is the same as for TPM2, the re-allocation of Transpower's costs across connected customers has changed. We note that consumers end up shouldering an even greater share of Transpower's costs. ENA members will submit on their own behalf on these aspects of the Authority proposal and therefore this ENA submission does not comment on the localised impacts of the benefits-based component of the TPM3 proposal.
10. So, turning to the TPM3 proposal from the Authority, the ENA considers that it can be improved upon, with an eye on the reform guidelines that we propose and our submissions on improvements fall into 5 areas:
 - Cost allocation. We still struggle to understand how changes to the allocation of sunk grid costs can improve economic efficiency (with the possible exception of the HVDC). Accepting that allocation changes cannot do so, it seems to us that the TPM3 approach is simply a matter of believing that

benefits will arise from the reallocation of many millions of dollars of Transpower's costs to different consumers through the benefits-based charge and a residual. For us the process will result in further disputes and avoidable costs.

- Durability and disruption. The ENA still consider that Transpower could make targeted changes over time to the existing TPM that would improve outcomes and avoid the material issues that will emerge as Transpower develops and implements the Authority's TPM3 proposal. Changes to the existing peak period charges could soften current demand side impacts (avoidance) and make the TPM more enduring.
- TPM structure. We observe that the Authority now considers that nodal pricing is a fully efficient signal that can direct use of location specific grid resources. The ENA retains a different view. Nodal pricing may be an efficient method of ensuring least-cost dispatch but in our view, it does not provide an enduring locational peak period signal for use of the grid.
- Network pricing. The ENA remains concerned about reforms to the pricing arrangements across transmission, distribution, and distributed generation that are underway. These changes to pricing need a coordination process so that the objectives, developments through time, and the implementation timelines for each can be managed for best results to consumers. We note the major distortions to pricing signals that result from EDBs being restricted by the LFC regulations on how transmission charges are passed through to retailers and consumers.
- Price cap. The ENA regards the inclusion of a cap on changes to TPM3 charges for grid connected customers to be arbitrary and it provides little protection against price rises. It also results in a transfer from consumers (via EDBs) to some generators and direct connected large businesses. This is a black mark on the fairness and efficiency of the proposed changes to TPM3.

ENA recommendations

11. The ENA therefore consider that TPM changes should focus, in a manner of our guidelines, on the core issues that relate to economic pricing signals and the recovery of embedded grid costs, as follows:
 - i. On the question whether nodal pricing provide an adequate locational price signal, ENA submits that a peak period charge of some sort must be employed in an enduring way to ensure that clear peak period pricing signals are available to grid users over the medium term, and ultimately to end consumers as they consider consumption and investment options.
 - ii. ENA only supports re-allocating costs where it would clearly improve efficiency, however we consider that the benefits-based charge, as proposed, is arbitrary and will impact TPM durability. We recommend that any benefits base methodology should be limited to specific situations that correct a distortion in the market or improve efficiency – the recovery of sunk costs should default to a broad-based framework for simplicity and the avoidance of disputes.
 - iii. Because the point of TPM aggravation moves from the Authority to Transpower, the ENA recommend that Transpower be given flexibility to encourage peak demand management if it emerges that the consequences from the removal of the current peak charge are material. This flexibility needs to come with a set of high-level criteria that can guide how Transpower exercises its discretion.

- iv. While the ENA considers that there are (non-trivial) undesirable aspects to changing the TPM after substantial grid investment has been made to the benefit certain parties, we recommend that any change to allocations must take place over an extended transition period to minimise issues that will flow from the reallocation of Transpower's costs. The extended period that we have in mind is materially longer than the period of the price cap in the TPM3 proposal.
- v. We are supportive of the Authority desire for Transpower to develop a TPM3 that is efficient, equitable and cost reflective, which together will make it more robust and enduring. The earlier versions of TPM change were quite prescriptive and targeted at specific detailed problems that we and other stakeholders took issue with. We encourage the Authority to give Transpower scope to develop and implement a TPM that is principle based, is largely free from controversy and can be enduring.

3. A proposal to change the TPM

12. The Authority has published a consultation paper that proposes changes to the current TPM guidelines.
13. In the same way as the 2017 proposal, this TPM3 sees the Authority back off being very specific with much of the detailed design but is quite specific about how the allocation of Transpower's costs should be structured and the 'stickiness' of the resulting charges. In principle the ENA considers this could be a good thing, provided that Transpower is given the time and discretion to evaluate the options and trade-offs that will emerge through the TPM development process. Despite saying this, we do have concerns with the TPM3 proposal as follows.

3.1 Transmission pricing problems

14. The material reallocation of Transpower costs results in consumers shouldering an even larger share than was proposed in the 2017 paper. ENA's detailed views regarding the Authority's published perceptions of TPM problems were covered in pre 2017 ENA submissions and will not be repeated. We still question whether there are material problems with current cost allocations that need a major rebuild of the TPM.
15. We retain our strong views on the need for transmission pricing to intersect well with distribution pricing, given the work underway among the ENA membership to improve the efficiency of distribution pricing. The ENA wants to avoid replacing problems that are perceived with the existing TPM, with real-world problems to economic network pricing in the future. In this regard, we draw the Authority's attention to the following:
 - At its core, TPM3 is partly principle based as it attempts to attribute some grid costs to those who benefit from its use. It is unclear whether the final design of TPM3 will be compatible with efficient distribution pricing because each has different focus – TPM3 is targeted at unavoidable allocation of grid costs whereas distribution pricing reform is focussed on supporting efficient consumer choices with distribution services. We are unsure how the Authority reconciles the concept of cost-reflective, pricing providing consumers with choices about the services they receive, when at the same time such cost-reflective for transmission is designed to eliminate choice for deemed transmission customers about the services they receive.
 - The ENA agrees in part with the Authority that the current peak demand charge is too sharp and needs to be recalibrated to soften its impacts that see some parties trying to avoid it. Rather than eliminating the peak demand charge, as TPM3 proposes, we consider that there are low risk ways of minimising the potential for avoidance of transmission charges.
 - We also agree in part with the Authority that the current treatment of HVDC costs could lead to inefficient investment decisions by generators. We do not, however agree that the implementation of a benefits-based re-allocation of these costs will solve this issue.
 - We still struggle to agree with the Authority view that TPM3 will improve incentives on customers/consumers to scrutinise investments in the transmission grid. However, we are also of the view that if customers are made aware that they have the option to scrutinise grid investments and if they choose not to, then they bear the costs of that choice.

16. In summary we question the materiality of the problems that the Authority perceives result from the current TPM. As noted, we agree in part with two issues, but we feel that the Authority board should take a less prescriptive approach to these issues and consider using something like the TPM reform guidelines that we suggest in section 2.

3.2 Low fixed charge regulations inhibit pass-through

17. In the past the ENA was generally dissatisfied with the approach to TPM reform and with the detail contained in the 2014 and 2016 TPM2 issues papers. In previous submissions the ENA encouraged the Authority to rethink their approach to make TPM3 robust and durable.
18. We don't see that TPM3 will be robust and enduring. At its core TPM3 is a re-allocation of Transpower costs among its directly connected customers – what happens to them beyond EDBs is assumed away as a separate process and the impacts of the changes are ignored. Other than the rate at which the re-allocation transitions over time (the capping mechanism), there is no real-world recognition of how the changes to the allocation of costs will be reflected in EDB pricing, how retailers will handle EDB pricing and what if anything consumers will see of TPM reform.
19. The key assumption is that, early on, marginal prices faced by consumers will decline substantially due to the movement from RCPD to a fixed allocation. Consumption will increase as a result of this change. This is an extremely unlikely outcome. EDBs are significantly constrained in the way in which they can set variable network prices, particularly for residential consumers due to the Low Fixed Charge Regulations.
20. It is impossible to set the marginal peak signal at the effective RCPD rate, and conversely, if the residual charge becomes fixed, EDBs will be unable (under Government policy) to purely recover transmission charges through fixed distribution charges to residential customers. ENA submits that a movement from RCPD to a more fixed charge is likely to have far more negligible impact on marginal distribution prices than has been modelled in the TPM3 proposal.

3.3 TPM components

Connection charge

21. No comment at this time.

Benefit based charge

22. Because the ENA has a variety of views amongst its members regarding benefits-based charges, EDBs will make their own submissions on this component of the proposal. We would however provide some general commentary on the proposal that may be useful.
23. We note that some transmission assets (NAaN is an example) that had positive benefits under TPM2 in 2016, are assessed as having nil benefits under TPM3 (but may have positive benefits at some stage in the future). This suggests to us that if NAAaN was decommissioned consumers would be no worse off, which is of course nonsense simply because NAAaN provides reliability benefits to the upper North Island which are not accounted for in the TPM3 proposal. The big weakness with the vSPD methodology that underpins the benefits-based component in the proposal is that it misses these benefits. This problem with the vSPD

approach will also impact all seven of the assets that are subject of the benefits-based methodology and, if Transpower is required to use the same approach for future investments, to those future assets as well. Because of this material practical issue, we consider that the Authority should review the inclusion of benefits-based charges for historical assets in TPM3.

24. If it goes ahead, the impact of the benefits-based charge in the TPM3 proposal will not be clear until Transpower develops the methodology but it will for certain remain contentious because of its arbitrary nature. In the end it will however depend on the final scope of the benefits-based charge mechanism (that is, whether it includes all 7 assets as proposed, or just HVDC or some other choice of assets to include).
25. We consider that there are undesirable aspects of changing the TPM after a lot of grid investment has been made to the benefit certain parties, and we do not support a retrospective benefits-based charge. However, the ENA could consider supporting a forward-looking benefits-based charge that has clearly identifiable local benefits from grid investments (as opposed to broadly based benefits) but only if the benefits can be forecast over the life of the investment with some accuracy. As commented elsewhere in this ENA submission we have reservations as to whether this is at all possible.
26. We also question the use of depreciated historical cost as the base for the benefit-based charges because this will result in decreasing price levels as the assets age and a price step up as they are replaced. This will certainly compromise allocative efficiency. If this component of the TPM3 proposal is targeted at limiting the potential for customers to overpay for these assets, it is unnecessary because Transpower's revenue is a zero-sum game – it is all recovered through one allocation mechanism or another.
27. Our last point here relates to Transpower's ability to accurately estimate the 30 to 50-year private benefits from transmission assets, especially when facing the type of changes that are contemplated for the electricity industry. We consider the approach will most certainly result in more dispute and non-trivial cost to the economy.

Price cap

28. Accepting that the TPM2 modelling was indicative at best, in 2016 the Authority decided to include a capping mechanism to limit the potential adverse impact on consumers. The TPM3 proposal includes a cap that limits the increase in the annual bills for 'capped transmission charges' for all end customers to 3.5% pa above the reference years (2019/20), for 3 years after TPM3 comes into force. In other words, if the combined end consumers bill to, say, Vector, increase by more than 3.5% in 2020/21, then the excess above the 3.5% is recharged to other grid users with less than 3.5% increase. In year one TPM2 saw \$34 million transferred under this capping approach, while this has been reduced to \$16.1m under TPM3.
29. The ENA considers that the mechanism as proposed is still likely to deliver distorted outcomes and impact the durability of (transmission and distribution) network pricing over time. We note that the capping mechanism only applies to a subset of total transmission charges (the residual and the benefits-based charges for 7 assets) and will not include any future assets, or an increase in the 7 assets, should Transpower decide to add these to the benefits-based charge.

30. While we agree that a transition is sensible, the capping mechanism as proposed will do precious little to limit the impacts of the TPM3 proposal on customer bills (distribution charges will certainly increase if the TPM3 proposal comes anywhere near having the impacts that it assumes and we consider it likely that spot prices will in reality increase, not decrease as is assumed in the CBA).
31. We suggest that a more orderly transition could come from spreading the price reductions (for example to Meridian and NZAS) out over a longer period and fund the cap that way. This would avoid the reallocation of price increases among (mainly) load customers, some of which are large. There are also technical issues with the proposed timing of the base prices against which the annual increases will be measured (WACC reduction in 2020 and the 5-year measurement year starting 2018).

Residual

32. The Authority's core objective for the residual is that grid users should be unable to avoid it. The Authority has set out a schedule of further "principles" to guide Transpower to achieve this outcome, however the schedule does not define the allocation mechanism, referring to the use of "historical AMD or another method". Importantly the Authority expects that both the residual charge and if necessary, the benefits-based charge, to be "fair" – specifically that they will result in broadly equivalent charges for customers that are in broadly equivalent circumstances. We do not see that this is possible when residual charges are applied to only load and not generation who share use of the transmission grid.
33. Depending on choices that the Authority makes with other components (or it decides to leave the choices up to Transpower) the residual will change shape over time – it will reduce under a benefits based regime as proposed and will likely also reduce in size as the RCPD charge is replaced with a peak demand pricing mechanism. We note the overall increase in size of the TPM3 proposal residual compared to TPM2.

Signal of peak demand costs

34. The ENA acknowledge that nodal pricing is reasonably efficient in the short run (though some inefficiencies do arise from a variety of sources), but it is no replacement for an enduring peak demand pricing component. A peak-demand charge is necessary for locations where congestion will require additional grid investment. The existing peak demand charge was presumably developed with this issue in mind (with the different number of periods used to determine chargeable peaks in different parts of the national grid). It directs a material demand response.
35. Removing the current peak charge without another similar peak demand charge is of concern to ENA members. If it is structured appropriately, a peak-demand charge targets efficient peak demand response and allows ENA members to efficiently manage their networks.
36. We consider that the Authority can achieve its objective of minimising avoidance behaviour, especially when grid level battery storage is an economic option by using a well-structured peak demand charge which will "pressure" grid users away from avoidance behaviour.
37. The arguments in favour of a location specific LRMC charge were core to the Authority 2014 working paper on LRMC charges. Between that time and the 2016 TPM2 Issues paper, the Authority left the inclusion of a LRMC charge as an open question, however TPM3 proposal moves further away and now requires Transpower to demonstrate the need for a locational price signal over and above that provided

for in nodal pricing. In the ENA's view the 2014 paper has already demonstrated this need and we would be surprised if Transpower does not argue strongly for the permanent inclusion of a peak demand charge.

Use of AMD

38. The Authority's has previously proposed using "AMD or some other allocator" as the allocator for Transpower residual costs which was met with a wall of opposition. We note that the impacts of using gross or net AMD, or another measure (e.g. consumption) differs across ENA members. Hence, as with the re-allocation of historic grid costs via a benefits-based charge, the ENA has not commented on this aspect of the TPM3 proposal. ENA members will submit on this issue on their own behalf.
39. We would however make some observations on aspects of the AMD proposal. First, it seems to us that the Authority wants to allocate the residual based on customer size and ability to pay. EDBs with several GXP's will have non-coincident AMDs added together. This is not a good measure of relative size simply because EDBs have differing peaks summer and winter in parts of their networks.
40. Secondly, we consider that the AMD measure as proposed favours large load who have flatter demand profiles compared to EDBs who have peaky retail type loads. It is not clear to us why the Authority has a preference to favour large load customers over EDBs in both this regard and with the proposed price cap.

3.4 Process and durability

41. Our submissions here fall into the following categories:

Transpower's discretion

42. Within the TPM3 proposal there is a lot of scope for Transpower to suggest variations to the basic TPM3 structure – but this is subject to EA approval. We consider that this will leave Transpower in a difficult position of being ham-strung in using its discretion and will have the effect of shifting the point of aggravation about TPM from the Authority to Transpower.
43. These conditions also leave Transpower with considerable legal and commercial risks because they have to address the real-world issues with network pricing rather than assume them away. We note the provisions in the TPM3 proposal whereby the Authority can direct Transpower to implement particular components or the Authority can do so itself.
44. Combined, these provisions will likely result in protracted legal and commercial issues that will leave the TPM situation little different to that which currently prevails. Because Transpower must apply a lot of judgement when making cost allocation models work to calculate benefit-based charges, we consider that there must be high threshold for parties to challenge or otherwise delay the TPM implementation process.

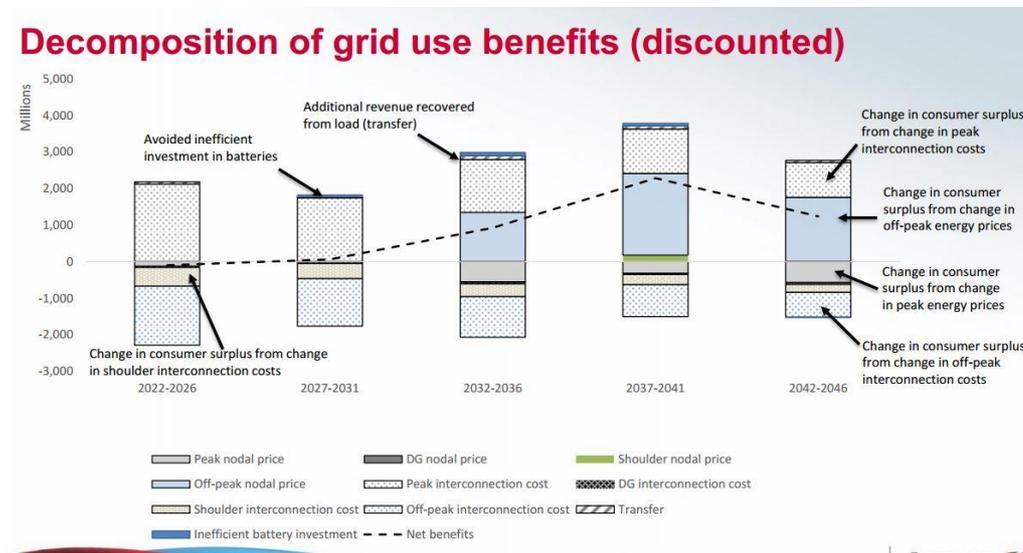
Implementation timing and process

45. The ENA also consider that Transpower is not being given a lot of time within which it needs to develop and implement TPM3. Unchanged, the proposal further increases the risk that Transpower will get parts

of TPM3 “wrong” - which means early aggravation and increasing commercial and regulatory risk for both them and their customers.

CBA usefulness

46. The ENA has an interest in the CBA because of the key issue of pass-through of transmission (and distribution) charges to consumers. This will impact the durability of TPM3 as proposed. While the assumptions in the CBA may be applicable to direct connected customers, for anyone connected via a distributor, pass-through of transmission charges is a key issue and is inhibited by the LFC as we describe above. We do not consider the CBA assumption that ignores pass-through is reasonable, because demand patterns of mass market customers are influenced by the presence of and nature of pass-through. In this regard we found the following chart enlightening, (this chart was not part of the published consultation material).



47. Our interpretation of this material is that the single source of benefit that tips the CBA into net positive territory is the assumed reduction in average nodal prices (to \$75?) that is timed to take place in 2034 (the light blue block in the centre of the bars in the chart above). Outside of this assumption it looks to us like the benefits and costs more or less balance each other out over time, if the CBA is to be believed (we observe that this price reduction is assumed to take place immediately following a substantial amount of generation investment – we suggest this assumption is not credible as it would hollow out the profitability of those generation investments which would not take place under these nodal price conditions).
48. We observe that there are two stages to the price reductions that drive the bulk of the net benefits – in 2024, driven by the removal of RCPD and in 2034, based on a CBA assumption. The 2024 assumption is that peak interconnection charges drop away but off-peak increases (they more or less offset each other) while the 2034 episode is a nodal price reduction which deliver the substance of the consumer surplus.
49. We have undertaken some high-level checks on the assumptions underlying the analysis of benefits which leave us questioning whether the consumer benefits will be realised at all. For the ENA, the Authority has moved the goal posts somewhat – in the CBA section of the 2017 Supplementary paper it was determined

(para 4.14) that the impact of TPM2 on consumer prices should be excluded from the assessment of benefits and regarded as wealth effects. The 2034 price reduction assumption in the CBA gives rise to a direct transfer of existing wealth from generators to consumers for electricity that would have been consumed anyway (plus a small efficiency gain from increased consumption). We consider that the transfer should be excluded from the assessment of benefits.

50. We are unsure about the reasons for the Authority to change its mind – that is its current belief that that the efficiency effects from TPM3 can now be realised through nodal pricing. In the 2016 CBA the major portion of net benefits of more than \$200m were made up of improvements in allocative efficiency from reallocating HVDC to load, and productive efficiency improvements from better generation and transmission investments decisions. Market derived dynamic efficiency improvements to consumers were not on the table at that time.
51. Starting in April 2020, EDBs are implementing a programme of reform to distribution pricing which will (initially) see time-of-use pricing more widely adopted with capacity and/or demand pricing options added later. Based on our analysis of the impacts of pricing options our estimates of the ToU pricing premium at peak averages 3.4c/kwh across EDBs, with a range between 1 to 11c/kwh. It is the ENA view that distribution price changes at these levels will swamp any consumer benefits (we estimate these at a maximum 0.5c/kwh net reduction if the CBA is to be believed) that are implicit in the TPM3 CBA.
52. Two other comments are worth recording – first, we also note that another price increase for consumers will come from the reallocation of \$75m pa of transmission assets to generation via the benefits-based charge. This will undoubtedly find its way into peak nodal pricing, further diluting the CBA price reduction effects. It is entirely unclear whether consumers will even see a price effect from changes to TPM3 let alone whether they will respond by driving more peak consumption. Second, we observe that the costs to meet the increase in consumer demand following the removal of RCPD in 2024 are not included in the CBA. There will be real costs to generators and distribution networks to meet peak period demand growth, and likely Transpower as well.

3.5 Concluding comments

53. The ENA considers that the process of TPM change needs to be brought to a close and Transpower be able to get on with detailed design of the various elements. As proposed, TPM3 is unlikely to allow Transpower to successfully undertake that task and deliver positive outcomes for grid users and consumers. There is simply too much wrong with TPM3 for it to be able to resolve the problems that are agreed to exist with the current allocation of Transpower's costs.
54. We consider that the benefits that the Authority believes will flow from the proposal cannot be realised and that there is a real likelihood that there will be net costs to the New Zealand economy and a loss of efficiency within the electricity industry.
55. We encourage the Authority to allow Transpower to develop its own improvements to the current TPM components that are guided by the "rules" of the type we propose in this submission.

4. Appendix 1

The Electricity Networks Association makes this submission along with the explicit support of its members, listed below.

1. Alpine Energy
2. Aurora Energy
3. Buller Electricity
4. Counties Power (mostly supports)
5. Eastland Network
6. Electra
7. EA Networks
8. Horizon Energy Distribution
9. Mainpower NZ
10. Marlborough Lines
11. Nelson Electricity
12. Network Tasman
13. Network Waitaki
14. Northpower
15. Orion New Zealand
16. Powerco
17. PowerNet
18. Scanpower
19. The Lines Company
20. Top Energy
21. Unison Networks
22. Vector
23. Waipa Networks
24. WEL Networks
25. Wellington Electricity Lines
26. Westpower