Date:

26 July 2016

Name of submitter:

Electricity Networks Association

Industry/area of interest:

Utilities/infrastructure

Contact details

Graeme Peters, Chief Executive

Address:

Level 5, Legal House

101 Lambton Quay

WELLINGTON 6011

Telephone:

64 4 471 1335

Email:

gpeters@electricity.org.nz

Transmission pricing methodology:

Second issues paper

Submission to the Electricity Authority

From the Electricity Networks Association

Contents

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 **2016 Transmission Pricing Issues paper (TPM).**

2. The ENA represents all of New Zealand's 26 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 owned by consumer or community trusts.

2. Submission summary

3. The ENA understands that the key aspects of the Authority's proposals to recover Transpower revenue are as follows:

    - Area of Benefit (AoB) charge to load and generation based on the Authority's assessment benefits from specific transmission assets.
    - Residual charge to load only, likely based on load capacity.
    - Possibly a long run marginal cost (LRMC) charge.
    - Extended prudent discount scheme administered by Transpower.
    - Additionally, the Authority has abandoned the schedule – price –dispatch (SPD)-based proposals that featured in previous TPM proposals.

4. From the ENA's understanding of the proposals, the impact of the proposed TPM will have the following effects:

    a. A substantial reallocation of the sunk costs of transmission investments under the AoB charge;

    b. The Authority intends that residual transmission charges and AoB should become more unavoidable, albeit that if there is a significant change in grid use, former deemed beneficiaries will be able to escape AoB charges through the application of an optimisation test;

    c. The Authority considers that applying the AoB to recent sunk investments will increase the credibility of AoB charges and encourage future potential beneficiaries to engage more actively in transmission investment decisions;

    d. Transpower should consider an LRMC charge which would have the potential to signal future transmission costs if capacity demands continue to increase in certain parts of the transmission system;

e. Applying an extended prudent discount scheme to large customers based on economic criteria, rather than the potential for uneconomic bypass.

5. The ENA itself does not take a view on the appropriateness of the substantial reallocation of costs under the AoB charge, but notes that the overall impact of the scheme is to increase costs on consumers in order to gain efficiency benefits. The ENA is extremely doubtful whether these benefits will occur, especially in light of what appear to be substantial errors and untenable assumptions made in the cost benefit analysis (CBA).

6. It is not clear that the proposal passes the durability test. The current TPM is deemed by the Authority to not be durable because of the distinct treatment of the high voltage direct current (HVDC) which is operated as an interconnection asset. Yet under the proposal there will be an arbitrary delineation of assets subject to the AoB charge based on when the assets were built. This would fail the durability/equity test in respect of the same types of assets being subject to different treatments.

7. A fundamental principle of economics is that the allocation of sunk costs should not influence future decisions. There is no logical nexus between reallocating sunk assets and the credibility of an AoB charge applied to future transmission investments. This reallocation can only be based on equity considerations between customers, but arguably this sits outside the Authority mandate.

8. The application of an optimisation test to AoB assets, which could be removed to the residual charge would seem to diminish incentives on deemed beneficiaries to identify optimal transmission solutions because if an investment subsequently turns out to be not required then the costs can be shifted to others.

9. In respect of the regime for allocating the residual charge, the ENA is concerned that the removal of regional coincident peak demand (RCPD) may have unintended consequences of increasing demand for transmission services. This concern arises because loads and local generation that currently operate to avoid peaks may disappear quickly and Transpower may not be able to implement demand-response programmes or LRMC charges quickly enough to restore the current level of peak management. We strongly urge the Authority and Transpower to examine this issue before making final decisions, and/or that Transpower be given flexibility to continue to use an RCPD-based approach to recover residual costs.

10. We remind the Authority that ENA members are progressing work on future distribution pricing options. This work centres on an industry-led response to significant change which is already underway, due to technology and increased energy efficiency. The proposed TPM does not adequately address the strategic issues facing Transpower as owner and operator of a national grid facing substantial change. It is noted that the TPM is an allocation model, which feeds into distribution, but it is worth reminding the Authority that any pricing models should take into account the significant strategic issues facing the sector.

11. This submission reviews the Authority proposal in light of the perceived problems with the existing TPM. Transmission pricing is about allocating sunk costs which involves trade-offs. These involve judgements which are broader than just economic efficiency.

12. The ENA considers that Transpower is likely to have to make a significant number of judgement calls in implementing the proposed regime. To avoid Transpower becoming embroiled in lengthy

disputes and to provide it with some guidance for making decisions, the ENA submits that the Authority should include in the guidelines some decision-making criteria for Transpower to apply.

13. The ENA submits that the CBA appears to be poorly conceived, with assumptions made about retail pricing which are at odds with the intent of the proposal. For example, the CBA assumes that retail prices will change under the proposal so that peak demands will be more strongly signalled. However, given the AoB and residual charges are intended to be designed to be as unavoidable as possible, retail prices should be expected to be more fixed and transmission peaks should be expected to increase. The ENA submits that the CBA is therefore unreliable as the basis for the EA's proposals.

14. Specifically, ENA members submit that:

- Improvements can be made to regional coincident peak demand (RCPD) that would power/de-power the regional signals. Improvement would adjust the regional allocations of the interconnection pool to keep any regional peak signalling benefits that remain with the RCPD.
- If, as it appears, the Authority is now concerned that the current TPM lacks 'fairness' across the various regions (rather than its previous focus on dynamic efficiency), then there needs to be a conversation between the regulator and industry about the fairness issue. This TPM proposal does not fulfil either the efficiency or fairness role.
- The industry technical and demand changes that are underway will impact the durability of any TPM. It is better to deal with these uncertainties from a known TPM platform than one which introduces its own, likely material, set of unknowns.
- The Authority needs to ensure that it follows good regulatory practice – consistency and proportionality are especially important when building in flexibility through mechanisms like asset optimisation and what appears to be deemed beneficiaries. Optimisation is particularly troublesome and looks as if it will entrench poor price signalling.
- In the same manner, load and generation allocations need to be set on a 'principled' basis if they are to support this proposal. This proposal serves neither very well, with the bulk of revenue reallocation now with load on a seemingly arbitrary basis.
- Serious consideration should be given by the Authority and Transpower to including a long-run marginal cost (LRMC) component to effectively signal economic costs. This is a principle based matter rather than a tack-on as the Authority proposes with LRMC in the TPM proposal.

3. Proposal to change the TPM guidelines

15. The Authority has published an issues paper that proposes a change to the guidelines for transmission pricing. The Authority has previously suggested various changes to the TPM though there was general disapproval especially regards whether the proposed TPM mechanisms would deliver the claimed benefits and indeed be able to be implemented.

16. Compared to previous versions the changes proposed in this second issues paper are relatively simple. The Authority wants to do away with the current HVDC charge on South Island generators and replace it with a charge partly based on the benefits of grid users relative to specific transmission assets (an AoB charge). It also wants to replace the current interconnection charge with a postage stamp 'residual' charge. The AoB charge will be levied on both generators and load in proportion to assessed benefits from the specific assets, while the residual will be levied on load only in proportion to load 'capacity'. The definition of capacity is yet to be identified.

17. To provide some degree of flexibility to what appears to be simple but tightly defined TPM guidelines, the Authority proposes to expand the scope of the prudent discount policy arrangements. This change will give Transpower considerable discretion to agree to discounts when customer disconnection from the grid as a result of transmission charges is a real possibility or where local generation is a more cost effective solution than grid connected generation.

18. The Authority also proposes to allow for some flexibility with the AoB charge by introducing 'asset optimisation', where a material change in circumstances alters the assessed benefits to the grid users paying the AoB charge. Where optimisation reduces an AoB charge the amount of the reduction falls into the residual for recovery from all other load customers.

3.1 Principles for transmission pricing

19. Rather than be guided by a decision making framework that gives rise to transmission pricing proposals that promote disagreement, the ENA believes that guidance from a more accepted set of network pricing principles would deliver better outcomes.

20. The ENA has a project team preparing a consultation paper on what future distribution prices could look like. The work includes detailed consideration of implementation matters and possible paths to transition from the pricing we currently have to a future where pricing is better related to network costs and the services that are provided from the network. While the work is still in progress, it is worth citing the following extract from the paper that describes what future pricing needs to look like.

Key features of future pricing are that it is:

- *Actionable – can be readily adopted by retailers and customers, is implementable and accurate*

- *Compliant – meets regulatory requirements*
- *Cost reflective – fair pricing that is free of inefficiencies and cross subsidies*
- *Durable – independent of market, technology and policy changes*
- *Service-based – reflects the services being provided*
- *Simple – transparent and easy to understand*
- *Stable and predictable – avoid volatility*

These objectives translate into the following three outcomes for stakeholders:

- *For consumers: fair pricing*
- *For retailers: fit-for-purpose pricing*
- *For networks: durable and cost-reflective pricing*

Prioritising a particular outcome over another will vary across distributors because of the unique characteristics of each EDB network environment. Consumer groups vary across regions as does both the geography and network layouts.

21. The ENA considers that features or principles such as these provide better guidance when thinking about transmission pricing than the decision making framework (DME) that the Authority describes in the issues paper. The ENA remains of the view that the Authority misuses the framework and deems particular approaches to allocating Transpower revenues as being more or less market like when they are in reality all administrative solutions.

22. Because transmission charges to EDBs will largely be assessed against these desired outcomes, the same principled approach should be adopted by the Authority and Transpower when thinking about improvements to the TPM. Such an approach will avoid the need to debate whether a particular transmission pricing method is more or less market like, when it can be scored against the features/principles that we set out here.

3.2 Electricity Authority's strategic intent

23. The ENA questions whether the Authority is heading in the right direction with this proposal when considering an approach based on pricing principles such as these. There have been quite a number of directional changes for proposals to change the TPM over an extended time period and we regard this issues paper as another twist in the path. We are left concerned about its durability.

24. We see a number of issues that could make this proposal unworkable in the following ways:

    - The balance between prescription and flexibility is still not right. Other than the tightly specified AoB charge, we believe that there is too much flexibility in this proposal and there is significant risk of inefficient, wealth reducing and unintended outcomes. It is unlikely to be service based and the inefficiencies generated in downstream areas could well outweigh the inefficiencies that are claimed to result from the existing TPM.
    - Better, more detailed (though not too much) guidance to Transpower is needed to allow them to initially identify whether the proposal is indeed principle based and better than

the status quo. Despite the presence of a CBA in the paper, without guiding principles it is impossible to see whether this proposal will result in a better outcome.

- The Authority is passing some of the discretion for design and implementation of the TPM to Transpower, which will possess significant negotiating power when dealing with grid users. There are limited incentives on, and guidance for, how Transpower interprets and responds to this discretion.
- The ENA is especially concerned at the expanded scope that Transpower has when considering the extended prudent discount process (PDP). For ENA members, this raises questions around: what specific disciplines will be on Transpower to provide discounts; the benefits of the scheme versus the resource requirements; and the transaction costs that will likely accompany this process. It is very important that the scope Transpower has with PDPs is principle based because when a PDP application is granted the transmission charges that are displaced fall on load and increase the residual.
- It is difficult to judge the strategic effects of the proposal. We question whether it will deliver an outcome that will be seen as more efficient and equitable, in terms that grid users each pay a fair share. The Authority's analysis and financial trickle down of the TPM proposal include only one year of market data, and are heavily caveated as indicative only. They do however see mass market load allocation of Transpower revenue rise from 72% to 80%.
- This is of concern when thinking about the size and nature of the wealth transfers that result from the proposal and the possible real economic responses by participants to these transfers. It is also unhelpful that the analysis is not conducted at EDB and/or grid exit point (GXP) level so that a more granular assessment can be made to identify possible outcomes

3.3 In - principle approach?

25. The ENA has concerns that there are now material inconsistencies between previous Authority proposals and this one. Examples of this inconsistency:
    - Promoting peak pricing for distribution networks but removing peak pricing signals for transmission.
    - Replacement cost for new assets (to reflect "service based pricing") and then depreciated historical cost for existing assets (for administrative ease).
    - Reviewing the TPM to deliver efficiency but making changes to deliver fairness (and compromising efficiency in the process).
26. In earlier consultations the Authority identified its priority as efficiency. However it now talks about aspects of fairness as guiding its thinking about whether the TPM has implications for inefficiencies (for example, South Island electricity consumers paying for North Island upgrades).

27. While the paper makes reference to how the Authority is applying its decision making framework (DME), the issues paper has replaced the previous DME language with ‘services’ and ‘cost reflectivity’ language that are common with distribution pricing. We question whether this is transmission language given that it is difficult to identify specific services provided by the grid, there are no ‘price’ signals in a conventional sense, and nearly two thirds of the revenue to be recovered by the TPM is ‘residual’ which is by definition, not cost reflective. In addition, the Authority’s discussion of service-based pricing for distributors consistently refers to customers having “choice” when service-based prices are adopted. The notion of “choice” seems to be omitted in the discussion of the TPM without any supporting rationale.

28. Despite the presence of the DME we read in the paper that the Authority is wanting to, in some way, connect the TPM structure to a more principled structure that is applied to distribution pricing, such as we set out above. We have concerns with this approach for several reasons:

    - The Authority has no ‘pricing principles’ attached to the TPM, just a hierarchy of preferred allocation approaches in the DME (arguably they are all administrative to some degree),
    - Various objectives and/or principles that are applied to distribution pricing involve trade-offs depending on the network, customer groups, location, etc. Transmission charges have been determined from an assessment of which approach is the least inefficient. These do not seem to be compatible methodologies.
    - Full cost reflectivity is by definition not possible, so costs are allocated - in one form or another - to grid connections. For the ENA the question therefore is whether partly replacing current HVDC charges with an AoB charge is a better (or a less worse) allocation device than the current allocation mechanisms. From our preliminary assessment we are inclined to think it is not better.

29. A principled approach to the TPM is essential for durability, especially when thinking about the increasing levels of uncertainty that are emerging, driven by changing consumer preferences and technology options in distribution networks. Here we think that technology changes in distribution networks have the potential to affect electricity consumption patterns which in turn will change the share of the TPM charges that distributors face over time and further increase uncertainty going forward, impacting TPM durability. At least with the current TPM, the uncertainties can be dealt with from a known TPM platform.

30. A mechanism for allocating Transpower operating costs and overheads is also important to EDBs – both directly as part of the TPM and as it relates to distribution pricing. The total sum to be allocated here is not trivial and will have an impact on EDBs, depending on how it is allocated. The allocation methodology also impacts how EDBs will handle these costs so the approach needs to be principles based and efficient, in a similar way to the approach distribution networks are taking with their own pricing.

3.4 TPM and regulatory practice

31. A commonly referenced set of good regulatory practices are those defined by the ‘UK Better Regulation Task Force’ as:

- Proportionality
- Accountability
- Consistency
- Transparency
- Targeting

32. The ENA has concerns that the Authority has not applied the same critical standards to both the process it is following, and to its proposal, as it had done when evaluating the status quo and other options. For example, the Authority wants to remove the RCPD charge because it believes that some parties 'avoid' it. RCPD is a targeted peak usage charge reflecting one of the cost drivers in the grid, which is a good thing. The RCPD charge is to be replaced in part by a 'residual' and an AoB charge, neither of which are especially cost reflective or service based if they are charged as the Authority propose on the capacity at the ICP.

33. ENA members also see proportionality as a problem – the Authority wants to reallocate the HVDC charge away from South Island generators (via an AoB charge) based on its estimate of inefficiencies of about $12m NPV under the current arrangements. We estimate that this approach results in wealth transfers of up to $650m NPV (an ENA estimate) that will likely generate their own set of unwanted, efficiency impacting, outcomes and costs.

34. The proposed charging structure has the potential to compromise consistency over time. For example the AoB charge is made on the basis of assessed or 'deemed' beneficiaries from the transmission assets which will likely change going forward. The proposal is that these changes will be accommodated through the 'material change in circumstances' provision in the proposed TPM where the displaced AoB charges can be moved to the residual. This may be a simple and convenient approach but it will dilute the already small 'services-based' and 'cost-reflective' signals that will remain in the AoB charges.

35. In summary the ENA see a high risk of adverse impacts in the short to medium term - outcomes that the Authority may not have considered. But there is potential for stability in the medium term once parties understand how the TPM mechanisms that Transpower develops work in practice. The potential size of the costs of these short to medium term adjustments are of considerable concern to the ENA.

3.5 Durability

36. The ENA believes that the proposed TPM will be less durable than the status quo. In particular, an expanded prudent discount policy (PDP) approach on a yet-to-be-determined basis will likely become a big impost on Transpower. This will incur non-trivial transaction costs, especially given the work that is necessary when examining applications for discounts. We are of the view that the broad scope for negotiating a discount is not a good recipe for a durable TPM and it should, at a minimum, have more structure than is proposed. It may well be that the responsibility for evaluating the costs and benefits of prudent discounts should be with a party other than Transpower, likely independent from the electricity industry.

37. We believe that durability will also be threatened by the opportunity offered to parties to 'game' the AoB and residual charging pools. The residual pool starts at about $500m and can be added to if and when parties which incur AoB charges apply to have assets 'optimised' out of the AoB pool and into the residual pool. This opportunity depends on a material change in circumstances to load or generation that is subject to the AoB charge and appears to be a matter that is negotiated with Transpower. Transparency of process and decisions may help reduce this risk but will not eliminate problems arising. Otherwise, over time the new TPM would look more like the existing TPM but with a huge residual.

38. The ENA notes that Transpower's revenue is guaranteed and that transmission charges likely end up being paid by consumers regardless of the TPM.[1] The structure of the TPM is therefore about allocating costs in a way that discourages inefficient behaviour as charges make their way through the supply chain. The principles on which load and generation are charged differently is unclear and will likely give rise to issues that have a greater impact on durability than the current TPM. The rationale for charging load 100% of the residual pool should be reconsidered for this reason.

39. Transaction costs for both Transpower and grid users to implement and administer the TPM are likely to be material, rather than smaller, as the Authority suggests. It appears to the ENA that, faced with unknown but likely material costs and uncertainties regarding outcomes from the change, Transpower and grid users have few incentives to support the proposal either now or as it is implemented. This is further compounded by the extended period for Transpower to develop TPM, consult and implement.

3.6 Specific design issues

Other areas of concern are:

CBA benefits

40. The quality of the CBA has the potential to undermine the proposal. If there is significant doubt about the benefits ($200m+ NPV) that have been assessed by Oakley Greenwood.

    The ENA has concerns with aspects of Oakley Greenwood's (OG) assessment. It has quoted benefits from prospective investments in generation, estimated at $93m NPV. These will be realised because investors will better see the costs of transmission under the new TPM when they appraise business cases. The CBA treats sunk costs as sunk however and they do not matter. In theory this is correct – AoB and connection costs could well be better signals of grid costs than the current TPM (but could be materially improved if a LRMC charge is also included).

    However, for this benefit to be realised OG state that the quantum of this benefit relies on four assumptions in their CBA actually happening together – that is, they converge:

    - There has to be *material amount of generation required* over the next 20 years,

[1] We also see no valid reason from excluding generators from contributing to the residual charge in the TPM proposal. The Authority's suggestion that the "residual charge" would flow through the competitive wholesale electricity market offers sets aside the fact that most generators make offers to be dispatched based on their marginal cost of dispatch which typically is exclusive of fixed costs – unless the market lacks sufficient competition.

- The grid *needs to be expanded* from current capacity to meet this new generation,
- Costs to expand the grid *need to be materially different across the regions*, and
- Costs to build *different types of generation need to be similar.*

41. If these factors do not converge, then the prospect of seeing material benefits from improvement to the location, timing and sizing of new generation will decay. Because of this risky (some might say improbable!) convergence, and because it drives nearly half of the overall benefits, the ENA prefers to see a probability attached to the NPV estimate of this benefit. At a minimum this revision will signal the likelihood of any benefits from the convergence of assumptions but would give a sense of materiality.

42. In a similar fashion, the ENA has concerns about the quantum of the CBA benefits ($90m NPV) that are realised by removing the RCPD signal from the interconnection charge when recovering sunk costs. The bulk of this benefit is realised from the lower probability of (larger grid connected) customers disconnecting from the transmission grid under the proposed TPM because their new charges would be less than under the existing TPM. The difference in charges is counted as a "producers' surplus" benefit to the customer and can be supplemented with a PDP as required. It appears that it is a transfer to consumers with no net benefit.

43. The situation described in paragraph 28 is in theory a reasonable approach but the reality is that there are many factors that currently persuade customers to use local rather than grid generation, the RCPD charge being but one. Classing the difference as producer surplus and therefore a quantifiable benefit is too simplistic. The difference is simply a cost that is recovered from other consumers who are currently not being charged, and the opposite effect (dis-benefits) may well be the outcome.

Removal of RCPD

44. Doing away with the RCPD will have an impact on peak grid demands in different regions. While peaks are unlikely to reduce, it is unclear what the grid impacts (and costs) will be. This is partly an empirical issue (if data on load control/RCPD avoidance were available) but regardless, it is likely that peaks will increase with poor economic pricing signals to direct load behaviour. This would result in spare capacity gradually being eroded to the point where more investment is needed much earlier than under the RCPD approach.

45. The other matter of concern with removing the current RCPD charge is whether nodal pricing is of itself an adequate locational signal of grid congestion to the market, or whether RCPD does in fact have a regional peak signalling benefit and should be retained. To some extent this may also depend on how an AoB charge is implemented and how the whole market/transmission system evolves under a new TPM. This will likely remain a material uncertainty.

Long run marginal cost

46. The ENA believes that economic investment signals are essential for grid investments going forward and it supports the Authority's consideration of inclusion of a LRMC charge, but not an

add-on the Authority propose. Rather the charge needs to be well constructed to signal locational economic costs and be a core element of the TPM. It is important to differentiate and deal with past investments using allocation mechanisms. However it's also important to provide economic price signals and guide future investment.

Evidence

47. The ENA considers that an evidence base is missing from the proposal, which is sometimes quite theoretical. For instance, without particular supporting evidence, the Authority cites the example of a petition to underground lines in Auckland as an investment decision that may have proceeded under the current TPM, but would not under the proposed AoB charging approach.

Modelling AoB charges

48. The modelling results in the issues paper describe benefits that are far in excess of the proposed annual AoB charges (Figure 38 in the paper). If this is correct, it indicates to the ENA that the investments that were modelled (NIGU, Pole 3, etc) were in no way 'bad decisions' as has sometimes been suggested. More importantly it suggests that, even under the proposed TPM, parties that benefit will probably continue to inefficiently over-support any investment. We also note that there is no evidence in the CBA that better investment decisions will follow as a result of this proposal.

Residual

49. The ENA believes that technical change over time in transmission and distribution networks that we refer to above, as well as entry/exit of generation and load, could impact on the proposed optimisation mechanism. Changes such as these come under the 'material changes to circumstances' classification that the Authority proposes as the optimisation trigger and, in the view of ENA members, this would result in a residual that would likely grow over time. This is in contrast to the Authority view that there will be a migration of new assets into the AoB classification and that the residual will reduce.
50. If the ENA is correct in the view raised in paragraph 40 above, the durability of the Commerce Commission's price regulation approach, as it applies to capex, could be called into question. (That is, moving the 'optimisation' shortfall from AoB to the residual and directly onto consumers will be very unpopular, which will erode durability). The risks here falls onto distributors who likely end up with most of the residual over time.

3.7 Conclusion

51. The basis on which the Authority has built the components of the proposal does not stack up for ENA members owing to its lack of a principled foundation such as those proposed to guide the development of future distribution pricing. A principled foundation is also important to improve the

way that the TPM interacts with DG and especially to enable distributed generators to assess their DG investments as alternatives to transmission investment. This is not possible under the current nor the proposed TPM's.

52. Given ENA members concerns with this proposal and with the process that the Authority has followed that are reflected in this submission, the ENA submits that the Authority should allow interested parties the opportunity to review all submissions through a cross submission process. A cross submission process would also allow parties to understand Transpower's views on the proposed TPM which are important because they will, in reality, shape how this proposal is developed and implemented.

4. Authority questions

53. The Authority has asked 4 specific questions in the issues paper, all of which relate to the guidelines to Transpower – section 7 of the paper.

> *Question 1: What threshold value should be used to determine which new investments should be subject to the standard area-of-benefit charge versus the simplified area-of-benefit charge? Please provide your reasoning and evidence in regard to the trade-offs mentioned above and any other factors you believe are material to this decision.*

54. ENA members do not support the AoB charge in any form because it is a discretionary allocation of sunk costs rather than a structured price reflects the service being provided and the costs associated with that service. The issues paper promotes it as a service based charge for the interconnection grid (p94) and cites a range of benefits that we do not believe will eventuate. It is an allocation mechanism that has no impact on future investment. For new, future investments however, beneficiaries of those investments should be identified in the business case and charged accordingly. There is no need to apply a threshold to the investment size.

> *Question 2: Bearing in mind that it is proposed that Transpower develop a method of determining the areas of benefit, which of the above methods do you think should be used to determine the areas of benefit from high value investments in the interconnected grid?*

55. It is impossible to answer this question. The Authority has been grappling with this question for many years and it is unreasonable to ask submitters to objectively evaluate complex cost allocation mechanisms for a transmission grid in 10 weeks.

> *Question 3: Bearing in mind that it is proposed that Transpower develop a method for determining the areas of benefit, which of the above methods do you think should be used to determine the areas of benefit from low value investments in the interconnected grid?*

56. It is also impossible to answer this question for the same reason that we cite in para 46 above.

> *Question 4: Do you prefer the residual-based approach or the surcharge-based approach or some variant of the two and why?*

57. ENA members do not have a preference in this matter. Transpower overheads are material and should not be allocated to grid users on a random basis. The approach to allocation of Transpower's overheads should be principle based and fit with the overall package of charges that make up the TPM. The two allocation methods cited on page 123 could be added to in the same way that other allocation methods could be developed for current HVDC and interconnection costs. The Authority needs to be clear about objectives and outcomes and the principles it will apply to grid charging.

5. Appendix

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
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