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Submissions
Electricity Authority
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*by email: submissions@ea.govt.nz*

**SUBMISSION ON TPM OPTIONS**

1 Orion New Zealand Limited (**Orion**) welcomes the opportunity to comment on the "Transmission Pricing methodology: TPM options" working paper (the **paper**) released by the Electricity Authority (Authority) in June 2015.

2 The Electricity Networks Association has also submitted on the paper. Orion endorses the ENA submission.

3 We consider that the paper indicates a significant movement in approach when compared with the October 2012 proposal.

4 However we still have some major concerns in the following areas:

- Problem definition,
- Investment decision-making,
- Cost allocation versus pricing, and
- The decision-making and economic framework.

5 Together our concerns lead us to maintain our previous advice that the Authority's TPM project should be abandoned.

6 The remainder of our submission expands on the reasons for our concerns, and also discusses some of the material technical issues we see with some of the options.

**Problem definition**

7 In our view the problem definition discussion is short on empirical information. Some of this is discussed below under investment, but one specific example is discussed here.

8 The first part of section 4 of the paper is primarily focussed on the increase in the interconnection rate consequent on the significant transmission investment programme in recent years. It is a perfectly respectable hypothesis that the increase in the interconnection rate, under RCPD, might encourage increased and / or

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inefficient avoidance of grid usage. However, it is only a hypothesis. Have participants changed their behaviours and increased avoidance of grid usage as the rate has increased? Which participants and using what technologies? The paper does not tell us.

9 We do not know much about demand response in other parts of the country, but we do know a lot about it in the upper South Island. We can confirm that our approach to load management has not materially changed as the interconnection rate has increased, and nor has there been any material change in the level of demand response.

10 If there has been increased response in other areas, then the efficiency consequences of that also depend on the cost of it: the cheaper the response, the less inefficient it is to use it. The paper does not tell us what the cost is.

11 Even if there has been inefficient demand response, there is the question as to the most efficient regulatory response. Transpower has recently proposed an increase to the "N" used for RCPD to depower the price signal. This may well achieve a resolution of the problem at little cost within the existing TPM, and if so there would be no further benefit in changing the TPM to address the same issue.

**Investment**

12 All investment decisions by any business can turn out to be bad[1], for all sorts of reasons. Central to the rationale for the proposed changes to the TPM is that investment decision-making can be improved. However, it remains unclear from the latest and previous papers which transmission investments were bad, and how bad they were.

13 Over the course of the consultation so far, the Authority has presented analysis of private benefits, as calculated by the SPD method, of a number of significant transmission investments. The following table shows the ratio of calculated uncapped benefit to cost for several major projects:

| Investment[2] | Benefit to cost ratio, % |
|---|---:|
| Pole 3 | 358% |
| Pole 2 | 3,230% |
| Wairakei ring | 2,702% |
| BPE-HAY | 75% |
| NIGU | At least 100% |
| NAAN | At least 50% |

[1] Or be unexpectedly good.

[2] The first four are from the paper, Figure 18, p117. NIGU and NAAN values are from the Authority's January 2014 "Transmission pricing methodology review: Beneficiaries-pay options" working paper, Figure 6, p 36, which shows benefits for various capping levels, and the 4 month capping values have been used here. The uncapped values must be at least as high, and are probably higher.

14 Purely private benefits do not give the full picture of the value of transmission investments, in particular reliability investments. But surely if private benefits alone usually exceed costs, and often by significant margins, then the investments cannot be bad ones? There might perhaps have been better investments that were not made, but that is a much weaker argument.

15 Even if we accept that New Zealand has been making poor decisions about transmission investment, we need to understand why. Unless we do, we cannot have confidence that changing the TPM will improve the decisions. The obvious place to start is with a single bad decision, and then thoroughly review the decision-making process around it. This would help identify where the process went wrong, and, if the problem was an information one, may identify the crucial missing information, why it was not presented, and who did not present it. We could then look at other poor decisions to see if common themes emerge.

16 As it stands, the Authority appears to be simply assuming that some parties do not participate fully and openly in the process because they will not pay enough of the consequent cost, and that if they pay more, they will. Furthermore, the improved participation is assumed to lead to better decisions. That is a long bow to draw. As we understand them, the investment criteria are economic –"What is best for New Zealand?" Participants' private commercial perspectives may be relevant, but they are not necessarily determinative. We have a regulated decision-making process because New Zealand has decided that relying on private commercial arrangements and incentives will not deliver the best economic outcome.[3] This suggests that better revelation of private commercial information is no guarantee of better decisions.

17 The argument must also mean that those who will pay too much under postage stamp pricing are over-incentivised to oppose an investment. Again, have we seen this behaviour, and what was the result?

**Tilted postage stamp**

18 The essence of each of the options (at least under implementation approach A) is that charges are reallocated around the country, effectively by a more geographic targeting of cost. This looks to us like it could be achieved by a relatively minor change to the existing TPM around how Transpower's interconnection cost allocation is carried out – there would be a separate allocation of cost to the various regions, rather than an allocation of the total cost across all regions. As a general rule, regulatory change should only be to the extent necessary to address the problem. While we remain unconvinced that this reallocation of cost will yield net benefits, the Authority could, as an alternative, consider tilted postage stamp as a simpler option to achieve such reallocation if that remains an objective in the final proposal.

**Cost allocation and pricing**

19 In our view, much of the analysis from the start of the TPM review has confused cost allocation and pricing. Cost allocation is an important step in the process, but it is

[3] A decision which may itself be wrong, but if it is, changing the TPM is a very indirect approach to correction.

important to understand the wider pricing strategy which gives the allocation context: we need to know what the costs are being allocated for before we get busy.

20 One fundamental thing that needs to be decided before we start allocating costs is: are we providing access to particular assets, or are we providing a service? We believe that the interconnection component of the existing TPM is a service – a single system into which parties can inject at many points, and offtake at many points, and with a particular security standard. As with many services (for example bus fleets or airlines[4]), it can be provided by assets of various ages and quality without the price paid differing - a new bus might be brought on to travel a particular route, but that does not necessarily mean it will have higher fares.

21 Pushing this analogy further, and perhaps too far, we note that bus fares often vary according to distance travelled, although often in a fairly simplified way - say three zones for a large city. But the transmission system is an unusual bus in that, when one gets on, the destination is not known, and it may be very different depending on the time of travel, or how much it has rained in the previous 3 months. To be sure some journeys are more likely than others, but the fact that many different journeys are possible has value, and passengers may be happy, in an environment of uncertainty, to buy a pass that allows them to travel on any of the routes.

22 Thought about in this way, postage stamp pricing for access to a service provided using assets at various stages of the lifecycle is at least plausible, and this supports cost allocation across the interconnected grid. Tilted postage stamp is a variant that essentially recognises that some groups of passengers may have different needs and are happy with a restricted pass.

23 We are not suggesting this as a solution, we are merely trying to show that the way the system is conceived informs the consideration of the solution. We believe the Authority is conceiving of the transmission system as a set of dedicated assets and the TPM is about finding the right lessee. In doing so it has in our view overstated the problems with the current TPM, and locked itself into thinking that payments more closely related to identifiable specific assets are necessarily superior.

24 A service-based approach also allows consideration of various dimensions of the service. We note for example that some of the thinking around emerging technologies conceives of the grid as providing back up as one component of the total service. A TPM that seeks to allocate cost based on physical assets likely makes it harder to price service components in this way.

25 More broadly, while cost allocation helps with an understanding of the components of revenue to be recovered, there is no need, in our view, to link it so specifically to prices. The nature of transmission networks, and indeed natural monopoly generally, is that efficient prices are usually insufficient to recover costs, and there will be some need to recover the residual. But it isn't necessary to restrict the revenue recovered from the efficient component (which might be linked to some notion of LRMC, or economic benefit) to some allocation of accounting cost.

[4] Or indeed, postage!

## Decision-making and economic framework

26 We do not believe that the framework provides useful guidance, and the paper provides further examples that illustrates this.

27 For example, the proposed deeper connection charge is described as "market-like", and therefore is highly favoured by the framework. This is based on the idea that parties could band together to separately contract with Transpower to build some of the assets that form part of the current interconnected grid, or even build and own the assets themselves. But this strikes us as more incantation than economics. The actual ability to do this in practice is we believe severely restricted. The Authority put it well in its October 2012 paper[5]:

> **Assessment of suitability of a long-term contract option to recover HVDC and interconnection costs**
>
> 6.3.9 Long-term contracts without an effective multilateral decision-making process are not considered a viable option for recovering the costs of HVDC and interconnection assets, relative to the status quo and the Authority's proposal for three main reasons. First, the number of counterparties involved will make the transaction costs too high. Second, the potential for parties to "hold out" from agreement or free ride, or both, on other parties' investment decisions would frustrate and impede investment and cost recovery. Third, there will be uncertainty about the durability of contracts in the face of technological or organisational change.

28 The Authority is wrong to suggest that deeper connection is market-like; it is instead a re-representation of a historical administrative arrangement, and is therefore at the bottom of the framework hierarchy.

29 There must also be considerable doubt as to whether it would be efficient even if it was possible going forward – natural monopolies are natural for the reason that most networks are more efficient if owned and managed as single entities.

30 Another example is SPD beneficiaries-pay. This method, which uses wholesale market data and allocates costs to actual beneficiaries, is now an optional add-on, when it appears to be superior (or at least not obviously inferior) in the framework to the new core AoB component which, as we understand it, deems who the beneficiaries are based on the parties identified in investment approvals.

31 To the extent that the capping of SPD benefits increases cost to be recovered via the residual, which is further down the hierarchy, it is inconsistent with the framework.

## Comments on key aspects of the options

### *– Deeper connection*

32 As noted above, deeper connection charging seems to be based on the idea that private commercial contracting for transmission assets is inherently superior to administrative decision-making. We disagree that this is private commercial

[5] "Transmission pricing methodology review - issues and proposal consultation paper" October 2012, page 128.

contracting as normally conceived, and we do not believe that it will lead to workable let alone superior outcomes in any case.

33 This is not to say that there cannot potentially be issues with the interconnection/connection boundary, only that any response should be based on specific examples and issues, rather than assumed superiority of one approach over another and the somewhat arbitrary application of a concentration index.

34 To assist the Authority in understanding the implications of deeper connection, we next describe an actual situation based on the identified deeper connection assets that the method allocates to Orion under HHI = 5,000: the Ashburton to Bromley lines.

35 The two Ashburton to Bromley lines form part of four 220kV circuits to supply approximately 1000MW of load into the upper South Island. These lines work collectively together to ensure that a fault on any line will not cause a loss of 1000MW of load in the upper South Island.

36 So two lines that are classified as deeper connection due to normal grid power flows are actually required to supply wider upper South Island load under contingency. Given that future upgrade investment decisions in the upper South Island will be directly linked to the capability of the grid to deliver under contingency, this deeper connection classification seems counter intuitive.

37 This concept is true in almost all parts of the grid – it is almost always true that investment is driven by the various post contingency states of the power system, not the normal state.

38 We also caution the value of an allocation methodology that discourages mergers of distribution network businesses. If the upper South Island was only two distribution network businesses then the entire upper South Island grid would be classified as deeper connection. This would not result in a change to the investment decision making process or outcome yet it would inappropriately load costs onto larger electricity distribution businesses who achieve efficiency through scale.

39 We also suggest that the Authority does some modelling which compares results of allocating cost using an HHI threshold of zero with those of allocating as much cost as possible on an AoB basis. We suspect there is little difference overall.

40 In applying the method, the Authority has calculated HHIs based on the parties that are the existing users: generators and distributors. Not only does this seem prone to gaming by those counterparties, it seems unstable in the longer term and may also constrain otherwise commercially sensible activity. It also equates distributors with load, when load could just as easily be conceived as being retailers or even end consumers, in which case we suspect the HHIs rapidly decrease below the threshold.

41 One of the Authority's external advisors on the spot market review came up with a useful way to delineate core grid assets based on the answer to the question: Who manages constraints? In the context of nodal pricing and associated complexity this was the system operator across a grid where the physical attributes and constraints are known, but which are otherwise open-access. This approach may not work so well or at all in a situation where there are additional commercial constraints imposed by the owner/providers of particular transmission circuits.

***– Area of benefit***

42 This strikes us as an unnecessarily complicated way to allocate cost based on use by linking it to benefits considered in the investment approval process. It would be interesting to know how those benefits were determined, as allocation on a consistent basis would seem appropriate. But even then we can imagine that there may at least be some contest as to whether those benefits were correctly assessed and/or have actually materialised. Since transmission investments often disadvantage parties, we presume such parties would get a credit?

***– SPD beneficiaries-pay***

43 SPD beneficiaries–pay was the key innovation in the October 2012 paper, and the aspect most clearly linked to the improved computing power leg of the material change in circumstances argument. It is interesting then that its star has fallen so far that it now just an optional add-on. The paper does not in our view adequately explain the fall. An explanation would help us judge whether the replacement approaches have the same problems.

44 We take the view that, in the context of the new options, SPD is probably not worth the trouble of adding it on. However, we previously submitted that it could perhaps be used to inform cost allocation to broad groups, and in particular to establish some broad and perhaps even durable recognition of where economic benefit of the grid falls, particularly with respect to key components like the HVDC. It might also help with establishing allocation of the cost of reliability investments, and appropriate allocations of cost between generation and load. This is another example of confusing cost allocation with pricing.

***– Residual***

45 In the October 2012 proposal, the residual was split 50:50 between generation and load, a split that had no compelling rationale. The latest paper suggests that all of the residual be allocated to load, with the rationale being one about not wanting to upset allocative efficiency in the wholesale market. We submit these are two different points: if it is appropriate to allocate cost to generators, then consideration can be given to the least distortionary method (which based on other aspect of the options appears to be on a per MWh basis).

46 But no matter where the cost falls, it will probably end up with consumers. Allocative efficiency then needs to be assessed in an aggregate sense based on retail prices, not with respect to one component – the wholesale price. While generators have only the energy price to recover costs from, they may not always be able to fully recover this, and so it might be that they tend to price this in more when prices are high, and there is at least some chance that this coincides with periods of high demand which might themselves be periods when willingness to pay is highest. There is also no reason to believe that distributors in their own rebundling of transmission cost will not variabilise such costs, at least partly to comply with regulation!

47 On this last point, we note that the base option involves recovering around $500 million per year (combined AoB and residual) based on this notion of capacity. The rate works out at around $10 per kW per year, or $200 for a typical category 1

metered connection with one meter.[6] As the Authority is aware, the maximum annual distributor fixed charge for compliance with the low fixed charge regulations is $55 per year, so $145 of the capacity cost would have to be variabilised, for probably around half of the category 1 connections. This rather undermines the objective of pricing in such a way that there is no incentive to avoid use of the grid. At the very least this suggests to us that any move to such a form of transmission pricing be accompanied by repeal of the low-fixed-charge regulations.

48 As we have previously submitted, we consider that load should bear a disproportionate share of the cost of reliability investments, since we have no doubt that load benefits more than generation from such investments. This might be close enough to 100%, but it would be good to see some stronger evidence. (And as noted above, SPD might help?)

49 Both AoB and the Residual envisage actual charges for load being based on capacity. The Authority will already be aware that its approach to capacity includes an unacceptable reward for and very large bias (by allocating only about one sixth of the appropriate cost) to direct grid connection for larger customers because of the inconsistent approach to measurement, and likely but lower magnitude misallocation among distributors because of the way capacity is, oddly, linked to the number of meters. While using AMD for all customers might include a bias towards embedding, this will depend on the distributor's response, and so is less likely to be a concern. But we believe ADMD is a much more consistent way to measure shares of cost for a transmission system that fundamentally, from a load perspective, must be built to support ADMD. RCPD is one version of this, but if there are real issues with creating incentives for inefficient avoidance, regional shares of total NZ CPD could be used.

***– Application and transition***

50 We agree with the sentiment behind application B that it is not appropriate to surprise participants with a cost allocation linked to past investments they might not have wanted, and which significantly change the geographic and counterparty allocation of cost. However application B has the implication that, for example, upper South Island consumers could end up paying for both past upgrades in other areas, and future upgrades locally. We propose that, at the very least, as new investments are completed the allocation of cost is revisited so that over time the TPM does not lock in this double-dipping feature. Put simply, application B needs transition arrangements just as would application A.

[6] And many such connections have two meters, which would double the cost, even though in most cases the number of meters tells us nothing about the actual capacity of the connection.

## Concluding remarks

51 Thank you for the opportunity to make this submission. Orion does not consider that any part of this submission is confidential. If you have any questions please contact Bruce Rogers (Pricing Manager), DDI 03 363 9870, email bruce.rogers@oriongroup.co.nz.

Yours sincerely

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