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Submissions
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SUBMISSION ON PROPOSED CHANGES TO THE TRANSMISSION PRICING METHODOLOGY

1 Orion New Zealand Limited (**Orion**) welcomes the opportunity to comment on the "Transmission Pricing methodology: issues and proposals" consultation paper (the **paper**) released by the Authority in October 2012.

Introduction

2 The Gordian knot of transmission pricing has challenged the industry for many years. The paper does not, in our view, provide a means to untie it. In some ways the proposal creates even more of a tangle - there is much in the proposal that we find it difficult to fully understand.

Summary and recommendations

3 In Orion's view the paper **does not**:

- Clearly establish the general case for change with respect to interconnection charges
- Establish the specific case for moving to dynamic, SPD generated benefits-based charges for key interconnection assets, and in particular does not explain how this will lead to better investment decision-making
- Provide any robust basis for the 50:50 split of the residual component between load and generation

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- Adequately address the regulatory implications of the proposal, specifically with respect to:

  (a) the links to the regulation of Transpower and in particular its major investments

  (b) the impact on distributors with respect to price path compliance.

- Reflect an adequately detailed understanding of the current TPM and how charges flow through to consumers

- Properly consider the end-consumer cost incidence of the changes

- Adequately consider how to transition to the new arrangements.

4 We acknowledge that the paper:

- Correctly identifies that charging for the HVDC is the key controversial component of the current TPM

- Proposes sensible changes regarding reactive support charges

- Rightly proposes no major changes to the non-interconnection elements of the current TPM.

5 Orion recommends that the Authority:

- Abandons the interconnection charge component of the proposal as it stands

- Further develops the idea of beneficiaries-pay, but in a longer term context where it:

  (a) attempts to establish reasonably enduring and stable cost allocations for interconnection assets, perhaps with regular updates

  (b) clearly links the grid new-investment decision-making process to the assessment of benefits

- In the light of that, revisits its thinking on who the counterparties for transmission charges should be

- Produces a new consultation document reflecting the different approach.

6 The remainder of our submission is in two parts:

- Comments on key aspects of the paper, and

- Responses to the paper's specific questions as an appendix.

7 The Electricity Networks Association (ENA) has also submitted on the proposal. Orion supports the ENA submission.

Comments on key aspects of the paper

8 This part of our submission focuses on the following aspects of the proposal, which primarily relate to interconnection:

- The nature of the consultation process
- The meaningfulness of the benefits-based approach
- The stability of resulting cost allocations
- Allocation of the residual
- The practicality of the associated billing process
- Consistency with the grid investment evaluation process
- Consistency in the treatments of LCE
- Regulatory and other considerations for distributors
- Possible unintended consequences

The nature of the consultation process

9 In our view the Authority has not followed a good process in consulting on such a major change. In particular we are concerned that the amount of material that has been produced *after* the release of the initial paper makes it very difficult to know quite how that material relates to the proposal, and what the final case for the proposal is. We therefore do not believe that the resulting consultation is satisfactory.

10 We believe some form of advisory group would have been able to help the Authority work up the proposal so that it was in a much better state on release.

The meaningfulness of the SPD benefits-based approach

11 There is at least a superficial attractiveness in seeking to assess the private benefits of various components of the transmission system, and beneath that the conceptual idea of using changes in values of consumer and producer surplus that result from “removing” transmission components between SPD solves.

12 However, the approach raises a number of issues.

13 Firstly, if we have interpreted para 5.6.15 correctly, the benefits associated with the avoided supply interruptions that are not captured by the SPD calculation are

"non-monetary", whereas those associated with notional wholesale market effects, as depicted in Figure 8, are "monetary". We are not sure this distinction is correct or useful. It seems to us it is incorrect in that the effects of outages are potentially very real and monetary, and precisely what VoLL tries to estimate. By excluding potentially very large portions of value, would we not be significantly understating the economic benefits of the transmission system? Being so partial, can the SPD benefits be meaningful?

14 Secondly, our understanding is that the transmission components that will be valued by the various SPD solve pairs are those additions (greater than $2 million) that have been built since May 2004. We do not understand this cut-off date. Surely all interconnection components need to be modelled? If they are not, doesn't this lead to unusual results across the country? For example we are reasonably sure that nothing very material has been added to the upper south island interconnected grid since May 2004. We think this means that it cannot generate any material private benefits since the associated assets are not subjected to an SPD benefits calculation, and that the associated cost will therefore all end up in the residual. This looks to us like it will simply produce a whole set of different cost allocations across the country and participants, and we cannot see that these are meaningful. They certainly appear to be arbitrary. Moreover the resulting cost allocations will presumably change, possibly quite significantly, as new assets are built and added to the SPD process.

15 Conversely it could be argued that only investments made *after* the proposed new TPM comes into force should be subjected to the SPD benefits calculation, as only these can have been influenced by the enhanced lobbying, and improved investment decision-making, that apparently flows from the TPM. The cost of existing assets is sunk irrespective of their economic merits.

16 Thirdly, the results shared in the paper and supporting information show that none of the modelled investments have private benefits that exceed their cost. Is this just showing that key components of economic benefit are missing, particularly where the investments are primarily to support reliability? As the paper acknowledges (para 5.6.66), a number of significant recent investments were indeed reliability investments (eg NIGUP and NAAN, see footnote 108, page 101), so we would not expect a significant amount of private benefit from them under the SPD approach. Why then would they even be included in the calculation?

17 We note in this regard that the benefit calculations are capped at the cost of the assets. But the costs are not meaningful if expressed over anything less than their calculation period, which is annual. If capped in each half hour (at the annual cost divided by 17520, which we understand to be the approach) then the *calculated* private benefit can *never* be equal to the cost over a year, irrespective of what the *actual* private benefit is.[1] We cannot see this is sensible. Many and perhaps most incremental network investments are to support growth in peak

[1] Unless the private benefit was as high as the cost in every half hour of the year.

demands, and the increments will not be "used" (or provide any benefits) much of the time. Moreover they will tend to be used relatively little at the start, and a lot more at the end of their lives. In this sense network investments are like peaking generation plant, which could never be viable (in an energy only market) if the price it received was capped at some average half-hourly cost as calculated on an annual basis.

18 The rationale for capping is perhaps to ensure that Transpower does not exceed its MAR, but if so then preferably this should be handled by the residual (we can see no problem with this being a credit, be it in any half hour or overall). If capping must be applied, then it should at least be done at a much higher level, for example monthly totals.

19 Fourthly, a key driver of the claimed dynamic efficiency benefits of the proposals is better investment decision-making, even though the investment decision-making process itself is not addressed in the paper.[2] The effect is supposed to come from the beneficiary-pays approach creating greater incentives to participate in the investment decision-making process (page 98, para 5.6.55 (a)). We cannot see how it can provide this incentive, particularly insofar as it relates to the risk of over investment. If investment in an unnecessary transmission investment is approved, it cannot lead to any party being charged for private benefits, since there are none according to the proposed method: the supply curve does not move up when the transmission component is removed in the second SPD solve. In fact the new approach ensures that the full cost will be assigned to the residual, with attendant muting of incentives. Have we got this wrong? Put another way unless the method actually improves investment decision-making in a material way ex-ante, it cannot achieve the claimed benefits.

20 Fifthly, does the illustration in Figure 8 (page 91) adequately capture the electricity market reality? As we see it there is (at least in SPD solves) no demand curve, there is just the actual quantity, and that quantity will be the same in both solves. Supply 'curves' are not curved, but stepped. The removal of the transmission component may move the supply 'curve' up as depicted in Figure 8 (by sufficiently reducing access to lower priced steps), and with a given quantity there will therefore be a higher price, but with an effectively vertical demand curve we struggle to see how the various areas that appear in Figure 8 eventuate? We are thus unsure how the model has come up with the change in benefits, and more importantly what if any meaning can be attributed to the values generated. On the other hand if everything does work with a *correctly* drawn Figure 8, then that is what should be used to explain what is going on.

21 Finally it is not clear to us who the parties in the benefits calculation are and how this relates to charging. Figure 8, though heavily stylised, is clearly representing the wholesale market, and the paper also discusses participants structuring bids and offers to manage exposure to benefit-based charges, suggesting this is

[2] The link to investment decision-making process is discussed further below.

about generators and purchasers (para 5.6.34 uses “retailers”, but we presume this should be “purchasers?). The same para suggests “there may be efficiency gains from levying the charge on retailers rather than distributors”. Given the calculation, and the fact that distributors, as distributors, are not wholesale energy market participants, surely the presumption is that the relevant portion of the benefit-based charges would fall on purchasers, not distributors?

22 We note in this regard that purchasers - unlike generators, distributors and direct connects - do not (as purchasers) have contracts with Transpower. Can Transpower invoice them? Since any invoice involves payment risk, and some purchasers will be of lower credit quality than others (and perhaps all will be of lower credit quality than most distributors), can Transpower impose prudential requirements on purchasers? Will these prudential requirements align with the wholesale market, or with the - much less onerous - distributor prudential requirements?

23 In summary the SPD benefits approach does not pass the “smell test”. The benefits calculated do not appear to be meaningful or accurate estimates, and there is no reason to believe that they will improve the quality of grid investment decisions.

Consistency with the grid investment evaluation process

24 As noted above, the proposed method seems to clearly indicate that the private benefits associated with all recent significant grid investments are between somewhat less and much less than the cost. There is a clear implication that these investment decisions were wrong. If the SPD based calculation is indeed conceptually robust and meaningful, then surely it needs to be the basis of the grid investment evaluation process?

25 Yet the paper effectively places the investment evaluation process off limits. Participants might lobby the process based on private benefits of grid investments, but then they might not. The nature of most grid investments, and indeed most network investments, is that they are sunk costs. As a country, we don’t want to find out that major pieces of infrastructure were unnecessary (or unnecessarily early) *after* we’ve built them. The Authority should back its method and address this inconsistency directly so that the dynamic benefits from the new approach are realised. This inevitably involves changing the process that the Commerce Commission and Transpower go through, and we submit this has to be done, or at least it has to be agreed that it will be done, before the SPD aspects of the proposed TPM changes are implemented.

The stability of resulting cost allocations

26 More even than the existing TPM, the proposed TPM is very clearly just a cost allocation model, not a pricing model. There are no prices for interconnection that are analogs for the existing “price” per kW currently established each year

by Transpower using the previous year's RCPD results[3]. (This price, while arguably lower than the LRMC of transmission investment, is at least in the ball park, and has been incrementing, reasonably predictably, in line with Transpower's grid investment.)

27 Under the proposal, Transpower's total revenue requirement for the year ahead will be established pretty much as now and Transpower will need to state how much is to be recovered from interconnection charges in total. But how that total falls across components and participants would be indeterminate in advance under the proposal. This is in stark contrast to the status quo, where parties know their transmission costs for the year ahead with near certainty.[4]

28 In our view, a key component missing from the initial paper - although it may have been provided in later documents - is an assessment of how the charges will vary across the year and across participants, for various scenarios. We are not in a position to do this analysis, but we are reasonably sure that the SPD private benefits calculation will lead to highly variable results, while the LCE is notoriously variable, which means the residual must also be highly variable. Because participants' relative exposure to the various components is not uniform, it will be difficult for them to predict costs. Further, because different participants have different ways open to them to recover costs, the cost could feed through to consumers as higher prices (by way of higher risk margins) and / or more variable prices.

29 Uncertainty and variability is not of itself a problem, and the spot energy market creates plenty of it. However variability that has no underlying economic basis but is simply the result of a particular administrative mechanism is, we submit, inefficient.

30 We discuss below the possible wider consequences of the proposal, but we can state here that the volatility is, on the face of it, a very strong reason for a distributor to opt out of this component of the charges (as allowed under the proposal). This will mean there will be no *direct* benefit to Orion, and therefore to consumers, of our coordinated load management activities in the upper South Island. This benefit may still flow through via other channels, but we doubt it.

Allocation of the residual

31 We make two observations here.

32 Firstly, we do not see that the 50/50 allocation of the residual cost between load and generation has any economic basis. We find the rationale (in para 5.6.80) - that 50/50 is a reasonable basis because generation is approximately equal to

[3] Although this price is itself just the result of dividing Transpower's interconnection revenue requirement by the sum of the regional RCPD kW.

[4] Interconnection and existing asset connection charges are known with complete certainty. There is some doubt as to the value and timing of new investment agreement charges, but this is usually a very small proportion of the total transmission cost.

load - to be unconvincing, particularly in contrast to the sophistication and granularity of the SPD method. Given that the residual is likely to be significant, the way it is apportioned has a material impact. The sharing itself therefore needs to be well founded lest this become fertile new territory for dispute. Does the beneficiaries-pay approach shed any light on an appropriate allocation? Our own view is that, at least with respect to the cost of reliability investments, a much greater than 50% share should go to the load side, as the economic consequences of outages on consumers are much greater than they are on generators.

33 Secondly, the selection of RCPD and RCPI for residual allocation (irrespective of what proportion of cost each group gets) is not well founded in the paper. For something that is described in the paper as being in the nature of a tax[5], it seems odd that RCPD and RCPI which (at least as applied in the current TPM for RCPD) focus on just a small part of the (previous) year should form the basis of the residual cost allocation for the following year? Since the SPD benefit calculation is supposed to be providing the correct economic incentives, we would have thought that a uniform market share based allocation was superior to RCPD/RCPI, since it rightly (rightly within the proposed framework) provides no incentives to manage or shift load.[6] For reasons discussed in the next section, a market share allocation would also make residual allocation simpler, and is probably closer to how participants will perceive the charge in any case.

34 On the other hand if RCPD is still seen as a useful price signal for peak avoidance - which is how it is described in some parts of the paper - then the impact of making that signal much weaker and much more volatile needs more careful consideration.

The practicality of the associated billing process

35 A key consideration for us when contemplating changes to our own pricing approach is whether any new approach can, as a practical matter, be billed, and in a way that invoice recipients can understand and verify. We appreciate that the proposal effectively leaves this detail to Transpower, but we believe that key aspects may be impractical, which will make it very difficult for Transpower to deliver, and that such practicality is a relevant consideration at *this* stage of the process. Moreover if participants need to be able to run SPD in order to verify invoices, that, at best, favours better resourced participants.

36 In order to consider practicality, we have limited ourselves to just the interconnection component, which is where the change is most notable. We put ourselves in the position of Transpower in early May 2015 looking to invoice for April 2015. We assume Transpower has already divided its annual

[5] Executive summary, page D, para 26.

[6] Load management in relation to reducing a cost that is described as a tax is arguably tax avoidance?

interconnection revenue requirement up over the 12 months of the year on some basis.

37 Step 1 will involve deducting the LCE from the monthly requirement. We note that, currently, the LCE comes through with a monthly lag on Transpower invoices, so we presume this process would therefore need to be sped up. However can it actually occur before wholesale market and FTR settlement? If the lag remains there will be a temporal mismatch between the wholesale market that is driving the SPD calculation, and the wholesale market that is generating the LCE.

38 Step 2 is we think relatively straightforward: SPD is run as described and calculates a set of private benefits, which are then allocated across participants (generators and purchasers separately, and after that presumably by their market shares at the relevant GIPs/GXPs in the relevant half hours?). Whether participants understand the amounts is a separate question.

39 Step 3 involves calculation of the residual, a trivial calculation so long as the total cost and LCE is known. In principle the residual could be positive or negative. There are open questions about the need for and nature of any capping in the SPD calculation - see above - and also the calculation location (GXP, region…?) and period (half-hourly, monthly…?).

40 Step 4 is where things start to get tricky. Allocation of the residual is to be based on RCPD/RCPI. But which ones? Currently the measurement period for RCPD[7] is the year ended 31 August, and the quantities then feed into an allocation notified in November to apply from the following 1 April to participants who are the same parties that set the demands in the measurement period. The annual measurement encompasses at least the idea that it is appropriate to allocate cost according to regional peak demands, and, within regions, loads' (distributors' and direct connects') shares of peak demands, that are measured over a year.

41 Within the new proposal the measurement period is unclear. If it remains as the previous year's result then that is at least a stable share (but not a stable amount) from month to month, although the meaning in terms of the value of peak avoidance is lost. And to the extent this is any sort of signal, it relates to allocating residual amounts that will be higher the less need there is for investment. This is because the residual is highest when the private benefits are lowest.

42 If the residual cost is allocated to purchasers (via distributor opt-out) last year's purchaser shares of a distributor's RCPD have no meaning in the month in question, so a further step will be needed to split up the regional share into purchaser shares, presumably by market share in the relevant month?

[7] We leave generators to comment on the possible implications of using RCPI for their residual allocation. We imagine there is some danger in pursuing an analogy with load.

43 Step 5 is the wash-ups implied by the charging of purchasers whose reconciled quantities change over time. As we see it this will mainly involve repeating step 4, but the point is that Transpower does not currently do routine wash-ups, with consequent processing and, potentially, use of money components. It will either have to develop this capability, or outsource the function (for example to NZX). Either way this may well involve material costs.

44 On the other hand it might be contemplated that RCPD quantities would be more regularly updated, say based on the previous month. But they would then have no link to annual maximum demands which (at least in the current framework) are a key input to investment decision-making and instead will reflect shares of monthly maximums. Not only will these be even more variable, they potentially encourage perverse load management response where participants try to minimise shares throughout the year even though demands are not (compared to annual results) high.

45 On the assumption that distributors do indeed opt out of being recipients of the residual interconnection charges, thought also needs to be given to what purchasers will logically do to recover them. Because a purchaser's residual charges will primarily reflect their market share in the current month, and have very little to do with their (or anyone else's) contribution to the RCPD peaks set the previous year, we consider that the cost will appear to them as being MWh based, and therefore the best approach for them to recover these costs will be a flat $/MWh rate. We suspect generators will face similar drivers.

Consistency in the treatment of the loss and constraint excess (LCE)

46 The Authority proposes to "codify that LCE received by Transpower from the clearing manager is to be used to offset the components of Transpower's transmission charges that correspond to the origin of the rentals." (para 5.3.6) This will not include codifying the actual methodology, but rather will require that the "methodology…must have the purpose of offsetting transmission charges to customers of those assets." (Same para).

47 We do not believe the two requirements implied above are consistent, or if consistent, clear enough to be useful. The "origin of the rentals" is the modelling of marginal losses and constraints in SPD, and the relative and absolute prices of offered generation around the country. To the extent that the configuration of the grid contributes to LCE, it can reasonably be said that it all does. Likewise any method of calculating and crediting that gets any LCE received by Transpower back to "customers" ticks the "purpose of offsetting transmission charges" box.

48 We think the codification needs to be more specific, as Transpower's current method is, in our view, intimately linked to the current TPM via the specific calculation of LCE arising from the HVDC (which may itself be affected by the introduction of inter-island FTRs), which is currently allocated to those that pay for it, and the allocation of the remainder of the LCE to loads (distributors and direct connects) only.

49 Moreover, since the LCE does not - as we understand it - currently form part of Transpower's MAR calculation, and is not treated by Transpower as regulated revenue, then LCE does not reduce participants' transmission costs directly, it does so via the LCE allocation process. The proposal (see Figure 7, page 89) seems to propose that the opposite will be the case: LCE *will* be revenue for Transpower and therefore reduce the residual component. We believe this requires a change to Transpower's price path regulation.

50 A minor technical point on LCE, Transpower's current allocation method calculates a very small (<1% of the total for Orion) LCE **charge** in relation to connection assets, even though the overall amount including the interconnection allocation is always a credit. In other words the method calculates a loss and constraint **deficit** for many connection assets. We would much prefer that the method not do this in future when distributors could well only be the counterparty for connection charges and therefore small LCE charges associated with connection assets which we would still have the administrative burden of passing through. We see no problem with the full LCE bucket of credit being allocated. This should also make calculation simpler.

Regulatory and other considerations for distributors

51 The proposal does not adequately consider the regulatory implications for distributors.

52 The most significant omission is any discussion of the treatment of transmission cost under the default price quality path (DPP) regime that regulates the prices of non exempt distributors. Transmission costs are indeed a pass through type cost under the DPP.[8] But this does not mean they have no regulatory implications. Distributors in setting prices for the year ahead must forecast transmission costs for the period in order to set compliant delivery prices. However if actual transmission costs turn out to be less than we expected at the time we set prices, this can cause us to breach our price path – a very material matter.[9]

53 Currently we can forecast transmission costs with considerable accuracy, as most is known with certainty well before the start of the relevant year.[10] There is a small amount of uncertainty associated with the timing of new customer investment contracts, but that is usually only a small component of the total. As we understand the new approach, there will be considerable variation in the interconnection component. We appreciate that distributors can opt-out of this component of the charges under the current proposal, with possible

[8] See p58, para 4.4.6 (d) of the paper. Actually now a so-called "recoverable cost" which is a slightly different idea, but close enough for the purposes of this discussion.

[9] We also face the commercial risk that we under recover transmission costs, which is obviously greater the more variable the cost is.

[10] Usually by late November for application over the year commencing the following April.

consequences discussed further below. However, there is some chance that the opt-out idea might be removed, which leaves the issue unaddressed.

54 As with the process of grid investment evaluation, we suggest that the Authority either consults with the Commerce Commission regarding possible changes to the DPP that might be required by, or might assist with, the implementation of the proposed new TPM, or makes it clear that all interconnection charges fall to generators and purchasers directly, and not distributors.

Possible unintended consequences

55 The example above shows that distributors are likely to opt out of the interconnection component of charges if they can, to avoid much greater compliance and under-recovery risk. However this will inevitably change the incentives on distributors (directly) and consumers (indirectly). As noted above, Orion, in conjunction with other upper South Island distributors, coordinates load management (USILM) in the area so as to manage interconnection costs via RCPD in the short term, and defer transmission investment, and therefore cost, in the medium to long term. Both short and longer term benefits are effectively passed to consumers (via retailers) under the current TPM. Distributors do not benefit commercially from any reduction in transmission costs that results from USILM.

56 Any revised TPM that reduces or removes (via opt out) the interconnection component of our costs, reduces the direct benefit of USILM. At this stage we have no intention of changing or stopping USILM, however the direct cost benefits that we can pass on will inevitably reduce. This may over time reduce the appetite of distributors to carry out the activity, particularly if it becomes much less clear that or how the benefits flow through to consumers.

57 The proposal anticipates that purchasers would be incentivised to continue supporting, and perhaps even pay to procure, this sort of service. However, we feel that the incentives on purchasers will be much more muted given their (usually) nation-wide markets, the variability and overall short term “zero sum” nature of the residual cost allocations, the much smaller size of the residual component and purchasers’ inevitably shorter term focus. On balance we think the outcome will, over time, be *less* interest in coordinated load management to manage transmission costs, to the long term detriment of consumers – the very opposite of the Authority’s statutory objective.

58 A related possible unintended consequence is on large consumer load management response. For around 20 years Orion has maintained a form of pricing that signals the long run average incremental cost of distribution **and** transmission for our largest 400 or so connections – so-called major customer connections. The signals reward customers for demand reductions during the 100 or so hours of highest demands on our network at a price of around $160/kW/year, and around $63 (40%) of that relates to transmission. Export at peak times is similarly rewarded. These customers invest, and have invested, against this price signal to reduce peak demands on the distribution and

transmission networks. Examples include: on-site generation capability, demand management systems and dual fuel heating systems. We observe around 20MW of response from this group during system peaks. Clearly the level of such investment will reflect our combined price signal.

59 The proposed changes in the TPM will substantially reduce or remove the transmission component of our prices for such customers, potentially undermining existing investments, and certainly reducing the returns to further investment. Again we *might* see a similar transmission price signal reflected in the offerings of retailers, but again we doubt it.

60 It is in this area that the paper betrays a lack of understanding of distributor pricing of the transmission component of the delivery service. While transmission costs are indeed pass-through cost, this does not mean that distributors simply allocate the cost amongst retailers. Most distributors set defined transmission prices to recover their expected transmission costs, and the structure of those prices usually reflects the overall structure of their prices, meaning that any cost reflective elements will be *reinforced* by the transmission component, as in the specific example above.

61 A final example of unintended consequences is on retail competition. The Authority has been implementing changes in the area of standardisation - prudential requirements and CGA indemnity for example - that amongst other things attempt to reduce the cost and risk for new entrant retailers. Yet we suspect the proposed TPM will introduce new and significant uncertainty and volatility into entrant retailers' costs, with no obvious means of managing that uncertainty and volatility. This looks like another reason for potential entrants to stay away. As far as we are aware the Authority has not done any analysis on this aspect, which is surprising given its concerns elsewhere about barriers to entry.

Concluding remarks

62 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

Bruce Rogers
Pricing Manager

Appendix: Responses to specific questions

	Question	Response
1	What are your views about the materiality of changes in circumstances since the current TPM came into force in 2008?	We do not believe the changes listed are material: • the first is a confirmation that many of the key transmission investments for the next 10 to 20 years have already been made, and the associated decisions, good or bad, cannot be undone • the second is largely a transfer of functions along with their decision making frameworks • the third may be of interest had this been a reason for not implementing such approaches (SPD-based benefits modeling) in the past. Was it?
2	What comments do you have on the process that the Authority has outlined for developing and approving a new TPM? Describe and explain any variations to the process that you consider desirable.	We consider that the process is adequate. We are less sure that the first step in the process - consultation on this paper - has been adequately executed. In particular the way that supplementary information has been produced in a piecemeal fashion following the initial paper has caused concern. It is good that the Authority extended the deadlines, but it has become harder over time to get a sense of the coherence of all the material provided. The Authority has not produced an updated version of the paper that relates all of the additional information and analysis to its proposal.
3	Do you agree with the Authority's view that the arrangements under the TPM for recovering connection costs are generally efficient? Explain your answer.	We believe there are still material boundary issues regarding whether assets are classified as connection or interconnection. In Orion's network we have in the past faced what we consider to be perverse incentives regarding electrically very similar solutions at Bromley and Islington. Investments at Bromley would be treated as connection investments - we would bear the full cost - while those at Islington would be treated as interconnection - we would bear about 10% of the cost. Some of these connection / interconnection distinctions seem to reflect little more than whether there are multiple counterparties that might benefit from an asset, and it would be odd if, for example, distributor mergers lead to a change in the classification of an asset. Within a broad "beneficiaries-pay" context there would be value in revisiting the way the connection / interconnection boundary is established.
4	What comments do you have about the potential for inefficient outcomes to arise from incentives to shift connection costs	See our response to 3 above. Please also refer to the ENA submission on this subject.

	Question	Response
	into the interconnection charge?	
5	Do you agree that there is the potential for inefficient outcomes to arise from incentives for connected parties to hold out for connection asset replacement to occur as a grid upgrade rather than under an investment contract? Explain your answer.	In theory, yes. However, please refer to the ENA submission on this subject.
6	Do you consider that there are any other problems with the connection charging arrangements under the current TPM? Provide a detailed explanation of the nature and materiality of the problem.	The way that Transpower carries out allocation of shared connections costs could be improved. For example at Coleridge the assets are clearly largely there to support the connection of the local generation. Yet, because most of the assets are classified as interconnection, and because Orion happens to supply a few small customers, the connecting generator picks up only around 10% of the cost of what are very specific local assets. However this is a comparatively minor issue, and we do not know how often it occurs in other areas.
7	What comments do you have about the Authority's analysis of the private benefits deriving from the HVDC link?	We are puzzled by the analysis. See our response to question 8.
8	What comments do you have about the consequences of the material differences between private benefits from the HVDC link and HVDC charges?	We note the results set out in para 4.3.9 that show a PV of benefits to SI generators from Pole 2 of $540m against a PV of charges of $500m. This suggests the benefits to generators alone of the HVDC are greater than the costs. This seems to conflict with the information elsewhere about the private benefits of Poles 2 and 3 which are shown as being much less than the costs.
9	What comments do you have about the Authority's analysis of the costs of inefficient generation investment resulting from the HVDC charge?	None.

	Question	Response
10	What comments do you have about the Authority's analysis of the costs of inefficient operation of South Island generation resulting from the HVDC charge?	None
11	Do you consider that there are any other inefficiencies arising from the HVDC charging arrangements under the current TPM? Provide a detailed explanation of the nature and materiality of the inefficiencies.	No comment.
12	What comments do you have about a) the differences (including their materiality) between private benefits from interconnection assets and interconnection charges; and b) the consequences of those material differences?	The real question is whether the stated benefits are meaningful. If NZ has indeed made a number of poor large sunk cost investment decisions, then clearly that decision-making process should be the direct and primary focus of review. In the current proposal it is not. On the other hand if there is no useful relationship between the calculated private benefits and the overall economic benefits of transmission investments, then we think the approach is simply misleading and unhelpful.
13	What comments do you have about the Authority's analysis of the problems with interconnection charges?	The more important question is whether the proposed new mechanism is an improvement. We do not see that it is.
14	Do you consider that there are any other problems with the interconnection charging arrangements under the current TPM? Provide a detailed explanation of the nature and materiality of the problem.	See answer to question 13.

	Question	Response
15	What comments do you have about the Authority's view that a prudent discount policy may be necessary after taking into account the incentives provided by the price components of any revised TPM?	Because any pricing methodology inevitably involves considerable averaging it is almost certain that it will not efficiently encompass all possible situations. It is thus desirable to maintain a prudent discount policy. However, the policy should be clearly stated and consideration should be given to making public any decisions under the policy.
16	Do you agree there would be efficiency gains from each of the components of the proposal for the connection charge, as outlined in paragraph 5.4.9? Please provide an explanation for your answer.	Please refer to the ENA submission on this topic.
17	Do you agree that the proposal will address the problem identified in chapter 4 in relation to the connection charge? Please give reasons for your views.	The requirement to enter into a CIC for upgraded or new assets generally leads to a good discussion around the alternative engineering options and teases out the best solution (distributor or Transpower build etc). However, there seems to be an issue emerging around the ongoing replacement of assets originally funded via a CIC. Our impression is that the cost of these replacement assets goes back into the NZ Connection Asset pool and so affects the ARR. Perhaps the TPM review should clearly document the intended process around CICs so that consistency between contracting arrangements is assured and this can be properly debated.
18	What comments do you have about the Authority's assessment and conclusions about a kVAr charge to recover static reactive support costs?	We are generally supportive of the proposal. In most cases it is likely that transmission reactive support will be lower cost than distribution reactive support, but this is not necessarily the case, so whatever arrangements are in place should not rule out distribution options. Given the way Transpower's overall revenue requirement is to be determined and how it is then allocated to the various components and counterparties, there is some risk that areas requiring reactive support end up paying "too much" overall. We also note this is another area where the respective regulation of Transpower and distributors needs to be aligned to support efficient outcomes.
19	Do you support:	We are generally supportive of the proposal. Given the lack of clarity elsewhere regarding the counterparty for the charges under the proposed TPM, we assume it is the connecting off-take party (distributor or direct

	Question	Response
	a) introducing a kVAr charge based on off-take transmission customers' average aggregate kVAr draw from the grid in areas where investment in static reactive support is likely to be required, at times of RCPD, at the long run marginal costs of grid-connected static reactive support investments? b) setting a minimum power factor of 0.95 lagging in the Connection Code for all regions?	connect) that would be the recipient of these charges?
20	Do you consider that there are alternatives to a kvar charge for recovering the static reactive support costs that the Authority has not identified that are practicable, would deliver a net benefit and would recover static reactive support costs? Explain your proposal.	We are generally supportive of the proposal.
21	What comments do you have about the Authority's assessment and conclusion about charging options for dynamic reactive support?	Please refer to the ENA submission on this topic.
22	What is your position on the Authority's proposal to codify that LCE or residual LCE received by Transpower from the clearing manager is to be used to offset	We are not sure the proposal has any content. Any method will, one way or another, offset charges as described. We think it would be useful codify to this in a way that clearly does not conflict with Tranpower's price regulation. Specifically that estimated LCE is (in future) included in Transpower's regulated revenue.

	Question	Response
	the components of Transpower's transmission charges that correspond to the origination of the rentals?	
23	What is your view of the Authority's assessment and conclusions about using the SPD or vSPD model to establish a beneficiaries-pay charge for recovering some or all HVDC and interconnection costs?	We are not sure these short term benefit calculations are a real or meaningful estimate of private benefits over the long lives of the assets. The use of a conceptually similar method, but over time horizons more appropriate for the assets in question, might well be a better idea. However the description of reliability benefits as "non-monetary" seems to us to be plainly incorrect. Common sense tells us that the transmission system provides benefits to all participants – there is effectively no electricity system without it. Any method that attempts to quantify the benefits but which does not in fact show significant benefits must surely be questioned.
24	Do you agree with the Authority's conclusion that the most efficient beneficiaries-pay charging option for applying to HVDC and interconnection costs is likely to be the SPD method? Please provide an explanation for your answer.	Because it is very short term, and potentially open to gaming, we think not. As far as we can tell, the paper has not addressed a more significant question about HVDC charges and their reallocation, which is: what will the incidence on consumers be? As previously submitted, by Orion and no doubt many others, any HVDC cost reallocated to distributors (or purchasers) will *definitely* find its way to consumers. The question is: will at least offsetting decreases occur in other parts of consumers costs via lower energy prices? If the Authority cannot answer yes with certainty, we believe this casts serious doubt on whether the statutory objective is achieved.
25	Do you consider that there are beneficiaries-pay options that the Authority has not identified that are practicable, would deliver greater net benefits and would recover HVDC and interconnection costs? Explain your proposal.	We believe beneficiaries-pay could, conceptually and with a much longer term focus, be used to calculate reasonable shares of transmission cost. It may also be a useful tool to support major investment decision-making. We note that material gains in the area (if there are any) relate to making the decision to build the right assets in the right place at the right time. If the proposed new TPM does not materially improve investment decision-making it cannot deliver material efficiency gains. By definition the beneficiaries-pay revenue will probably not fully recover interconnection costs (hence the residual) so we do not understand the last part of the question.

	Question	Response
26	Do you agree with the proposal to apply the residual charge to: a) generators and direct-connect major users; b) distributors, except where they opt out from the charge; and c) retailers, were distributors elect to opt out from the charge?	It is unclear who else it could be allocated to, so the question is how and in what proportions. How was the 50/50 split of the residual between load and generation arrived at? Given the large amounts of cost being allocated via this component it is rather surprising that virtually no attention is given to it. To the extent that the investments in question have reliability as a key driver we would have thought a much greater than 50% share should go to the load side. Given the likely volatility of various components of the proposed interconnection charges it seems sensible - within the proposed approach - that distributors NOT be the counterparty to any of these. The volatility of the three components togther (LCE, SPD and residual) will inevitably be less than that of the first two components alone. That would seem to be at least a partial natural hedge - a good thing - implying that purchasers should be the counterparty for all three components. However, note that this does not mean we agree with the proposed approach.
27	Do you agree with the proposal that distributors may opt out from the residual charge: a) to the extent that they do not benefit from offering interruptible load on the wholesale electricity market; and b) provided they consult with retailers that may be affected before they opt out?	The proposal does not explain how the offering of IL should make any difference to residual allocation. The paper discusses this possibility in the benefits (SPD) section, not in the residual section. Just because a distributor participates in IL should not mean it loses the ability to opt out for everything else. We believe the proposal will lead to volatile cost allocations. This creates financial and regulatory risk for distributors, which would be a strong reason to opt out. Whether this decision is an economically sensible one is a different matter. We are not sure it is sensible for each distributor to consult with all retailers as there may be a rather non-standard outcome across the country. We suspect most retailers would prefer a standard approach. Moreover it will probably be impractical for a distributor to opt out only with respect to some of the retailers on its network. We note that the proposal is unclear as to which participant on the load side (the purchaser or the distributor) is supposed to incur the “SPD benefits” portion of the total charges. We would have thought this was obviously purchasers? If the intent was that distributors can opt out of the residual portion only, we do not believe this is sensible. Opting out for distributors should be with respect to all components of the interconnection charges.

	Question	Response
28	Do you consider that the proposed RCPD/RCPI charge, designed to encourage efficient avoidance of peak regional use of the grid, with half of the residual revenue recovered from load and half from generators, would best complement a beneficiaries-pay charge that calculates charges every trading period using the SPD model? Explain your response.	If the SPD beneficiaries-pay component is indeed calculating correctly and achieving the dynamic efficiency benefits claimed, (and we are sceptical that it is) it is unclear whether avoidance of regional peaks is still a relevant consideration? The residual is described as being in the nature of a tax. RCPD does not look like a broad-based or well designed tax. In the case of RCPD, the cost to be allocated will be less than now, and it will be more volatile. For both reasons there will be less investment in the means by which peak avoidance is achieved. The residual is such an uncertain and almost random charge that we do not consider that any response to it can be characterised as "efficient". If distributors opt-out, the way any benefits of peak avoidance flow through to consumers becomes even less clear. We think that RCPD is much less useful as a signaling mechanism if it is diffused through a cost allocation mechanism to parties (eg purchasers) who are much less able to manage demand in a way that will reduce their costs. We think it likely that no matter how it is calculated, purchasers (and possibly generators) will perceive this as a charge that mostly just reflects volume market shares, and recover it as such.
29	Do you agree that the RCPD/RCPI charge would best meet the principles for an alternative charging option of: a) minimising the distortion in use of the transmission grid resulting from the imposition of charges; and b) ensuring the costs of providing the transmission grid, as approved by the Commerce Commission, are fully recovered so future investment is not stifled by concerns by investors that they will not receive a return on their approved	We do not see this is an alternative charging option: it is integral to the SPD beneficiaries-pay approach in an environment where the SPD benefits are partial and Transpower must still receive its revenue requirement. In this context RCPD in particular is very different under the proposal compared to what it is now. If the objective is indeed minimizing distortion in use of the grid, as opposed to efficient peak avoidance, an allocation based on market share would seem to be more appropriate. Regarding (b) this can be met by any method as Transpower's regulation ensures that it gets a return on approved investment.

	Question	Response
	investment? Explain your response.	
30	Do you agree that the Authority's preferred option for the residual charge should be an RCPD/RCPI charge designed to encourage efficient avoidance of peak regional use of the grid? Explain your response.	We don't think it has the same interpretation as before. The TPM overall should have this as an objective, but it will inevitably be muted under the proposal. Isn't beneficiaries-pay supposed to be the signaling component of the new TPM? Trying to encourage efficient avoidance of peaks via RCPD makes good sense within the current TPM but it is less clear that it does within the proposed TPM. Doesn't this approach contradict the objective of minimizing distortion in use of the grid (see question 29 (a))? We have no experience with RCPI, but we can imagine that it will need to be carefully designed to avoid perverse outcomes. We do not believe the analogy with RCPD is a reliable one.
31	What are your views about amending the existing prudent discount policy to provide that it: a) applies to disconnection of load as a result of investment in generation where this would not be privately beneficial in the absence of transmission charges; and b) may apply for the expected life of the asset to which the prudent discount applies? Explain your response.	No comment.
32	Do you agree with the assessment of the economic costs and benefits of the Authority's TPM proposal versus the	We are not convinced the proposal is materially better than the status quo, and in some areas it is clearly worse. Because the SPD benefits calculation is incomplete, and in any case not part of the grid investment evaluation process, we do not think that any dynamic efficiency gains will result.

	Question	Response
	counterfactual? Explain your answer.	Even with the proposal, a small variant that dropped the SPD benefits calculation and simply combined HVDC and HVAC costs and then split the total 50/50 between load and generators would not in our view lead to materially different outcomes (cost allocation wise). That said the 50/50 split of the residual allocation itself appears to have no rigorous basis, and could easily become a future area of dispute.
33	Do you agree with the assessment of the costs and benefits of the TPAG majority proposal against the counterfactual? Explain your answer.	No comment.
34	Do you agree that the Authority's TPM proposal meets the Authority's objective? Explain your answer.	We believe there is significant risk that the long term benefit of consumers will not be served by the key changes in the proposal. This is by way of potential cost increases, reduction in beneficial load management and participant responses to managing cost volatility.
35	What comments do you have about the Authority's evaluation of alternative market-based and market-like approaches for the recovery of transmission costs?	Some have been ruled out on the basis that they are not currently lawful. But law and regulation itself can be changed.
36	What comments do you have about the Authority's acceptance of the TPAG's evaluation of alternative exacerbators pay approaches for the recovery of network reactive support costs?	No comment.
37	Do you agree with the Authority's assessment and conclusions about alternative beneficiaries-pay options for establishing transmission charges to	The fundamental question is whether dynamic SPD based assessment of benefits is materially better than possible other beneficiaries-pay approaches. We think a more enduring and stable cost allocation linked to benefits could be devised that achieved much the same result at much less cost.

	Question	Response
	recover HVDC and interconnection costs? Please give reasons for your views.	
38	Do you consider that the draft guidelines provide the guidance necessary for Transpower to develop a TPM that reflects the Authority's preferred option? Explain your answer.	There may well be detailed technical issues that make implementation of the proposal (as it stands) difficult or expensive. The most important of these should, in our view, be identified and assessed (even at a high level) before detailed design commences. We note the recent difficulties in the area of dispatchable demand.
39	Do you have any suggestions for amendments to the draft guidelines to ensure that they provide the guidance necessary for Transpower to develop a TPM that reflects the Authority's preferred option?	Given the amount of discussion already generated by the proposal, we cannot help but think that significant changes are likely in consultation. It might therefore be best to leave the guideline drafting till after the design is settled.
40	Do you agree with the Authority's proposed process that Transpower should follow in developing the TPM? Explain your answer.	The process seems reasonable.
41	Do you agree that the Authority does not need to require Transpower to propose how costs related to revenue not subject to regulatory review by the Authority or the Commerce Commission would be determined and allocated? Explain your answer.	Yes. This would seem to be outside the purview of the Authority under the Code? We note that LCE is not currently, as we understand it, regulatory revenue for Transpower.
42	Do you have any suggestions for amendments to the Authority's proposed	No

	Question	Response
	process that Transpower should follow in its development of the TPM?	
43	Do you have any comments about the Authority's proposal that Transpower should propose a timeframe to the Authority that would achieve the Authority's objective of having the amended TPM in place in time for the April 2015 pricing year?	This is OK, but it must be acknowledged that the time frame could slip as the full implications of the proposal are revealed through detailed design.
44	Do you agree with the Authority's proposal to decide on the consultation period after the proposed TPM has been received from Transpower?	No comment.