19 December 2014

Transpower New Zealand Ltd.

By email: *micky.cave@transpower.co.nz*

SUBMISSION ON 2014/15 TPM OPERATIONAL REVIEW: SECOND CONSULTATION PAPER

1 Orion New Zealand Limited (**Orion**) welcomes the opportunity to comment on the "2014/15 TPM Operational Review: Second Consultation Paper" (the **paper**) released by Transpower in November 2014.

2 Our submission is in three parts:

- General comments on the paper;
- Responses to consultation questions as Appendix 1 (we have not responded to all the questions); and
- Some more detailed commentary on the way 'N' and region definitions influence the allocation of charges as Appendix 2.

3 Some of this submission revisits material covered in our submission on the Electricity Authority's problem definition working paper, and we recommend that Transpower reads that submission as well. Indeed most of the submissions on that working paper provide useful background and context, particularly as regards HAMI and RCPD.

4 The Electricity Networks Association (ENA) has also submitted on the paper. Orion endorses the ENA submission.

General comments

5 Our comments primarily relate to the proposals around RCPD.

6 While we agree with much of the discussion in section 4 of the paper, we consider that it is important to note that, at least with respect to the USI region, the load projections reflect the extensive load management that already occurs. Thus, in considering the strength of signals, as much or more attention needs to be paid to existing response as to further deferment opportunities.

7 We note that section 4 includes under the heading of "Other USI context" the paragraph: "For the last six years, Orion has co-ordinated a regional control programme amongst USI distribution businesses." However there is no discussion of

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the relevance of this to the proposals in the paper. As we have noted in a number of submissions, we believe that load management in its various forms – peak load control, off-peak water heating, major customer load management and on-site generation – has over the years lead to Orion's peak demands now being around 150MW (20%) lower than they would otherwise be, and pretty much all of this response pre-dates RCPD. This context is particularly important when we come to section 4.5 of the paper which reports that demand response is a viable method of deferring transmission investment. Indeed it is, and most distributors have been doing it for decades leveraging long-term relationships with consumers who themselves have made long-term investments. However, it is odd that Transpower is progressing with its own DR programme when it has elsewhere in the paper established that there is very limited value in transmission investment deferral for the foreseeable future. We also note the table embedded in Figure 6 that indicates that Transpower's own calculations show that its DR programme is more expensive, on a $ per MWh basis, than control of hot water heaters.[1]

How many half-hours?

8 Section 5 of the paper focusses on 'N'. We support the conclusion here, but for somewhat different reasons.

9 We believe that charts like Figure 6 significantly overstate the sharpness of the N=12 pricing signals, as it assumes perfect knowledge of when the 12 periods will occur in the 12 month September to August assessment period. We know with reasonable certainty that, at least in the USI, the 12 peaks will occur on working weekdays from May until August, but we have no idea exactly when they will occur in that period, or how many potential candidates there will be. This means that consumers, who generally know even less than we do, will not be prepared to invest anything like the amounts implied by Figure 6.

10 We expect to be actively managing load, both locally and as part of the coordinated USI programme, for many more than 12 half hours each year, and over the last 5 winters we have controlled for between 60 and 300 half hours. It is for this reason that we consider that a choice of N = 100 much better aligns RCPD price signals and the practicalities and economics of load management and demand response.

11 We also note that, where there is a difference between 'Ns' across regions, the regions with smaller 'Ns' face a slightly higher share of the total interconnection cost than is appropriate, and equalising 'Ns' is one way to deal with that.

Pricing regions

[1] And even then the incremental costs of traditional load management for transmission reasons is much lower than the stated range given that much of it will be occurring anyway for local network reasons, and even when it is done for those reasons it is within a framework of service levels that mean most consumers do not even know that it is happening.

12 In Orion's view pricing regions should reflect the grid configuration and the areas where there is common ability to manage the drivers of network investment, and it is certainly appropriate to review this from time to time. However, we do not support redefining or amalgamating existing regions just because there is no medium term need for investment – that is what 'N' is for - or because there may be issues in one region such as Tiwai in the LSI.

13 We agree that Tiwai's influence on LSI RCPD results is problematic and may be leading to inefficient outcomes in terms of smelter operation. However, while we have no analysis to call on, we prefer both from a conceptual and a transparency perspective that this be resolved via a bespoke arrangement that involves removing Tiwai from the LSI region and separately assessing an appropriate charge or chargeable quantity. This will not be a simple exercise, but we believe it is superior to an ad hoc amalgamation of regions that effectively hide the problem.

14 If the amalgamation of UNI, LNI and LSI regions does proceed it would reintroduce, with respect to the USI, the unfairness associated with the existing split of N=12 and N=100 regions, and would inappropriately disadvantage USI simply by arithmetic. We appreciate that the percentage increase in USI interconnection charges is small (stated as 1.45% on page 41), but that is still around $1 million per year for Orion network customers, and we see no reason to accept this. There is a similar effect caused by the relative size of the current regions (see Appendix 2 for more on this), and that would be made worse by the amalgamation of regions.

Concluding remarks

15 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 1: Response to consultation paper questions

No.	Question	Orion response
1	Do you agree that we should apply the following assessment criteria for our operational review: *1. is the option consistent with the TPM Guidelines* *2. is the option practical (taking into account the costs of change, and the desirability of consistency and stability over time)* *3. would better promote the long-term interests of consumers of electricity by:* • *promoting competition, reliable supply and efficient operation of the electricity industry* • *improving consumer welfare directly* • *reflecting customer preferences or* • *correcting errors or anomalies in the TPM?*	Yes. In terms of the four sub-parts of part 3 of this question, we note that the first is effectively the way the Authority clarifies its application of its statutory objective, so it should get considerable weight, particularly relative to the second and third. The second should not conflict with the first to the extent that it is long term consumer welfare that is being improved and not just reduction in cost in the short term. The fourth should be tested against the first. That is, the error or anomaly can't be classified as material unless it causes conflict with the first.
2	Do you agree that we should take into account both the efficiency and pricing impacts of any proposed change to the TPM when assessing options?	Yes.
3	Do you have any additional or alternative evidence on the problem definition for setting N?	Yes. See the body of our submission.
4	What would the impact of a change from N = 12 to 100 (in UNI/USI) have on the way that you respond to the RCPD charge/your investment decisions? We also invite submissions from industry participants and interested parties on the costs you may incur. (We note the distinction between genuine efficiency costs and distributional effects.)	It will have no material impact on our response or customer response, and on that basis we expect there to be no material change in cost.
5	Do you agree with our proposed recommendation that N be set to 100 for UNI?	Yes, provided it is also set to 100 for USI.
6	We would welcome views on two sub-options for setting charges in the non-USI areas:	We consider that all regions should be assessed using the same N (=100), and that the current regions should not be amalgamated for assessment

	• charges could be set on the basis of demand during the top 100 national peak periods i.e. including USI demand • charges could be set on the basis of demand during the top 100 peaks excluding the USI region.	purposes. We also note that larger regions provide a cost advantage, particularly for relatively small distributors in the larger region, when compared to smaller regions. We discuss this in more detail in Appendix 2.
7	Do you agree with our proposed recommendation that N be set to 100 for USI?	Yes.
8	Do you have any evidence either in support of, or against, setting N to 100 for UNI and / or USI?	Yes, in support of 100 for USI. As we note in the body of our submission, effectively managing RCPD requires a party to carry out load management activities for many more than 12 half hours. 100 half hours will be much better aligned with our actual load management activity. Our own experience with load management is that consumers respond best when peak periods are signaled, but we appreciate that this is a step too far in terms of the current consultation. However, it would appear to align quite well with Transpower's thinking on demand response which contemplates the response being called on in some way rather than having providers guess whether they should respond or not.
9	Do you agree N should not be set greater than 100 at this point? Please provide evidence in support or against setting N greater than 100.	Yes. We note the analysis, for example in Figure 6 that shows little impact on the strength of the marginal price signal from increasing N beyond 100.
10	Do you have any additional or alternative evidence on the problem definition for aggregation of regions?	We are concerned that the region aggregation is being proposed for the wrong reason. An aggregation based on use of shared assets largely dedicated to supply to the region strikes us as the most appropriate.
11	Do you agree that all regions where N = 100 should be amalgamated into a single region unless there are clear rationale for not doing so?	No we do not. We consider that the regions should be driven primarily by the nature of the grid, not by administrative concerns.
12	Do you have any evidence either in support or against amalgamating UNI, LNI and LSI?	See our response to Q11.
13	Do you have any additional or alternative evidence on the problem definition for the current HVDC HAMI charging?	No.
14	Do you consider that the HAMI charge has resulted in curtailment of South Island generation capacity expansion? If so, by how much and what evidence do you have that is robust enough for us	We accept that Meridian and Contact have said that it does and we have no reason to dispute this. By how much is an open question, since we believe the SI generators could enter into commercial arrangements that

	to rely on in support of your view?	would enable a more efficient sharing of cost that would make no party worse off, yet it would appear no such arrangements are in place.
15	Do you agree with our (tentative) proposal to recommend that the Electricity Authority consider changing the HVDC charges from HAMI to a diluted HAMI? What do you consider the optimal value of N would be for a diluted HAMI charge?	We support the tentative proposal. We have no views on the optimal value of N with respect to HAMI.
16	Do you have any evidence in support of, or against, the proposal to change HVDC charges to a diluted HAMI?	No.
17	Do you agree that a MWh charge would produce similar efficiency improvements as a diluted HAMI, but lower consumer benefits from lower prices?	No comment.
18	What do you consider the impact of a change from HAMI to a diluted HAMI or MWh would be on South Island generator offer behaviour, including the price that previously withheld generation capacity would be offered into the wholesale market at? (It would be appreciated that responses could include sufficient detail to enable us to model the generator offer behaviour, if relevant.)	No comment.
19	If we retain HAMI, what would your view be on: • expanding our use of the EOC mechanism to include System Operator warning notices, which have a lower threshold than grid emergency notices • using the EOC mechanism to aggregate grid injection points along river chains as an interim measure, or changing the TPM to allow river chain aggregation as a permanent measure.	Both seem sensible.
20	Do you agree that the nature and size of the pole maintenance cost and paralleling issues mean a quantified CBA is unnecessary?	No comment.
21	Do you agree that recovering pole maintenance cost in a smoothed manner is the best way to ensure the costs are recovered in a way that meets our customers' preferences, and is consistent with a market-like approach?	We are generally in favour of smoothing where it has no material adverse efficiency implications.
22	Do you have any additional or alternative evidence on the	No comment.

	problem definition for Pole maintenance cost recovery?	
23	Do you support our proposed recommendation to recover maintenance costs on an average basis ($/km) rather than an average cost basis?	No comment
24	Do you have any evidence in support of, or against, recovering maintenance costs on an average rate basis?	No comment
25	Do you have any additional or alternative evidence on the problem definition for paralleling?	No comment
26	Do you support our proposed recommendation to amend the TPM to address paralleling?	No comment
27	Do you have any evidence either in support of, or against, amending the TPM to address paralleling?	No comment
28	Do you agree a phase in period is not necessary for any of our proposed recommendations as they do not lead to large increases or decreases in current charges, and that the changes should be implemented for the capacity measurement period beginning 1 September 2015? If not, please give reasons, including evidence why phasing in would better serve the long-term interests of end-users, and, where you consider this to be the case, details of the phase in you would propose.	Yes, to the extent that none of the changes come close to causing rate-shock. However, we do not believe that this obviates the need to minimise undesirable impacts in the first place, for example the extra allocation of cost to USI that would result from amalgamating the UNI, LNI and LSI regions.
29	Do you consider that periodic clause 12.85 reviews will enhance the durability of the TPM?	Yes provided they are appropriately limited in scope. We do not believe that well-considered, proportionate responses to changes in circumstances show any lack of durability. Rather, they enhance it.
30	In what circumstances, and under what process, should future clause 12.85 TPM reviews take place?	No comment.
31	Do you have any feedback on the approach we have taken to this review and in particular whether there are things we could improve?	We appreciate that the review has taken a conventional analytical approach.
32	Do you have any additional matters you would like to raise as part of the clause 12.85 review?	No.

Appendix 2: More detailed commentary on RCPD, 'N' and regions.

The existing RCPD arrangements discriminate against the UNI and USI regions by taking the average of the top 12 loadings rather than the top 100 loadings. The magnitude of this interconnection charge discrepancy depends on the shape of the load duration curve, and in the past 3 assessment years has been:

Loadings in year to	12 Highest average	100 Highest average	Difference (kW)	Difference ($)
31 August 2014				
UNI	1,904,009	1,871,115	32,893	$3,629,767
USI	997,861	994,584	3,277	$361,568
31 August 2013				
UNI	1,913,523	1,871,357	42,166	$4,826,724
USI	1,009,813	996,998	12,815	$1,466,948
31 August 2012				
UNI	1,882,132	1,832,614	49,519	$4,924,151
USI	996,885	983,081	13,804	$1,372,641

Disadvantage caused by shorter averaging period

We understand that the purpose of selecting the shorter 12 half hour averaging period was to provide a more focused load response in the constrained areas, and the higher averaging result is an unintended consequence. We have been exposed to this penalty for the last 8 years.

Other than the slightly higher quantity noted above, the suggestion that the shorter averaging period provides an enhanced pricing signal is not valid within our area. With 12 half hours or with 100 half hours the price is still very close to $114/kW. The consultation paper appears to consider the lower energy value over the longer averaging period, but this would only be valid if customers responding to the peaks knew when those peaks would occur. In the absence of this knowledge, customers must respond for several hundred "likely" hours to be in with a chance of hitting the top 12 (because at any point in time of high loading, no one can know if a period of colder weather and even higher loading might occur in the future).

We propose that the averaging period in the current framework has no practical influence other than to disadvantage EDBs exposed to shorter periods. Longer averaging periods provide a less volatile result (which is desirable) and we submit that all regions should be set to the same duration, 100 half hours (or longer).

A second, more discrete penalty is hidden within the existing framework. This second penalty relates to diversity of load. EDBs within a larger region will receive a benefit from the extent to which their peak loading levels occur at different times to the region peak, and the bigger the region, the more this diversity exists. North Island regions are close to twice the loading size of South Island regions, and smaller EDBs within these regions attract an RCPD

result that is significantly below their own peak loading level, whereas Orion's RCPD result (571.8 MW last assessment period) is very close to its own peak loading level (577.9 MW during the same period).

The current proposal enhances this second penalty to an unacceptable level by combining all regions other than USI into a super region. The diversity benefit to smaller EDBs within the super region is much greater, especially in winters where peak loading levels are driven by cold fronts that progressively track up the country, affecting one region at a time.

The reduction in chargeable demand with this super-region (hypothetically using 100 highest loadings as the counterfactual) can be observed over previous assessment period loadings. The value impact depends on whether the resulting quantity change exceeds the impact of the corresponding price change, but is always adverse for the USI and Orion when this area is left out of the super region:

Assessment period to 31 August 2014

	100 Highest average of non-coincident peaks (MW)	Interconnection charge ($m)	Super region coincident peaks for UNI,LNI & LSI	Interconnection charge ($m)	Difference ($m)
UNI	1,871.1	207.8	1,854.5	207.7	(0.1)
LNI	1,890.2	209.9	1,880.9	210.7	0.8
USI	994.6	110.4	994.6	111.4	1.0
LSI	968.5	107.5	945.0	105.9	(1.7)
Total	**5,724.4**	**635.7**	**5,675.1**	**635.7**	**0.0**
Orion	570.2	63.3	570.2	63.9	0.6
Revised price	$111.05 /kW/yr		$112.01 /kW/yr		

Assessment period to 31 August 2013

	100 Highest average of non-coincident peaks (MW)	Interconnection charge ($m)	Super region coincident peaks for UNI,LNI & LSI	Interconnection charge ($m)	Difference ($m)
UNI	1,871.4	216.3	1,860.2	216.7	0.4
LNI	1,892.2	218.7	1,880.1	219.0	0.3
USI	997.0	115.2	997.0	116.1	0.9
LSI	960.7	111.0	939.4	109.4	(1.6)
Total	**5,721.3**	**661.2**	**5,676.7**	**661.2**	**0.0**
Orion	579.9	67.0	579.9	67.5	0.5
Revised price	$115.57 /kW/yr		$116.48 /kW/yr		

Assessment period to 31 August 2012

	100 Highest average of non-coincident peaks (MW)	Interconnection charge ($m)	Super region coincident peaks for UNI,LNI & LSI	Interconnection charge ($m)	Difference ($m)
UNI	1,832.6	184.3	1,817.9	185.6	1.3
LNI	1,878.8	188.9	1,864.1	190.3	1.4
USI	983.1	98.8	983.1	100.4	1.5
LSI	1,004.8	101.0	948.3	96.8	(4.2)
Total	**5,699.3**	**573.0**	**5,613.4**	**573.0**	**0.0**
Orion	564.8	56.8	564.8	57.7	0.9
Revised price	$100.54 /kW/yr		$102.08 /kW/yr		

Disadvantage of being singled out from a super-region

The 2012 result shows a significant benefit for the LSI region that we do not consider is acceptable. We do not have the information to assess it, but particularly for smaller EDBs, variation for individual EDBs within each region will be greater than the variation of the overall region.

In its presentation in Christchurch on 10 December 2014, Transpower expressed the view that, in the absence of any compelling reason, the entire grid should be assessed as a single region. We accept that separating out a sub-region that has a particular constraint will more appropriately focus any load response within that sub-region on the times of peak for that sub-region, but we reject the burden of higher charges that a simple separation carries.

We have considered if an adjustment factor could be applied to the quantity to eliminate the disadvantage. We note that the magnitude varies year-to-year, and any factor would need to look at the difference between the contribution to sub-region peak and the contribution to the super-region peak (or the NZ wide peak). However, the very application of such a factor would effectively eliminate any incentive provided by separating the sub-region, because:

- any load response to the sub-region peak by an EDB would reduce the factor by a corresponding amount, and
- an EDB in the sub-region would be incentivised to instead respond to the super-region peak in order to maximise the factor.

We have not identified an alternative that addresses this issue, and it seems incongruous to be charging USI distributors more at a time where our load response has deferred a significant upgrade (yet a significant upgrade has been made in the North Island).

Within the framework of postage-stamp pricing, we consider that the best alternative is to maintain regions that reflect actual groupings of transmission assets and aim to keep these regions roughly the same size.