TRANSPOWER
Keeping the energy flowing

Waikoukou
22 Boulcott Street
PO Box 1021
Wellington 6140
New Zealand
P 64 4 495 7000
F 64 4 495 6968
www.transpower.co.nz

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Electricity Authority
2 Hunter Street
PO Box 10041
Wellington 6143

By email: submissions@ea.govt.nz

Remaining elements of real-time pricing (RTP)

Thank you for the opportunity to submit to the Electricity Authority's consultation *Remaining elements of real-time pricing* published 19 March 2019. We agree with the Authority' expectation RTP will unlock significant benefits through much more reliable price signals for consumers and generators to act on. Consequently, we strongly support the project and its objective to "make spot price signals more accurate and actionable for all decision-makers."[1]

We also support the decision to use engagement groups to develop participant understanding as the project progresses. Transpower as system operator is committed to increased communications and reporting of the technical aspects of the real-time market, including how participants' information will be used in the price formation process.

We have responded to the Authority's specific questions about the remaining design elements in the appendix to this submission. The body of our submission below focuses on some wider implications arising from a change to RTP from grid owner and FTR manager perspective. We anticipate these will be addressed by the Authority and system operator in the next phase of the project.

Real-time price formation relies on quality data from meters

Under RTP, real-time prediction of demand will be a critical input to final price formation, with the primary data input being metered demand at each GXP. Currently the system operator's real-time demand prediction is a top down method using metered generation data as the primary input.

For the proposed new approach for RTP, which we support, the system operator will take the grid owner's net demand values from its ION meters, and (when necessary) use data received from offered embedded generators to create a gross demand prediction in real-time.

With that new context we make the following Code-related points.

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[1] Authority Consultation Paper: Remaining elements of RTP March 2019, page ii

The nature of demand data to be provided should be defined in the Code

The Code should define that the demand data that is provided by the grid owner's meters is for net demand. Accordingly, we propose drafting to better convey policy intent for providing real time demand values from the grid owner's assets:

Transpower proposed clause 13.69AAA

13.69AAA Grid owner to provide real time demand values to system operator
Each **grid owner** must, to the extent practicable, use its <u>grid revenue meters</u> to provide to the **system operator** real-time <u>net</u> **demand** values (in **MW**) for each of its **GXPs** for the purpose of ~~that are required by the **system operator** to calculate the expected profile of **demand** under~~ clause 13.69B (3)

Reliable, accurate ION meter data is dependent on supporting infrastructure

Under RTP the grid owner's SCADA infrastructure will play a critical role in delivering reliable, accurate data from the ION meters to the system operator's market systems in real-time. The level of reliability required from the grid owner's supporting infrastructure is not addressed by the proposed Code drafting. We consider consequential investment in grid owner supporting infrastructure <u>may</u> be required, along with a mechanism to allow the grid owner to recover the cost of that investment.

During the next phases of the RTP project we expect the interface between grid owner and system operator systems and processes will be considered in detail. For example, how to configure control and monitoring systems to flag when potential metering issues are detected and/or trigger a switch to back-up metering systems.

RTP changes removing data and information obligations may have adverse implications outside pricing processes

In our view, proposals to remove data and information obligations attached to the existing pricing process may have adverse consequences for other existing and potential information processes. For example, the obligation for embedded generators to provide injection information to the grid owner is removed by RTP, but we use that information to create gross load forecasts for system planning. The injection information provision may also be needed for anticipated future policy under Additional Consumer Choice of Electricity Services (ACCES).

Where RTP will no longer require specific data or information for pricing processes, the Authority should establish what other industry processes are reliant on that data or information before removing obligations on participants to provide it.

Consequential change to the FTR market and LCE allocation

We note the change signalled by the RTP presentation[2] for Loss and Constraint Excess (LCE) to be allocated from dispatch schedules, which will require consequential change to Financial Transmission Rights (FTR) market systems and processes. We consider the changes are an opportunity to seek operational

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[2] RTP presentation (slide 13) states "Loss & constraint excess apportioned from dispatch schedules"

efficiencies associated with allocating LCE for FTR settlements, and allocating residual LCE to market participants.

With 3 new hubs added in June 2018 the FTR grid now more closely approximates the whole grid and LCE across the FTR grid is close to 90% of all LCE. We consider an efficient consequential change would be for the clearing manager to allocate LCE for FTR settlements to the FTR manager, and residual LCE directly to purchasers alongside other market reconciliation and clearing processes.

In our view the growth of the FTR market means Transpower's involvement in allocating residual LCE is unnecessary and inefficient.

In our role as system operator we look forward to developing and implementing RTP and are confident we have the resource and expertise required to do so. We note Transpower "may have limited ability to respond to any other proposals for material system change that might arise in parallel."[3]

Finally, we commend the positive engagement between the Authority and system operator to date on this substantial and exciting project, and look forward to continuing collaborative development between all parties going forward.

Yours sincerely

Rebecca Osborne

Regulatory Affairs and Pricing Manager

[3] Transpower submission to Authority consultation on RTP, October 2017.

Appendix - Responses to Questions

Question	Response
1. Do you agree with our proposed criteria for distributed generation to be eligible for dispatch-lite? If not, please explain your reasoning	We defer to industry participant response.
2. Do you agree with our proposed criteria for purchasers to be eligible for dispatch-lite? If not, please explain your reasoning	We defer to industry participant response.
3. Do you agree participants providing SCADA telemetry should be eligible for dispatch-lite? If not, please explain your reasoning	We defer to industry participant response.
4. Do you agree combining an acknowledgement response via the dispatch system with an obligation to immediately rebid or reoffer is the best design option? If not, please explain your reasoning	We defer to industry participant response.
5. Do you agree gate closure for all dispatch-lite participants should be set at 30 minutes (one trading period), the same as for current embedded generators?	We defer to industry participant response.
6. Do you agree with the proposed compliance arrangements for dispatch-lite? If not, please explain your reasoning.	We defer to industry participant response.
7. Do you agree with the proposed method to allow dispatch-lite participants to withdraw from dispatch? If not, please explain your reasoning.	We defer to industry participant response.
8. Do you agree we should implement dispatch-lite as part of RTP, should we decide to proceed? If not, please explain your reasoning.	We defer to industry participant response.

9. Do you agree reserve pricing under RTP should place a higher cost on scarcity of FIR than scarcity of SIR? If not, please explain your reasoning.	Yes. We consider FIR has greater value in arresting frequency collapse so the higher cost on scarcity of FIR should incentivise FIR provision.
10. Do you consider the risk violation curve approach would increase incentives or opportunities for gaming? Please explain your reasoning	We defer to industry participant response.
11. Do you agree we should implement the risk-violation curve we have described to handle reserve shortfalls under RTP? If not, please explain your reasoning.	We support a configuration that reduces the risk of demand management measures.
12. Which configuration of the risk-violation curve do you consider we should adopt? Please explain your reasoning	We support a configuration that reduces the risk of demand management measures.
13. Should we set a total reserve shortfall quantity limit if we implement the risk-violation curve under RTP? Please explain you reasoning.	No. We consider the current industry-preferred practice should continue i.e. to redispatch all spinning reserve as energy and rely on interruptible load and AUFLS to manage a contingent event during a shortfall.
14. Do you agree a new type of formal notice to cover periods of reserve shortfall under RTP is not warranted? If not, please explain your reasoning.	We defer to industry participant response.
15. Do you agree with the proposed methodology to calculate the scarcity pricing values? If not, please explain your reasoning	Yes.
16. Do you agree the Authority should have an obligation to review the scarcity pricing values at least once every five years? If not, please explain your reasoning.	We agree with an obligation to review but consider any changes arising (with changed values) should not be so frequent that the market loses an ability to forecast. We note the figures being used are already based on information from 2011 so future changes to scarcity values may also endure longer than the review cycle.
17. Do you agree with the objectives of the proposed amendment? If not, why not?	Yes.

18. Do you agree with the objective of the proposed Code amendment? If not, please explain your reasoning.	Yes, but we consider clause 13.69AAA should be more specific about the provision of demand values from the grid owner's meters. We have proposed re-drafting in the main body of this submission.
19. Do you agree with the cost benefit assessment?	Yes.
20. Do you agree with our assessment of alternatives? If not, why not?	Yes.
21. Do you have any comments on the drafting of the proposed Code amendment?	Yes. In the body of this submission we have: - Proposed re-drafting of clause 13.69AAA to be more specific about the nature of the demand data required to be provided from the grid owner's meters. - Identified that the level of reliability required from grid owner's supporting infrastructure is not addressed by the proposed Code drafting. - Suggested that where RTP will no longer require specific data or information for pricing processes, the Authority should establish what other industry processes are reliant on that data or information before removing obligations on participants to provide it. For example, the obligation for embedded generators to provide injection information to the grid owner is removed by RTP, but we use that information to create gross load forecasts for system planning. The injection information provision may also be needed for anticipated future policy under Additional Consumer Choice of Electricity Services (ACCES).