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Sent via email: distribution.feedback@ea.govt.nz 28 February 2023

Updating the regulatory settings for the Distribution Networks

We appreciate the opportunity to respond to the Authority's issues paper *Updating the regulatory settings for the Distribution Networks* published 20 December 2022.

This consultation continues the Authority's policy thinking from its earlier discussion paper[1] and proposes a range of potential interventions mainly impacting Distributors. We consider the ideas in the paper have implications and benefits to more parties than those discussed directly, i.e. system operator, grid owner, and consumers.

Our main submission points under the earlier discussion paper remain relevant:[2]

- Visibility of Distributed Energy Resources (DER) is necessary for:
  - understanding the potential for procuring flexibility services as energy and ancillary services (as System Operator) or as non-network alternatives (as Grid Owner)
  - operational activities such as network planning, outage planning and assessments, understanding and predicting power system behaviour, and load forecasting
- Transpower is keen to work constructively with the Authority and other parties on a standard contract for flexibility services.[3]

Distributed Energy Resource definition and visibility

We agree with the Authority that there is debate about how to define terms for distributed energy resource (DER). The definition of DER as currently described - "*small-scale,*

[1] Updating the Regulatory Settings for Distribution Networks (ea.govt.nz)
[2] Transpower-Updating-the-Regulatory-Settings-for-Distribution-Networks.pdf (ea.govt.nz)
[3] Noting – as we indicate in this submission – that our own needs for transmission alternatives are likely to be too bespoke for a standard contract.

distribution-connected assets that either reduce load or export more power" - could apply to any load that is simply switched off by the consumer at home, such as a TV or lighting, and is too broad.

We encourage the Authority to review its definitions to ensure that they are internally consistent and that there are no unintended capture of technology/ equipment within its definitions:

- The Authority refers to intermittent generation as not being controllable. We consider that intermittent generation *can* be controllable, as is illustrated in Australia. Distribution networks, by agreement, can prevent solar PV from exporting
- The Authority's definition of DER states that "*DER can also include front-of-meter **small** generation or storage located in lower-voltage parts of the network*" [emphasis added]. However, the Authority definition states that distributed generation (DG), which covers large generation, is a subset of DER. These definitions are not consistent.

The imminent implementation under RTP[4] for demand flexibility and DER to be more visible in the wholesale market will cumulatively create effects at grid level. We consider that as DER penetration increases, real-time data processes would need to show aggregate DER of 1MW or greater, at a network supply point level, although not immediately. This information would enable the system operator to produce better load forecasts, improve outage planning, and subsequently enable more efficient actions from participants.

Role of transmission alternatives (aka non-network solutions)

We support the Authority liaising with the Commerce Commission about matters within the Commission's jurisdiction for investment decisions and efficient expenditures for electricity networks. The Part 4 incentive regulation provides for investment decisions to account for network and non-network (i.e. procuring third-party service) options.

Our needs for transmission alternative contracts are bespoke; for example, technical requirements might be specified in a very different manner for a battery vs. an embedded hydro plant providing voltage support. For major capex projects, we seek to optimise the volume of services required under the project which means a bespoke event frequency and duration based on the load forecast and region of interest.

However, through funding under Regulatory Control Period 2015 – 2020 (RCP2), Transpower developed significant experience through trials and pilots to procure and activate demand response. As we submitted to the previous discussion paper[5] we are open to working constructively with the Authority and other parties on developing understanding on the form for a "standard contract."

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[4] Market Brief 14 February 2023 "*The system operator is busy preparing the technical details for dispatchable demand and dispatch notification to go live on 27 April 2023. After this date participants will be able to bid and offer their demand flexibility and distributed energy resources into the wholesale market."*

[5] Transpower-Updating-the-Regulatory-Settings-for-Distribution-Networks.pdf (ea.govt.nz) "*In Transpower's work with IPAG, we proposed that a standard contract should be developed with other parties that have procured flexibility services. Transpower is open to working constructively with the Electricity Authority and other parties to deliver this.*"

Transpower supports the Authority's position to "*seek to encourage the provision and implementation of flexibility services without precluding distributors from these activities at this stage.*[6] Allowing in-house options may be more efficient than procurement.

Data access

Access to data is critical for supporting operational and investment understanding in the transition to a highly renewable energy system with increasing two-way flows. We support actions to improve access to consumption data for network needs and new services. The Authority needs to be clear on who owns that data, and what permissions (i.e. from the consumer) are required for the data to be accessed by other parties. We also note that the Authority should consider all other sources of data when undertaking the cost benefit analysis of its proposals, for example inverters with communication links can provide distribution networks' DER operational data.

We encourage ICP-level data aggregated to grid level be passed on to system operator and grid owner for grid operations and planning, each as a permitted purpose. This data visibility will lead to better long-term outcomes for consumers.

Finally, in footnote 89 the Authority state "*whether the metering and information provision requirement should apply irrespective of whether a DER injects energy into the network or whether the energy is consumed behind the ICP meter*" by taking measurements down to 0.1MW instead of the current 10MW. We understand the idea is for a potentially more accurate *gross load* allocation of the residual charge under the TPM, based on measuring the "*gross anytime maximum demand*" load. We appreciate that the Authority will consult on this further if it decides to take the proposal forward, however we have initial concerns about the additional costs imposed on consumers and the potential disincentive for consumers to install DER.

We have responded to select questions, in the appendix.

Yours faithfully,

Joel Cook
Head of Regulation

[6] Para. 1.8

Appendix A – Response to questions

Question	Transpower response
Q1. Do you see value in commissioning two separate reviews to look into the merit and practicalities of implementing the recommendations of the UK's Energy Data Taskforce around unlocking the value of customer actions and assets and delivering interoperability in a New Zealand setting?	We are cautious about the merit of reviewing a report derived in a specific overseas context (the UK), to gauge opportunities to translate recommendations to the NZ context. Recommendations are unlikely to be "cut and paste" given differences between respective markets, government policy, and institutional structures. The National Electricity Market in Australia could be a better starting point for understanding the opportunities and risks under a digitalisation objective. Australia already has a mature energy data platform which covers data requirements for DER and distributors.
Q6. Do you agree that the Authority should amend the Data Template to address the above issues to improve its workability? If not, why not?	For historic reasons Transpower is an MEP for just 3 ICPs, so as we are not subject to the Data Template under Part 12A. We would make the data available through grid owner reporting tools, if asked for it.
Q17. The Authority acknowledges that definitions of 'real-time' vary, please explain what real-time data means to you.	Depends on the data attribute being measured and its use. Forecast data under RTP in the market is five minutes but power attributes (frequency, voltage) are much shorter timescale sub-second. Real time data for the system operator means instantaneous (or close to).
Q23. Do you agree that visibility of the location, size, and functionality of larger DER needs to be improved within the next 3–7 years to help understand the drivers of network congestion, what DER is 'controllable', and what services could be offered to owners of DER? If not, why not?	Yes, maybe sooner. We estimate the Electric Vehicle fleet already has a cumulative ~230MW capacity, subject to assumptions about how much of that is made available. ICP-level data aggregated to grid level would need to be able to be passed on to system operator and grid owner for grid operations and planning, each as a permitted purpose.

Q25. Do you think that the Authority, instead of a DER registry, should consider amending the registry data fields and / or requirements to improve DER visibility?	We agree, assuming the registry can be efficiently upgraded for such functionality to cover more DER including DG. An authorised party should be able to run a report from the registry database drawing on that static information to create aggregate data. Only DER that is offered by the customer needs to be recorded and would include excess generation that is injected back into a network (either reimbursed or gifted). Aggregate DER information could be made available the same way that DR is on EMI. We note that Distributed Generation capacity is already captured in the registry. FYI, Transpower as grid owner receives monthly data of DER *operation* (kWh volume) across distribution networks, for the TPM; but that information does not provide capacity.
Q29. Do you agree that model privacy disclosure terms would facilitate data access?	Disclosure terms would first need underpinning processes to ensure consumer consent for third-party access the consumer's consumption data.
Q30. Do you see any practical issues with this proposal?	As above.
Q32. Would the industry find it helpful for the Authority to conduct workshops on privacy preserving/minimisation techniques?	Yes. As consumers are unlikely to be visible in this submission process, we consider the Privacy Commissioner could be invited to provide a view on the data provision approaches proposed by the Authority.
Q31. What are your views on the three options presented above, to deal with Issue 1 (that distributors might prefer network investments to NNS)? What alternative option/s would you favour, if any?	Investment decisions and efficient expenditures are the jurisdiction of the CC and we support the Authority engaging with the CC on this matter.

Q32. Do you agree with the tentatively preferred intervention to deal with Issue 2 (Option 3: encourage standing offers) and the collection and monitoring of information proposed under Option 4? If not, what alternative option/s would you favour, if any?	We agree with the (lack of) innovation risk from standardisation identified (refer 7.29 – 7.33) and that the Authority considers that there is no issue to address now. Nevertheless thorough previous engagement with the Innovation and Participation Advisory Group (IPAG) we proposed that Transpower is open to working constructively with the Electricity Authority and other parties on a standard contract.
Q33. Do you think there are circumstances in which the Authority should extend the arm's length rules? If not, why not?	Not without evidence of a problem. The Authority "*acknowledges the need for care with the timing of this option, as some distributors have submitted that they struggle to get fit-for-purpose flexibility service offerings from third parties*."
Q37. Do you agree with the proposed approach to monitor progress between Transpower and distributors in developing standard offer forms for procuring NNS, and monitor whether issues associated with operating agreements for flexibility services are developing, and prioritise resource to progressing the other chapters? If not, why not?	This policy area falls under the jurisdiction of the CC and - for connection assets - the Benchmark Agreement. Thorough previous engagement with the Innovation and Participation Advisory Group (IPAG) we proposed that Transpower is open to working constructively with the Electricity Authority and other parties on a standard contract. Using our trial experience with third-party services procurement, we are actively supporting the Flex Forum by sharing our procurement process, including participation agreements, programme structures and flex management system. Our support was extended to offer our distributed energy resource management platform *FlexPoint*™ to support the EECA and EEA OpenADR project (Demand Flexibility Common Communication Protocols), where three participating EDBs have elected to use FlexPoint™.
Q38. Do you have any views on the best way the Authority can monitor whether issues associated with operating agreements for flexibility services are developing?	We support the Authority's conclusion that "*this [progress on operating agreements] should occur and will monitor progress, but at this time will not mandate it*." (para. 7.3)

Q39. Do you have any suggestions for how the Authority can support industry-led work on providing guidance on best practice and templates for operating agreements?	We would be happy to provide our standard participation agreement developed through our demand response trials, as a starting point.
Q40. What are your thoughts on the proposed scope for the Part 6 review? What, if anything, would you include or exclude, and why?	The scope needs to consider links with common quality (Part 8). As DER penetration increases, we consider a minimum of 1MW *aggregated* DER needs to be made visible for system operator, and for grid owner. If DER becomes sufficiently large that the distributer requires technical input from Transpower, the response timeline for larger-scale DER needs to recognise the additional investigation effort required. Consideration of the interaction between clauses 6.3(2) and 13.9A(1) as they pertain to an embedded generator offering into the wholesale market. Specifically, how, and by whom, should distribution congestion impacts be accounted for in the quantity being offered. Uncertainty could lead to inefficient outcomes were available generation 'under-offers' or conversely could lead to insecure and inefficient operations with unavailable generation 'over offering' capacity.
Q42. What are your thoughts on amending Part 6 of the Code to explicitly include DER, and what do you think are the key issues to be considered?	Consistency across the Code. Batteries classified as generation by the Broadening Definitions of Generating Unit and Intermittent Generating Station (2020) Code amendment. It is not immediately apparent why the location of a battery would impact on this definition? Ensuring the processing timeline for large DER connections (>1MW) recognises that input may be needed from Transpower.

Q46. What are your thoughts on maintaining the current approval timeframes in Part 1 (comprehensive) and Part 2?	Approval timelines will need some flexibility for larger DER connections (>1MW) that may require input from Transpower.
Q51. Should the AS/NZS 4777.2:2020 Standard be mandated for inverters in New Zealand? If so, how should this be accomplished?	Yes although mandating a single standard could be restrictive – drafting could permit **minimum** AZ/NZS 4777.2:2020 or a modern equivalent (i.e. from other jurisdictions) or newer equipment surpassing the requirements of the standard. AEMO describes that the updated AS/NZS 4777.2:2020 delivers new performance capabilities and requirements that are in-line with international best practice to support secure power system operation with high levels of DER penetration. An advantage is that the inverter can communicate operational and locational information for the DER instead of relying on a smart meter. EDBs may not be able to enforce the standard's use if the Work-Safe wiring regulations are not also updated. WorkSafe could update its advice on how to consider AS/NZS 4777.1 and 4777.2 in light of any Code references.[7] Another potential route could be via Parliamentary Counsel under its Legislation Act 2019 [8] which has as a purpose "*provide(s) tools for modernising and simplifying legislation and keeping legislation up to date.*"

[7] https://www.worksafe.govt.nz/laws-and-regulations/regulations/electrical-regulations/regulatory-guidance-notes/regulatory-application-of-asnzs-4777/
[8] Legislation Act 2019 No 58 (as at 30 November 2022), Public Act – New Zealand Legislation