Orion

10 March 2023

The Electricity Authority

Wellington

New Zealand

Email: distribution.feedback@ea.govt.nz

Feedback on Issues Paper: Updating the Regulatory Settings for Distribution Networks.

Introduction

1. Orion appreciates the opportunity to submit on the Issues paper where the Electricity Authority (the Authority) is seeking feedback on Updating the Regulatory Settings for Distribution Networks from industry stakeholders.
2. The Issues Paper[1] included a list of questions regarding the regulatory settings on which the Authority is seeking feedback.
3. Note that the original submission date for this was set at 28 February 2023 with an extension of 14 days due to Cyclone Gabrielle.
4. Orion's feedback[2] to the Electricity Authority on 28 September 2021 is also relevant to this feedback. There appears to be some duplication in this feedback requested by the Authority.
5. We reiterate the following points from Orion's previous feedback which are relevant to this issues paper:

[1] https://www.ea.govt.nz/assets/dms-assets/31/Issues-paper_-Updating-the-regulatory-settings-for-distribution-networks-December-2022-v2.pdf

[2] https://www.oriongroup.co.nz/assets/Company/Submissions/Orion-response-to-EA-EDB-regulatory-settings-improving-competition-and-supporting-a-low-emmissions-economy-Sep21Final.pdf

- Orion submits it is important to avoid prescribing solutions or outcomes too soon given some of the fundamental uncertainties that remain on the likely speed of uptake of technology by consumers and the exact nature of the technology that will be implemented and how it will be utilised.
- The Authority should be cautious about an early move to regulation that could ultimately hinder the future that the Authority and New Zealand desires when there is lack of clarity in future developments. This is more likely to result in higher costs for our customers and potentially hinder New Zealand's efforts to decarbonise. We note that the Authority has acknowledged this in point 2.58 of the Issues Paper, that adopting a 'least regrets' approach will avoid regulatory barriers in the future.
- The Authority appears to suggest that moving to a contestable market for DER is a priority. We would suggest, broadly speaking, a staged approach to this would be more appropriate, as DER scale grows over time. This provides us time to get this right.
- Stage 1 of any attempt to unlock the value of DER, and the stage we believe should receive the most initial focus, is targeting capture of 85% of the 'DER value stack' – namely peak load reduction. *The regulations also need to be flexible enough with a future focus in our progression to 100% renewable generation. This progression starts with identifying innovations, exploring options, and trailing the options, aligning viable options, and then regulating DER once there is clarity and certainty. This will avoid any unintended consequences of putting regulations in place too early .*
- We submit that it is premature for the Authority to apply prescription or mandate approaches and standardisation for operating agreements in the short term. This market is emergent and so time needs to be given for exploration and flexibility to try these solutions out and capture learnings. We are open to non-network alternatives and are seeking to improve our transparency about where constraints exist in service of identifying economic solutions that can provide the appropriate level of service compared to traditional solutions. *Orion is not only open to Non-network Solutions but actively seeking to support growth of NNS. This is to maximise the scope of participation and support our strategy of "flexibility first" in our investment approach.*

Summary

6. We have reviewed the Issues Paper request which was published on the Electricity Authority's website.
7. Orion considers that updating Part 6 of the Participation Code[3] to include DER and pricing in Schedules 6.4 and Schedules 6.5 as well as data sharing capability should be a priority for updating the regulatory settings.
8. We note that the Authority released its final decision[4] on Code amendments on enabling energy storage systems in March 2022. We submit that the decisions made are also incorporated when updating regulatory settings for distribution networks.
9. We acknowledge that the Authority also has workstreams such as the Future Security and Resilience (FSR)[5] programme which has timelines that may cross over to the work being done on Updating the regulatory settings.
10. Orion considers that pre-empting regulation can result in unforeseen consequences when the market is still in its infancy and developing. We acknowledge that markets such as the United Kingdom and Australia are more advanced than New Zealand and that we should review these in our research when developing regulations. However, we recommend that it would be better to form our own local taskforce in conjunction with industry participants such as IPAG (possibly continued as a sub-group of the proposed EAAG), FlexForum and ENA's Future Networks Forum which plays a role in research and collaborative innovation between EDBs, in developing suitable regulations for the New Zealand electricity market. Regulations which are not fit for purposes will stifle innovation.
11. Collaboration across the value chain will de-risk and reduce the likelihood that regulation will not be appropriate or fit for purpose for all participants in the electricity market.
12. EDBs (Electricity Distribution Businesses) collaborate where practical, as we do not compete, and share our learnings as far as possible. This is evident through Flexforum (cross-sector collaboration on DER and Flex) and ENA's Future Network Forum (driving innovation approaches between EDBs).

[3] https://www.ea.govt.nz/assets/dms-assets/9/9898Electricity-Industry-Participation-Code-1Nov10.pdf
[4] https://www.ea.govt.nz/assets/dms-assets/29/Enabling-energy-storage-systems-to-offer-instantaneous-reserve-Final-Decision-paper.pdf
[5] https://www.ea.govt.nz/assets/dms-assets/30/SRC11-Future-Security-and-Resilience-FSR-update.pdf

13. We do not consider that the Electricity Authority should intervene in joint venture arrangements, arm's length transactions or commercial arrangements / model's frameworks at such an early stage, given there is still significant development to occur in these areas of the sector. Arm's length transactions are already addressed for EDBs, in the Commerce Commission's information disclosure requirements and related party transaction provisions[6].
14. We submit that the interchangeable use of Non-Network Services (NNS) and flexibility throughout the Issues Paper is confusing. A NNS can include solutions such as dynamic line ratings, operating envelopes, or network configurations. These are distinct from flexibility services and require separate market settings.
15. We submit that Market models (e.g. TSO/DSO roles) need to be clarified in the medium term to drive consistency, efficiency, and collaboration.
16. We submit that market development requires industry to explore, align and then regulate. The first two being led with direction from the regulators, followed by regulation at the appropriate time.
17. We submit that while additional DER uptake occurs, we also need to ensure that hot water control is not relinquished in the short term under the DDA (Default Distributor Agreement) as this has always been used for demand side management for networks. Hot water control is dealt with in the DDA, and it will require more care to mitigate the risks of being market-led as opposed to other DER solutions such as EV's and batteries. Distributors and industry reviews have on several occasions reiterated that hot water control is vital for system load management and deferral of investment and hence it must be carefully managed in a transition. As an example, after a grid emergency was declared in August 2021, hot water ripple control was key to stabilising the grid. Consequently we consider that it is essential that the EA consider separately, and be more adverse to large scale immediate change on, the issue of hot water DER compared to other DER like batteries.

Other Feedback

18. In principle, Orion supports the Electricity Network's Association's submission.

Feedback Regulatory Settings for Distribution Networks

Orion's responses are included in Annexure A of this document.

[6] https://comcom.govt.nz/regulated-industries/input-methodologies/input-methodologies-for-electricity-gas-and-airports/related-party-transactions-provisions

Concluding Remarks

Thank you for the opportunity to provide feedback. We do not consider any part of this feedback as confidential.

If you have any questions or queries or aspects of the submission which you would like to discuss, please contact me on 03 363 9898.

Yours sincerely

Rob Tweedie

Regulatory Manager

Orion

Appendix A:

Submitter: Orion Group

**The headers refer to the relevant sections in the issues paper*

4. Equal access to data and information

The following points on the discussion contained within the issues paper are relevant to the issue of equal access to data and information:

Paragraph 4.3 – we believe the type of information that the Authority lists at paragraph 4.3 will be required by distributors in the short term (the next five years) rather than the Authority 's position of the medium term (the next five to ten years). Orion is already endeavoring to gather this information from metering providers as we recognise the importance of it now.

Paragraph 4.4 - we believe the type of information that the Authority lists at paragraph 4.4 will be required by distributors in the medium term (the next five to ten years) rather than the Authority's position of the long term (beyond ten years). The Authority may wish to put on its list of activities to pursue in the 3–5-year timeframe how it can encourage metering providers to be able to provide real time information.

Paragraph 4.5 – we believe that not all information that distributors require will be required by flexibility traders. The Authority should not simply progress down the path of assuming information needs are the same as such an assumption may ultimately increase costs to customers. We suspect this is an area that the Authority may wish to pursue in workshops with distributors and flexibility providers or seek guidance from one of the bodies established by industry to examine how flexibility uptake can be encouraged.

Table 2 – Point 5 in relation to transparency of MEP pricing is not a high priority. In our negotiations with MEP providers to date we have found their pricing to be reasonable and given the breadth of issues the Authority could be examining in the next 5 years we don't see this area as being critical. We suggest the Authority downgrade it to something to be examined in the medium term.

Table 2 – Point 6 and 10 in relation to distributors and flexibility traders having better visibility of DER. We believe this should be an issue that is upgraded by the EA from Medium to High. For some DER once installed there will be little chance of knowing it's characteristics as it is not recorded in a central database, like the registry. Any new regulations around DER visibility are only likely to apply to newly installed DER post the regulations start date. Consequently, if regulations/visibility is not introduced until 5-10 years, we will miss out on capturing DER visibility sooner.

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Table 2 – point 9 in relation to flexibility traders not having access to granular LV congestion data. We believe this could be downgraded from high to medium. Distributors, like Orion, which do not own their meters are not able to obtain smart meter non-consumption data. This is a barrier on our flexibility journey and Network Transformation Roadmap. We recommend that this be a high priority for the Authority to allocate resource to resolve this.

We also note the following regarding Table 2:

- We suggest including shorter timeframes e.g., 1-2, 3-4 and 5+ years to support a more granular prioritisation.
- We consider the highest priorities should be 2, 3, 6.

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?***

Answer: No, while the digital spine concept could work, we still support the introduction of an application programme interface (API) as detailed in our previous submission (Page 8 Appendix A) which is similar to a digital spine concept and provides more transparency for industry participants.

The UK jurisdiction is quite different from New Zealand and has been evolving over the last 10 years. The Authority should review its approach to creating its own Taskforce and engaging with industry groups to develop recommendations for the NZ Electricity Market. We also suggest that the Authority take a similar approach to the UK and allow the market to evolve through exploration, and an industry led convergence before standards and legislation are implemented. Engaging with industry workgroups such as IPAG and FlexForum will de-risk the Authority's potential of prematurely setting regulation incorrectly.

Predetermining how the market may evolve and prematurely forming regulations will restrict innovation, future flexibility and not provide time to design appropriate regulations suitable for New Zealand.

Q2. ***Does this capture the key data needs for distributors to make informed business decisions that will unlock the potential of distributed energy resources (DER) for the long-term benefit of consumers?***

If not, what data is missing and what would it be usedfor?

Answer: Yes, to be able to plan and build for network resilience this, in conjunction with EV (Electric Vehicle) charger identification would be helpful for network management purposes. Near-real time data would also be helpful if it is in half-hour and 5-minute intervals.

We note that the Authority rates priority to data as medium under point 4.58. Orion recommends that this is a high priority to enable DER visibility as this is not easy to predict and forecast. Early issues and clusters have a disproportionately high impact on networks due to the lack of diversity. Issues arising from this could impact public trust and slow down decarbonisation. It is important that we remain ahead of the 'S curve' of technology adoption as it takes time to procure flexibility services and implement network upgrades. Without early visibility and identification of trends through access to data, networks risk becoming a bottleneck.

However, we do not agree with the Authority's statement that DER is currently minimal, visibility and observability is high, indicating that there is uptake of DER occurring. We have submitted on this point before, LV visibility is not as transparent due to limited access to disaggregated meter data nor registry fields to record DER.

Industry needs to be given the opportunity to develop. This will allow for divergence of DER technologies before converging and consolidating how the industry has transformed in order for "fit for purpose" regulation to be applied. Other jurisdictions such as the UK are far more mature than the NZ electricity market and it is important for NZ to learn by doing through industry forums such as the FlexForum and ENA working groups.

Q3. ***Do you agree with the prioritisation of the key data needs for distributors? If not, why not and how would you suggest the priority is changed?***

Answer: Yes, we agree with the prioritization subject to our previous comments that access to real time smart meter data and improved DER visibility needs to be given a higher priority by the EA. The more visibility distributors have on their network about congestion and power quality, the better they can forecast planning of flexibility services, replacement, renewal, and system growth. The flexibility market development should not be hindered by distributors not having the appropriate visibility on the network.

Q4. ***Does this capture the key data needs for flexibility traders to make informed business decisions that will unlock the potential of DER forthe long-term benefit of consumers? If not, what is missing and whatwould the data be used for?***

Answer: Yes, subject to the following points:

- Point 4.62 refers to flexibility traders being in a position to identify network capacity and problems. Without a deep understanding of the network, it is unlikely that flexibility traders will be in a position to identify network problems, nor is this their role . They will be looking at ways to maximise value across multiple value streams, including the spot market.
- Point 4.68 says access to real time data is less of a priority for distributors. We agree that up to the minute data is less of an immediate priority but access to data is a high priority. This supports ongoing investment and modernisation of network systems such as connectivity models (which are not static e.g., change in real time as the network is reconfigured), power flow analysis, etc. This capability will require significant investment to enable visibility. Once available, we support making this insight available to flexibility traders and other stakeholders.

Q5. ***Do you agree with the prioritisation of the key data needs for flexibility traders? If not, why not?***

Answer: Yes, we agree subject to the following points:

- Point 4.64 is not a high priority within the next 1-3 years. Firstly, distributors need to be able to access the data and develop their network forecasting models etc., to be able to identify LV constraints and identify where flexibility solutions are needed. Flexibility traders having access to this data in the next 1-3 years is therefore not likely needed and quite simply unlikely to be able to be comprehensively provided.

- Point 4.66 talks about access to data being a medium priority and aligning with the FSR. We believe it should be a high priority for visibility of larger DER assets, similar to the UK with an embedded capacity register.

- In respect of point 4.67, it is not necessarily the flexibility traders who need to understand the real-time pressures on LV-networks but rather distributors. It is reasonable that flexibility traders would want to see consumer consumption data to evaluate their offering to consumers as well as align these offerings with market prices to leverage the best spot market pricing margins.
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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?***

Answer: Yes, it makes sense to include the ENA (Electricity Networks Association) / ERANZ data template to improve the workability as this has already been consulted on and agreed upon in principle between distributors and retailers.

Q7. ***Are there other changes to the Data Template that would improve it and assist it to be a useful mechanism for open access to data?***

Answer: No, not at this stage however we recommend that the Authority considers the longer-term changes which the Consumer Data Right (CDR) will have in the electricity sector when making changes to the Data Template. Referring to points 4.73-4.75, the Authority refers to the CDR[7] and work which MBIE has undertaken in its Regulatory Impact Statement and note that it will probably not be rolled out to the energy sector before 2026. However, when it is rolled out, it will mean that the Electricity Industry Participation Code 2010 will need to be reviewed as there will be a double-up in provisions that will need to be resolved.

Q8. ***Do you agree that this is an issue? If not, why not?***

Answer: Yes, it is an issue and adds transaction costs. A balance needs to be struck in respect of Privacy of Information, using information for network management and flexibility without compromising retail competition.

Q9. ***Should the Authority amend the Code to clarify that MEPs can contract directly and provide both ICP (Installation Control Points) data to distributors (and flexibility traders) for permitted purposes? If not, why not?***

Answer: Yes, distributors have found it challenging to obtain un-aggregated data making LV visibility and monitoring challenging. If MEPs can directly contract with distributors and flexibility traders, this would resolve a lot of complexity currently experienced when trying to access metering data.

Q10. ***Should the DDA Data Template be updated to include Power Quality Data? If not, why not?***

Answer: It makes sense to leverage the new technology in metering to improve network performance

[7] https://www.mbie.govt.nz/dmsdocument/15545-regulatory-impact-statement-establishing-a-consumer-data-right-proactiverelease-pd

by including Power Quality. These supports being able to have visibility at ICP level specifically with increasing DER uptake.

However, Orion believes that Power Quality Data is not consumption data where the terms and conditions should be negotiated between retailer and distributors. The current data template is also a lot more onerous than what we would expect to negotiate with MEPs.

Q11. ***Do you think that the transaction costs associated with negotiating access to MEPs is a problem that the Authority should prioritise? If no, why not? If yes, do you think there is merit in developing a template to help reduce transaction costs?***

Answer: No, Orion does not believe that this is an area which the Authority should prioritise as negotiations need some level of flexibility. Our experience is that there is minimal cost associated with negotiating with MEPs, and we are not convinced that developing a standardised default template will achieve the goal of reducing costs – it would likely increase costs based on our prior experience with default templates. The key challenge is not the costs associated with negotiation, but rather the time taken for MEPs to be able to provide the data.

Q12. ***Do you agree that MEP pricing for ICP Data (including Power Quality Data) and related data services is not unreasonable at this stage? If not, why not?***

Answer: *In our negotiations with MEP providers to date we have found their pricing to be reasonable. Given the breadth of issues the Authority could be examining in the next 5 years we don't see this area as being critical.*

Q13. ***Do you agree that MEP pricing for the provision of ICP Data to distributors (and other parties) could be more transparent? If not, why not?***

Answer: Yes, transparency would speed up the process of consistent and standardised pricing. Publishing these prices would also make assist in standardizing, or at least allowing for negotiating charges from MEPs even though we consider the current pricing from our MEP as reasonable.

Q14. ***To support the transparency of pricing, standardisation, and equal access to data, do you think that the Authority should consider further implementing IPAG's Input Services recommendation that MEPs publish standard 'pay-as-you-go' terms open to all parties? If yes, why and what do you think this could cover? If not, why not?***

Answer: Yes, we support the recommendation for MEPs to publish standard 'pay-as-you-go' terms.

This would enable users to negotiate and ensure a level playing field for all potential purchasers. e.g., It should at least cover standard pricing on obtaining aggregated consumption data at a price per ICP and other miscellaneous charges. We see this as an issue the Authority could progress in the next 1-3 years.

Q15. ***Do you agree that distributors' visibility of the location, size, and functionality of DER needs to be improved within the next 3–7 years to support network planning? If not, why not?***

Answer: No, we see distributor visibility as a priority within the next **3 years** in order to start planning for network management. A timeframe of 3-7 years is too late.

We note that the Authority states in 4.104 that Consumption Data can be analysed to identify locations of EVs. This is not the case. Some success has been had in using consumption data to identify locations of larger 7kW+ chargers, but consumption data cannot be used to identify the location of those EVs that are charged via a three-pin plug (which is how the majority of EVs are charged in NZ based on EECA surveys).

Q16. ***Do you have any views on the type and size of DER that needs more visibility?***

Answer: We consider that DER, in excess of 5kW, needs more visibility as these require us to assess applications as part ensuring network stability, safety and to understand the impact of export energy on the network.

Q17. ***The Authority acknowledges that definitions of 'real-time' vary, please explain what real-time data means to you.***

Answer: Real-time data means "up to the minute" information – near instantaneous information as opposed to information on what occurred, for example, at a customer's premise 15 or 30 minutes or longer ago.

Q18. ***Do you agree that access to 'real-time' consumption and Power Quality Data won't be needed for at least five years?***

Answer: Most likely. Non-real time data is needed now by distributors for planning purposes (e.g., to identify where investment is need or where flexibility could solve an issue). In contrast, real time data is a requirement for the operation of the network when DER and flexibility services become more prevalent. Given timeframes for significant uptake of DER and flexibility services, a 5+ year timeframe for distributors to need real time data is probably realistic. However, we think this is an issue that needs to be considered by the Authority before the need exists – so perhaps the Authority should consider what it can do to encourage real time data in 3-5 years.

Q19. ***Do you agree that flexibility traders' access to ICP data must be improved so they have the same level of access as distributors (and retailers), with whom they might be competing to provide contestable services? If not, why not?***

Answer: Yes, to a degree, as long as it serves the purposes for which it is intended i.e., consumption or periods in the day when flexibility services are required. We suggest that the Authority should take guidance from industry forums on this.

Q20. ***Do you think the Authority should prioritise modifying the Data Template, so that flexibility traders can use it, or should the Authority prioritise amending the Code to clarify that MEPs must provide ICP data directly to flexibility traders and distributors for a set of permitted purposes without the need for retailer permission? If neither, please explain why.?***

Answer: Yes, we agree that the Authority should amend the Code to ensure MEPs provide the necessary consumption and other data to distributors and flexibility traders. Currently retailers have agreements with MEPs to mitigate other stakeholders being able to access consumption data which will need to be addressed. It would be prudent to set out the permitted purposes for which consumption data may be used without the retailer's permission.

Q21. ***Do you agree that flexibility traders need access to granular current and likely future Congestion Data on distribution networks within the next 1–3 years?***

Answer: Clause 2.3.13 "*Map of anticipated network expenditure and network constraints"* of the Commerce Commission's Information Disclosure requirements, outlines the congestion reporting requirements for EDBs. This should provide sufficient information to flexibility traders in EDB's Asset Management Plans.

It is highly unlikely that it will be feasible to provide LV level congestion mapping in the next few years as much as we support an open access data principle. We foresee it being similar to how the UK has evolved in this space where the focus has generally been on HV flexibility initially. Consequently, as stated earlier in our submission, we do not believe a 1–3-year timeframe is realistic, and hence question the value of the Authority prioritizing this area for examination.

Q22. ***Are there any other issues preventing distributors from providing granular current and likely future congestion data?***

Answer: Yes, refer to response to Q21. System visibility, appropriate capability and sophisticated modelling will be required to identify current and future congestion at a LV level. These are high-cost developments and unlikely to be feasible across all EDBs at LV level in the next 1-3 years. Without visibility of the grid edge which can be gained from smart meter data Orion has had to take a top-down approach to congestion forecasting. Last year we published a congestion map for FY23 using just one scenario across all 50 Zone Substations. This year, at the same time as releasing our AMP, we are publishing an updated map covering FY24, FY25, FY26, FY27 and FY28 once again using just one scenario for all 50 Zone Substations. We are also currently developing the models required to forecast down to the ~12,000 distribution substations. The issue with this modeling is that we currently have % 5 coverage of distribution substations with our LV monitors and the rest of the data set is reliant on scaled information gained maximum demand indicators. With respect to forecasting down to the level of our ~220,000 ICPs, its value would be questionable without smart meter data to scale the simulations. We are currently in negotiation with a Metering Equipment Provider to gain access to smart meter data for 93% of our ICPs.

Two other issues preventing distributors at a collective level from providing granular current and likely future congestion data is that there is no consistency in how the scenarios are built up or how After Diversity Maximum Demand is calculated.

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?***

Answer: We agree that the visibility of larger DER needs to be improved. However, it would also be valuable for distribution system management to have visibility of customers smaller DER e.g., vehicle batteries to reduce local constraints. For both large DER and small DER visibility the time frame of 3-7 years is too long. It needs to be sooner i.e., within next 3 years.

Q24. ***Do you have any views on the type and size of DER that flexibility needs to have improved visibility?***

Answer: EDB's generally want to manage the peaks on their networks. Any DER connection that has the ability to optimise a network connection has value in managing peak demand. We therefore do not have a specific view on certain types and sizes but rather the ability to have visibility of all DER to enable better network management.

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?***

Answer: Yes, the existing registry seems the most appropriate place to record DER details.

Q26. ***Do you agree that the Authority should prioritise work on addressing the other issues outlined in this paper?***

Answer: Yes, although the Authority should consider the value of each issue to stakeholders and whether other issues have minimal impact on the desired outcomes i.e., access to data e.g., an API would take priority for central storage rather than data templates.

Q27. ***Do you agree that flexibility trader access to real-time congestion and ICP data won't be needed for at least five years?***

Answer: Yes, it is likely a mid-term issue and needed in the 5+ years window.

Q28. ***Do you agree that model privacy disclosure terms are appropriate?***

Answer: Yes, model terms would be required to align with the Privacy Act. There is something to be said for standard disclosure terms that communicate in plain English how retailers collect, use, store and disclose personal information. If the current privacy notices/statements are inaccurate or confusing, then everybody will benefit from using well drafted model privacy disclosure terms.

Q29. ***Do you agree that model privacy disclosure terms would facilitate data access?***

Answer: Yes, however model disclosure terms are only going to facilitate data access if they are clearly worded and specifically authorise the disclosure of data that is required to industry participants. These terms need to specifically support regulatory certainty and that the data will be treated appropriately, aligned with the Privacy Act.

Q30. ***Do you see any practical issues with this proposal?***

Answer: Further consultation with industry participants as to the nature of the model terms would be required.

If the model privacy disclosure terms are optional, then it will be up to the retailer whether they want to adopt them. A quick review of privacy statements for retailers shows they are many and varied. Adopting model privacy disclosure terms will no doubt raise translation issues for each retailer with their customers and require rewriting of privacy statements in a different tone of voice. Updating of privacy statements needs to be communicated to all customers so there are costs involved in this process.

Paragraph 4.128 of the Issues Paper refers to the model terms including links to the distributors and third party's privacy notices. Given the number of distributors, each retailer may deal with various third parties which could be a substantial number of parties. We question whether this:

- Is this practical?
- Is this going to be clear for customers or is it better not to link it directly or to refer to it only?

Q31. ***Should the Authority create model terms for distributors and MEPs as well given the range of data being collected through smart meters? If not, why not?***

Answer: As mentioned above, there is something to be said for standard privacy disclosure terms that communicate in plain English how distributors and MEPs collect, use, store and disclose personal information. However, given that we are still waiting for the Ministry of Justice to complete their policy work on changes to notification rules under the Privacy Act 2020, our submission is that we wait to see the outcome of that work before embarking on any possible model terms for distributors and MEPs.

Q32. ***Would the industry find it helpful for the Authority to conduct workshops on privacy preserving/minimisation techniques?***

Answer: Yes, it would assist both the EA and market participants get a better understanding of privacy preservation techniques.

Note: there was an error in the consultation paper with 2 question numbers being duplicated, the next 2 questions are the responses to the duplicate questions 31 and 32.

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?***

The options listed appear appropriate. We though are uncertain of how large an issue of favouring network solutions is however as certainly from Orion's perspective we are driven by delivering the best lowest cost solution for our customers – regardless of whether this is a network solution or NNS/flexibility solution.

If there is hesitancy by some distributors to considering flexibility solutions, then one possible reason may be a lack of knowledge on how the costs of flexibility compared to network solutions. It is likely that in the absence of regulation around disclosure of pricing, contracts between distributors and flexibility providers may make pricing a commercially sensitive item that is unable to be shared beyond the two parties to the contract.

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?

There may be instances where it would be appropriate for networks to own DER or battery storage as a least cost investment option for electricity supply to consumers in comparison to provisioning a third-party provider. Generally, we would see that in the majority of instances third party providers would likely be the least cost option, but this may not always be the case. For example in remote locations where distributors have staff available to install/maintain large batteries but third parties don't, or where the timeframe for the need for a battery simply precludes the ability for distributors to go to market.

We believe this is an area where there is potential to jump to a regulatory solution that lies at one end of the spectrum (i.e. no distributor ownership of DER) where perhaps a more nuanced and stage-by-stage approach to regulation may be better.

For instance, an alternative solution in the medium term would be to allow distributor ownership of DER but regulate that where distributor ownership occurs the distributor must publicly state the reasons why third-party ownership wasn't preferable/feasible. Also, as a second caveat to any distributor ownership, distributors could be required to tender to outsource the DER/batteries to flexibility traders during trading periods where the distributor is not requiring the battery to discharge. This would then enable the DER/battery to still be used for the whole 'flexibility stack' rather than for simply network purposes, and hence result in lower costs to customers. Depending on how this approach works in the medium term, then the Authority could consider whether or not in the long term DER ownership should be limited to third party providers.

5. Market settings for equal access

Q33. ***Do you think there are circumstances in which the Authority should extend the arm's length rules? If not, why not?***

Answer: No, this is covered by the Commerce Commission's Related Party Transactions to ensure Arm's length transactions take place in regulated businesses. This test ensures that services are competitively priced, efficient, and market tested.

Q34. ***Do you agree with the Authority that Option 1 should be implemented, and that Option 2 could be considered in the event of allegations of, or instances of anti-competitive harm in contestable markets (Issue 3)? If not, what alternative option/s would you favour,if any?***

Answer: No, see response to question 33. The Government Initiated Decarbonisation Incentives (i.e., the GIDI fund) allows businesses alternative options to incentivise the transition, and we are already engaging with industry participants and trialing flexibility services with third-party providers as opposed to being "anti-competitive".

The Commerce Act, Part 2, Section 36 also provides the Commission jurisdiction to monitor restrictive trade practices and taking advantage of market power.

6. Capability and Capacity

Q35. ***What do you think of the Authority's option of using the education option proposed elsewhere in this paper, to include some guidance on how distributors should collaborate in future?***

Answer: The distribution sector already collaborates between EDBs extensively as well as with other industry participants . Orion has shown leadership in this space e.g., Flexforum, Upper South

Island Load Management, Deta process heat work, etc. However, we would be interested in understanding where the Authority has identified gaps in collaboration.

Q36. ***Do you think it would be helpful for the Authority to encourage the use of joint ventures between distributors to increase their integration of DERs (Distributed Energy Resources) and their procurement of NNS projects? And should this be combined with the first option?***

Answer: No, business arrangements and models such as joint ventures are unique and specific when the terms are negotiated in respect of DER requirements between parties. It would not be helpful to try and articulate this in standard type terms and conditions or procurement. Business arrangements and models should be left to the entities entering into the joint venture to negotiate the most suitable arrangement.

7. Operating arrangements for flexibility services

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?***

Answer: Yes, monitoring progress would be a good idea. At this stage, procurement for NNS is still in an emerging phase as experienced by some EDBs and it is expected to take some time to form standard approaches to negotiating agreements.

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?***

Answer: The Authority could request periodic (preferably annual) confidential reporting from industry participants on flexibility service contracts which have been negotiated, including details of the service and timeframes to negotiate contracts in order to monitor uptake of these services.

We also encourage face-to-face informal catchups with the Authority to discuss opportunities such as the one which Orion is trailing in Lincoln with an aggregator.

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?***

Answer: We recommend that the Authority initiate consultations with industry participants at a later stage once there has been sufficient negotiation and experience gained in setting up operating agreements. In the meantime, the Authority could run periodic workshops where practical learnings from operating under these agreements could be shared by relevant participants (excluding any confidential matters) to build trust in new ways of doing business e.g., benefits and challenges, what I would do different next time etc.

8. DER Standards

Q40. ***What are your thoughts on the proposed scope for the Part 6 review?***

Answer: We agree that Part 6 of the Code is due for a significant review and update and that DER be included, as opposed to only Distributed Generation (DG) .

The purpose of Part 6 is a connection framework and the regulated terms of DG. If DG is replaced by DER, then DER would need to be defined in the Code.

DG is limited to generating plant or equipment used for generating electricity.

We recommend that the following is included when the Authority reviews Part 6:

- Distributed Energy Resources (DER) are defined as technologies to generate, store, or manage energy behind and in front of the meter. They can be:
  - Uncontrollable – wind and solar
  - Controllable – output can be turned on or off to increase or decrease demand

Controllable DER allows for flexibility and the ability to modify generation and consumption patterns in reaction to an external signal or incentive through a flexibility service.

Flexibility Services are services that take the flexibility available from controllable DER and send it on behalf of DER owners to buyers of flexibility at an agreed price. Thereby fulfilling the demands for flexibility that are representative of their value stack.

What, if anything, would you include or exclude, and why?

In addition to the issues raised in 8.14, we also consider the pricing and the incremental cost rule, incorporating DER into schedule 6.4 and a revision of Schedule 6.5 maximum fees. We also note that the Authority provided an ACOT Code amendment[8] around distributed generation dated 14 December 2022 regarding incremental costs as a result of connecting DG. We recommend that the authority considers the impact of this change to updating the regulatory settings. This might mean that the Authority needs to clarify that incremental costs can be used as opposed to the schedule of fees.

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[8] https://www.ea.govt.nz/assets/dms-assets/31/ACOT-Code-amendment-instrument.pdf

We also recommend that the Authority consider the impacts of reporting annual DG statistics to MBIE under Electricity (Statistics) Regulations 1996[9] and propose that these also get reviewed.

Q41. ***In order, what are the three most important issues that should be addressed as part of a Part 6 review, and why?***

Answer: Alignment with AS/NZS4777 requirements for residential 5kW per phase export limitations for installations. Having this limitation would align with the installation standards. If a connection could not handle a 5kW export, then it unlikely to be able to have the capacity for EV charging in the future.

There needs to be more stringent obligations on installers of DER. We have seen that they may prefer certain technologies where there are better margins as opposed to the best solutions for their customers.

Many EDBs allow their engineers to approve DER connections based on unknown engineering solutions. This could take from 48 hours to 2 weeks depending on the assessment criteria e.g., time consuming voltage calculations. We would suggest a framework or guidelines for assessments.

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?***

Answer: It is important that Part 6 is updated to include DER so that it remains relevant, and not only focused on DG. The Code does not address DER upgrades or make it compulsory to record DER modifications (i.e., installations and removal of installations).

The registry does not have a field for battery inverters and storage capabilities e.g., kWh of storage. As a consequence, Orion currently populates the register with battery inverter as "Other" and cannot record storage details. There's also no facility for V2G inverter sizes and storage capacity.

The Authority could also look at issues identified with the connections process, identified in the UK, in respect of low compliance due to manual processes which have since been automated through Smart Connect. This was developed through innovation funding. This enabled power networks to handle increased volumes of DER applications without having to

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[9] https://www.legislation.govt.nz/regulation/public/1996/0017/latest/DLM208427.html?src=qs

increase resources to handle the applications.

Q43. ***What are your thoughts on increasing the size threshold for Part 1 DG applications, including the benefits and drawbacks?***

Answer: Orion submits to remove Part 1A, because of complexities but consider shortening application time limits in Part 1. If the Authority adopts the 5kW export limitation, then there are no complex engineering solutions required.

Q44. ***If the threshold were to change, what do you think the new threshold should be and why?***

Answer: Point 8.8 is currently DG less than 10kW and should be 15kW (5kW export per phase) under Part 1. This once again aligns with the standards. Part 2 currently has DG greater than 10kW, we recommend that it should be 15kW to 1MW. The reason is that over 1MW requires Transpower to be notified, with Utility / Grid scale solar being 1MW and above.

Q45. ***What are your thoughts on adjusting the ten-business day time limit in Part 1A?***

Answer: 10 business days is appropriate for approving applications of less 10kW (or 15kW as we suggest in Q44). We recommend removing Part 1A due to its complexities. This is better managed by including some aspects of Part 1A in Part 1. e.g., if a consumer is installing DG of less than 5kW or able to restrict export to less than 5kW then would there be any reason that we would not approve the installation which aligns with Part 1A.

Q46. ***What are your thoughts on maintaining the current approval time frames in Part 1 (comprehensive) and Part 2?***

Answer: Part 1 and 2 are appropriate but more flexibility is required for larger connections great than 1MW.

Q47. ***If you seek a change to approval timeframes, what evidence can you give to support this?***

Answer: We do not see the need for a change in approval timeframes other than mentioned in question 46.

Q48. ***What are your thoughts on adding a new DG application process for large-scale DG to Part 6? Please provide examples in support of why you think change is or is not necessary.***

Answer: Orion supports adding a new application for larger scale DG greater than 1MW. These can take significantly longer to negotiate given the investment size, technical needs (e.g., feasibility studies and wide area network protection studies), regulations such as resource management, and land acquisition.

Q49. ***If you think a new application process should be added, where should the threshold be and why?***

Answer: Applications of greater than 1MW need extra time to address the complexities of the application

Q50. ***What are your thoughts on reviewing the priority of applications clause in Part 6 of the Code?***

Answer: No Comment

Q51. ***Should the AS/NZS 4777.2:2020 Standard be mandated for inverters in New Zealand? If so, how should this be accomplished?***

Answer: Yes, AS/NZS 4777.2:2020 should be mandated as these technical standards are updated when needed and there is no reason for this to be any different for purposes of the regulatory settings.

Q52. ***What are your thoughts on the Authority reviewing the prescribed maximum fees in Part 6 of the Code?***

Answer: Yes, these should be kept under regular review as changes occur such as inflation etc. These fees will apply to grid-scale solar applications as well. Application fees for utility scale generation do not reflect the true cost of time spent on applications. e.g., $5,000 does not reflect the true cost of the assessment.

An example of an installation could be Kowhai Park[10] 150 MW where the project could be in excess of $10M where the EDBs investment is approximately 5-10%. This could be done at a rate per hour, a rate per MW or seeking further feedback if a capped price is required. Transpower, has a set fee up to 1MW and for every MW after that there is a set fee of $1k.

There also needs to be flexibility on assessment of capacity and would also depend on location of the installation. The max $5k initial application fee large DGs can be very limiting given the complexity of the application in respect of evaluating network capacity, location and providing a design concept or new additional network to facilitate the connection e.g., building additional 11kV or 66kV lines to a site.

We recommend that the Schedule of Fees incorporates incremental costs aligned with the Part 6 amendment mentioned in the response to Question 40.

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10 https://www.christchurchairport.co.nz/globalassets/about-us/sustainability/kowhai-park/kowhai-park-sustainably-powering-the-next-generation-2023.pdf