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Submissions
Electricity Authority
P O Box 10-041
Wellington 6140

By email: distribution.feedback@ea.govt.nz

Tēnā koutou

Issues Paper-Updating the Regulatory Settings for Distribution Networks

WEL Networks (WEL) appreciates the opportunity to provide feedback on the Electricity Authority (Authority) Issues Paper- Updating the Regulatory Settings for Distribution Networks.

As noted by the Authority, this Issues Paper builds on the July 2021 Discussion Paper and the subsequent information request to distributors. The information WEL has provided in both of these processes remains highly relevant and supplements this feedback on the current Issues Paper.

As well as providing feedback on the individual questions and issues discussed, we have made some suggestions about the topics or work we believe the Authority should prioritise.

In our view this Issues Paper addresses two topics:

1. Capability and capacity within distribution networks: we contend that it is very difficult for the Authority to regulate in relation to this. Current and expected future shortfalls in capability and capacity are a well-recognised issue across the sector. Distributors are commercially incentivised to participate in different initiatives and industry forums to manage and/or reduce any potential impact on electricity consumers on our network. We note the Electricity Networks Association (ENA) is already facilitating the sharing of information about non-network solution projects with other distributors and stakeholders across the electricity sector.

2. Distributed Energy Resources (DER) and the relationship the host distribution company: by definition the generation and load resources that make up DER rely on connection to the distribution network. The DER standards section of the Issues Paper addresses connection issues while the other topics analyse what and how these DER resources turn up (equal access to data and market settings) and how they are managed (operating agreements) to maximise value for all consumers.

Our approach to DER is wider than generation and/or load owned and connected (and potentially controlled) behind the meter by end consumers and incorporates current commercial entities owning and operating DER. We expect the breadth of ownership of these DER will continue to grow.[1]

[1] We note and support the Authority's use of FlexForum's definition of Distributed energy resources from "A Flexibility Plan 1.0: what we need to do and how we can do it". 31 August 2022 in footnote 1 of the Issues Paper.

We note this Issues Paper focuses purely on any value from DER that is attributable or realised via the relationship or interactions with the connected distributor. While the Market Development Advisory Group's Options Paper on 'Price discovery in a renewables-based electricity system' (seeking submissions at the same time) is only focused on the relationship of DER in the wholesale market. We submit that this siloed approach must be bought together to ensure the overall regulatory regime enables DER owners, and therefore the whole electricity system, to maximise the value of these investments. For example, as we submitted on the Winter 2023 consultation paper, "*WEL has the ability to manage load to ensure efficient distribution network operation. We can choose to offer load management to assist with national demand and supply risks but seek absolute clarity on a hierarchy of how and who has the rights to this load management and how it's paid for*".

We have installed smart meters on over 70% of the ICPs in our network. We use the data from these meters for planning and operational purposes. The data informs load forecasts on distribution transformers, identifies low and high voltage problems, and detects interruptions on LV networks (e.g. when multiple smart meters on the same LV feeder simultaneously issue a last gasp alarm). The smart meter data is also used to detect broken or high impedance neutral connections.

Our position remains that distributors should not be prevented from undertaking near real-time distribution system operator (DSO) functions which could rely on DER, where this provides the greatest long-term benefit to consumers. Many of the constraints (especially relating to voltage) will be localised, therefore effective management will require a component of real-time decision making and network edge control. It will be critical in developing regulations in this space that there is a guiding principle to maximise the long-term benefit to consumers and to ensure that any regulations are flexible enough to adapt as technology and requirements continue to develop.

The Issues Paper identifies a number of quite specific issues. It's unclear at this stage what the relative costs and benefits of pursuing individual options would be. From our perspective, we suggest the Authority prioritise addressing the following 3 issues in the near term (implemented within 12 months):

1. mandating inverter standards and determine other currently available 'smart' products that could be regulated to assist with their contribution to the potential of distributed energy resources, for example smart EV chargers
2. update the maximum prescribed fees for distributed generation applications
3. queuing and congestion management for new distributed generation connection applications

These priorities reflect the knowledge that a review of the DG Pricing Principles is underway by a different team at the Authority, with consultation due in the near term.

In addition to this submission, WEL also supports the views expressed in the ENA submission.

Ngā mihi nui

David Wiles
Revenue and Regulatory Manager

Appendix 1 – WEL Network's response to specific questions

Chapter 4 Equal access to data and information

In general, WEL agrees with the Authority's aim:

> *"The Authority wants to manage risk, remove barriers to market development, and create an enabling environment, rather than predetermine who should or should not do what. The Authority wants to stimulate the uptake and best use of DER. We should like to preserve optionality and adopt measures that are likely to have positive outcomes, regardless of how the markets for flexibility services develop (so-called 'least-regrets' measures)."* (para 2.25)

A 'least-regrets' approach can be ensuring any Code changes do not foreclose future opportunities, but it can also underpin regulatory inertia – a fear of doing anything because the future is unknown. For example, in the staged approach to facilitating equal access to data for competing participants the Authority is suggesting it could take up to 5 years for data to be available to provide visibility of DER on the LV network.[2] The Authority also suggests "*Data requirements in the short term (the next five years) will likely be for samples of, say, month-old, ICP-level, daily consumption and perhaps power quality data*".[3]

WEL is already collecting 5-minute meter data across 70% of its network. The investment to do this is already paying for itself via improved management of network congestion, outages and maintenance.

The case for digitising NZ's electricity system para 4.46 -4.52

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?

WEL suggests, where possible, NZ should leverage learnings from work already done. However, any effort should be based on the practicalities and applicability given the different jurisdictions and reduced applicability due to technology advances since the Taskforce carried out its work.

WEL queries whether the full value of these reviews to the Authority's knowledge base would be realised by contracting a third party to undertake this work. A better option would be to establish a working group with industry participants to identify from first principles recommendations that work in the New Zealand context.

What information do distributors need and why? Para 4.54-4.61

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 used for?

[2] Paragraph 2.41 of the Issues Paper

[3] Paragraph 4.2 of the Issues Paper

WEL submits that operational real time data (e.g. last gasp, first gasp, voltage) should be distinct from power quality data. This operational real-time data can be used to reduce interruption durations and identify voltage problems, providing a better service to the end consumer.

However, power quality data-V, pf etc are quite useful for long term planning purposes. WEL also values having information that enables detection of broken or high impedance neutral connections and HV fault detection.

WEL submitted in September 2021:

"To support the management of a network with significant levels of DER, information such as: DER settings, near real time voltage and loading data, DER (EV) locations, ICP phasing, LV circuit information, DER output projections, maximum and minimum load profile, DER communications standards, communications protocol, market set up, incentive and tariff options will be critical. All of this information will be necessary to support the development of network technology, operational, and commercial models.

WEL believes that, in addition to the information requirements outlined above, optimal investment and operation decisions could be made if we had timely access to the same data which our own smart metering equipment provides. WEL has access to smart meter data for over 70% of our connections because of prior investments made in this area to enable LV visibility. Datasets include UIQ (energy volume interval), ODS (outage detection), control channels and SIQ (power quality). Currently we are continuing our work on data analytic and data science to support the advanced features like phase identification, dynamic ADMD calculation, GIS data validation, broken neutral detection using a combined voltage and impedance based method, etc."

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?

The issue goes beyond DER integration. Distributors can use real-time operational data to improve reliability and power quality so recommend availability of operational data be a high priority (and higher priority than power quality data).

What information do flexibility traders need and why? Para 4.62-4.68

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

Understanding the network capacity issues and network planning is a function currently done by distributors. While flexibility traders in future may be able to provide new solutions, the problem statements will be best explained by distributors. This is further supported by the fact that distributors have the overarching view of upstream and downstream network data and are therefore best positioned to provide this insight to the market.

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

WEL notes that the information being discussed is firstly important to distributors to be able to determine their need for flexibility services and then engage in purchasing the service.

Part 1: Issues hindering access and availability of key data for distributors

The Issues Paper identifies numerous issues hindering access to and availability of key data for distributors and flexibility traders (discussed over 28 pages of the Issues Paper). The quantum of issues (and range of potential solutions) indicates to us that the current Registry and access to data is not fit for purpose.

WEL's view is that it is time for the sector to bite the bullet and implement a modern / state of the art central registry. A new system should collect meter data. This 'platform' should be open access to consumers, retailers, distributors and flexibility suppliers (etc) subject to conditions of use which ensure the appropriate privacy. All except consumers could be charged a universal fee for having access.

Answers below to Q6 to Q14 assume the current Code and arrangements remain in force, with the associated inefficiency. We reiterate feedback provided in September 2021 which remains relevant.

Issue 1: Improvements to the default Data Template are required to enhance its workability Para 4.78-4.85

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?

WEL submitted in September 2021:

"To date, WEL has refrained from implementing the DDA Data Template in its current form as we believe it is not fit for purpose. WEL is in a fortunate position with 70% LV visibility, however we strongly supported the adoption of the cross-industry proposed Code amendment which aimed to solve many of the issues with the Data Template, in order to allow other distributors to access similar benefits and increase our own visibility closer to 100%. Discussions with other distributors (who have implemented the Data Template) have indicated that negotiations with retailers have progressed slowly and data access costs are likely to be prohibitively high."

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?

It is clear from the feedback above that changing the maximum frequency of receiving data from six monthly to monthly does not achieve the desired outcome for EBDs (or maybe also flexibility traders). (para 4.84(a))

Issue 2: Retailer permissions are often necessary for distributors to receive ICP-level data for their distribution network para 4.86-4.90

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

WEL submitted in September 2021:

"The industry generally accepts that there is value in the distributors having access to consumption data to improve the operation of their networks through LV network visibility, outage restoration etc. Where concerns lie are with:

- Current holders of data being required to become a data supply operator (which they are not geared up to be and sometimes for data they have not procured) through regulatory means;
- The data supplied through regulated means being used for competitive services in which they themselves are involved in;
- Lack of transparency with the consumers of who has access to data and for what purpose; and
- Costs of data procurement not being met by all those who derive value from its use.

The Default Data Template only addresses the usage concern and creates additional cost in the administration and working of the agreements.

A major factor in generating these concerns is the current de facto data flow of: meter → MEP → retailer → all other parties. A straightforward fix for this would be to remove the retailer from being the main distribution point by expanding the obligations in Part 10 of the Code to enable MEPs to supply data direct to distributors in the manner distributors require.

In this way, the retailer is removed from the chain of data supply, efficiencies such as business-to-business services, APIs and standardised data formats can be gained, participants can receive data that suits their particular needs and timing, and those developing and offering competitive services do so on an even playing field.

Considering the MEP market is dominated by two suppliers, it will be important to ensure that metering data pricing models are adjusted to ensure that sunk costs are not over-recovered with multiple data provisions, but this paves the way for further multi party services under the ACCES developments. Privacy Act principles will protect consumers to ensure data is only used for the purpose it is gathered for and distributors can demonstrate adherence to 3(b) via the participant audit process. Consumers and their agents still have the ability to receive their consumption data but efficiencies in provision of data may be created if retailers create arrangements with the MEP to supply."

Enabling distributors to work directly with MEPs will also enable distributors to get power quality data.

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

Yes.

Issue 3: Distributors are not permitted to receive Power Quality Data in the same way as Consumption Data para 4.91-4.94

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

See answer to Q8 as a starting point. However, a self-service online solution would be better, such as a central registry.

Issue 4: In addition to gaining retailer permission to collect ICP data direct from the MEP (e.g., completing a Data Template), a distributor must also negotiate an access agreement with the MEP para 4.95-4.96

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 develop a default template to help reduce transaction costs?

Data should be made available to distributors at the incremental cost to produce the data in an agreed template. A charge of $2-3 per ICP/year is not economical and will result in non-optimal expenditure.

Issue 5: MEP pricing for provision of ICP data and other services to distributors (and other parties) is not transparent para 4.97-4.102

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?

See answer to Q11.

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?

See answer to Q11.

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?

WEL agrees that transparent 'pay-as-you-go' pricing would improve access to smart meter data for distributors.

Issue 6: Distributors need better visibility of non-exporting DER para 103-4.107

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?

Yes, having a view of EVs and charger details will be critical to understand the impact and plan for management of the LV network in particular. Similar to how PV installations are available against ICP details in the Registry, a central database for EV chargers and residential battery systems is crucial. Information on how DER is being operated (e.g., as part of a demand response scheme, peak shaving, in response to pricing tariffs) is also useful – this should be revealed by 5-minute meter reads.

While data on EV sales is available in a regional basis from NZTA, it's not granular enough to determine impacts on the network at the residential suburb level. There is a question about whether the EV charger data should be linked to both the physical address (i.e. the ICP linked to the meter) and the customer who will take their EV with them (and the charger) when they shift house.

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

WEL submits dedicated residential EV chargers and residential battery system data needs more visibility.

Issue 7: Distributors do not have access to real-time consumption and Power Quality Data para 4.108-4.109

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

Real time data, including operational data, no later than 5 minutes after measurement could enable better customer service benefits for customers.

WEL has direct experience of these benefits as "WEL has access to smart meter data for over 70% of our connections because of prior investments made in this area to enable LV visibility. Datasets include UIQ (energy volume interval), ODS (outage detection), control channels and SIQ (power quality). Currently we are continuing our work on data analytic and data science to support the advanced features like phase identification, dynamic ADMD calculation, GIS data validation, broken neutral detection using a combined voltage and impedance-based method, etc." (submitted September 2021)

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

WEL already incorporates real-time data in its operational processes. Building business processes and systems to process data and yield benefits to customers will take time. Hence the sooner this data is available the better. We disagree that a 'no-regrets position' is that this data won't be needed for at least 5 years.

Part 2: The issues hindering access and availability of key data for flexibility traders

Issue 8: Flexibility traders do not have access to ICP data para 4.110-4.112

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?

Distributors and retailers use ICP data for certain purposes that may differ from what flexibility traders would use the data for. The same level of access is not automatically required, and it is likely that flexibility traders might require additional information e.g., congestion information to effectively compete.

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.

WEL suggests gaining access to the data directly from MEPs has greater value (and bypasses the need to modify the Data Template).

Issue 9: Flexibility traders do not have access to granular network congestion data on LV network para 4.113 – 4.116

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?

Flexibility traders need either congestion data or congestion related price signals or tariffs to develop products suitable for network support.

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

Methodologies for assessing congestion on LV networks will need to be refined. Development of business processes and applications will also be required. Accurate forecasts of future congestion data will depend on having good assumptions around future DER connection.

WEL submitted in September 2021:

"To date there have been no significant issues with the connection of DER on our network. However, the trials which we are running on the network have begun to show where problems may arise from the connection and operation of different types, and sizes, of DER. We continue to build our understanding in this area to mitigate any future issues which may prevent or hinder DER owners from connecting to our network and operating effectively.

The actual permissible operating envelope (especially the upper band of the voltage profile) has important implications for congestion. The operating envelope needs to be reviewed by assessing the real impact of voltage increase. If the band can be extended without causing issues to customer connections, this will greatly improve the hosting capacity and enable non-network solutions to be employed."

Issue 10: Flexibility traders do not have visibility of the location, size, and functionality of DER on LV networks para 4.117-4.122

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.

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

Improved visibility of DER with controllable offtake and controllable injection will improve system outcomes. The size of DER depends on network congestion which depends on other DER on the network. If a network has sufficient capacity for a 100 kW DER, then no visibility is required. If a network is congested, then much smaller DER needs to be visible.

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?

No.

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

No.

Issue 11: Flexibility traders do not have access to real-time granular congestion or ICP data para 4.123

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

Real-time congestion data will need to be provided by the distributor and will take several years to be implemented in real-time. It may be more efficient for local LV network congestion data to be provided directly to the ICP / customer and incorporated there into a flexibility trader's app.

Part 3: Enhancing disclosure to consumers to enable data access

Issue 12: Privacy Law transparency requirements could be perceived as a barrier to disclosing ICP Data para 4.124-4.130

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

Yes – this would be useful to standardise and simplify privacy issues. However, in WEL's view there are higher priorities for the Authority's limited resources.

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

There are a number of steps that require attention before model privacy disclosure could facilitate data access.

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

No comment

Q31 (pg. 46) 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?

Yes.

Q32 (pg. 46) Would the industry find it helpful for the Authority to conduct workshops on privacy preserving/minimisation techniques?

This could be done by other organisations as well – the industry or ENA could lead this discussion.

Chapter 5 Market settings for equal access

Issue 1: Distributors may prefer network solutions when non-network solutions could be more efficient para 5.22-5.49

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?

Given the rapid growth in DER that is currently occurring, we are developing strategies and policies for the competitive procurement of flexibility services in the near future.

WEL believes that distributors will need to develop and publish clear technical and operational requirements for DER, so that a deep and competitive market for flexibility services can develop. However, we also believe that it is critical that distributors are not unnecessarily hindered from utilising the knowledge and experience they have of their own networks when acquiring non-network services to deal with issues identified in the network in near real-time.

Option 1 is not preferred (education and guidance for distributors on flexibility services).

Option 2 is not preferred (fund trials and assistance with tender and contractual arrangements). Many distributors are already undertaking trials with new technologies. Information about trials can be disseminated at industry events such as the EEA annual conference. The ENA is also publishing relevant information on its website.

Option 3 (distributors required to show they have explored NNS) is workable. However, if the NNS is required at the LV network level then the investment threshold may have to be very low which may result in a large amount of work for distributors. WEL's understanding is that the Commerce Commission's Information Disclosure regulation already requires distributors to publish in their Asset Management Plans what NNS they have investigated and why a decision was made to invest in traditional poles and wires.

Issue 2: Distributors may favour in-house NNS para 5.50-5.88

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?

WEL agrees with the ENA that the Authority has misrepresented the MTR and Kāinga Ora trials – these trials are not examples of investigating non-network solutions.

Option 3 is preferred (encourage distributors to make 'standing offers' for DER).

Distributors controlled / uncontrolled tariffs and EV tariffs could be described as a 'static' form of standing offer. Making the 'offer' more dynamic, especially at the LV network level, requires more detailed analysis of the benefits versus the costs.

Option 4 does not seem to provide much value (Authority monitoring distributor's use of competitive procurement). The ENA is already publishing in one place information about competitive procurement of NNS by members.

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

It would be a substantial policy decision to extend the arm's length rules. At this stage WEL suggests there is no evidence to justify this option. If there is evidence of situations where extending the arm's length rules will provide material benefits, then the option remains open to the Authority.

Issue 3: Distributors could use their monopoly position in distribution to secure an advantage in contestable markets para 5.89-5.118

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?

Yes (option 1 = Authority monitors the behaviour of distributors in contestable markets).

The need for Option 2 has not been proven (impose arm's length rules on distributors in certain downstream contestable markets). Distributors already operate with tight related third-party rules under the Commerce Commission's regime. Both the Commission and the Authority would be interested if there were allegations of anti-competitive harm.

Chapter 6 Capability and Capacity pg. 66-71

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?

The Authority does not regulate capability and capacity so it would be more appropriate to address these issues outside this Issues Paper.

Collaboration is happening and the Authority's scarce resources should be applied to higher priority projects than providing guidance on how to collaborate. We provided the following recent examples of collaboration which WEL had been involved in in our September 2021 submission:

- Founding member of SmartCo, a multi-distributor joint venture to procure and install smart metering equipment in order to enable better network investment and operating decisions
- Engaging in the Wellington Electricity EV connect forum to enable distributors to develop coordinated long term EV strategies
- Collaborating with another distributor on an agreement for a domestic EV trial so that lessons could be learned and shared between distributors
- Sharing of data visualisation platform with another distributor for smart meter data management

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 and their procurement of NNS projects? And should this be combined with the first option?

WEL suggests it is very difficult for the Authority to regulate in relation to this. Current and expected future shortfalls in capability and capacity are a well-recognised issue across the sector. Distributors are commercially incentivised to participate in different initiatives and industry forums to manage and/or reduce any impact on electricity consumers on our network. WEL submitted in September 2021 that in relation to co-ordination (or joint ventures):

"Yes, greater coordination between distributors is likely to always result in a more efficient industry. With that said, due to a finite pool of resources within each distributor, coordination has long been a key efficiency driver for the industry to achieve the best outcomes for consumers. While this coordination may not always be overt outside of the sector, WEL's long-term involvement with the ENA and EEA, and their respective members, has resulted in many learnings that otherwise may have been replicated by each distributor individually."

An option that could be implemented by the Commerce Commission would be to allow higher spending on training, development and apprenticeships for Price-Quality regulated distributors.

Chapter 7 Operating agreements for flexibility services pg. 72-77

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?

WEL agrees monitoring progress between distributors and Transpower in developing standard offer forms for procuring NNS is useful. However, some standard forms for procurement have been in place for some time – from both the Grid Owner and the System Operator. The most effective 'standard offer' has been the RCPD transmission charge incentivising distributors to reduce the volume of electricity taken from the transmission grid during peak demand periods. And this flexibility product no longer exists.

WEL suggests it's questionable whether the range of standard offers between distributors and Transpower will be effective between distributors and flexibility suppliers. Distributors, Transpower and the Authority should be open to innovation in development of non-network solutions.

WEL does not support mandating any aspects of the connection and operation standards into Part 6. WEL submitted in September 2021:

"WEL does not believe so, the Code is not an ideal framework to manage these types of connection and operation standards. While it will be important to have these standards regulated and homogenised, it is likely they will need to change or be replaced as technology continues to evolve. Historically, the Code has not been well-suited for managing issues which are evolving or in a state of flux due to the slow pace of Code changes."

"… standard operating agreements are likely to unnecessarily stifle innovation in the flexibility services market. The result of standardising distributor-retailer agreements was the DDA; a very rigid and prescriptive agreement framework which poorly adapts to change or innovation.

Until such time as strong evidence supports the need for a standard operating agreement, WEL believes a better solution is for the Authority to develop and publish a framework and guidance for flexibility service agreements." (Answer to Q16)

"Allowing distributors and flexibility service providers to negotiate mutually agreeable and beneficial operating agreements (using the Authority's published framework and guidance) would provide the optimal outcome for all parties and consequently consumers." (Answer to Q17)

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?

WEL suggests the Authority can rely on industry participants bringing to the Authority any issues they are experiencing. That is, the Authority should be reactive and not dance at shadows at this time.

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?

The Authority is an observer in the FlexForum – maintaining an open and transparent approach with this group and calling out any regulatory barriers that may be being overlooked would be valuable.

Chapter 8 DER Standards

Scope of review of Part 6:

1) amend Part 6 to explicitly include all forms of DER
2) amend Part 6 DG application processes
    2a) increase the Part 1 application process size threshold
    2b) adjust the Part 1A (streamlined) processing time
    2c) no change to Part 1 (comprehensive) or Part 2 approval timeframes
    2d) add a new application process for large-scale DG
    2e) review the priority of applications clause in Part 6
3) strengthen Power Quality Standards
4) review Part 6 prescribed maximum fees

Q40. What are your thoughts on the proposed scope for the Part 6 review? What, if anything, would you include or exclude, and why?

WEL supports a review of Part 6.

In September 2021 we wrote:

"While well-intentioned, WEL believes Part 6 of the Code is no longer fit for purpose in the maturing DG environment. The size and scale of DG applications now being received by distributors, seems to be well outside the scope considered when Part 6 was written. Consequently, regulated timeframes to assess and respond to DG applications are becoming increasingly difficult to meet. It must be appreciated that for many distributors, the network design and engineering resources which assess DG applications are often the same resources handling load customer connection requests and network planning," *Q41. In order, what are the three most important issues that should be addressed as part of a Part 6 review, and why?*

WEL's number one priority is a review of the Part 6 pricing principles however, we note this work is underway by a different team at the Authority. We suggest the pricing principles are integral to the connection of DER and would prefer if all work on Part 6 was undertaken by the same team (for example, a queuing system for connection applications has implications for the incremental cost pricing principle).

In order of priority:

i. Review Part 6 maximum prescribed fees. Owing to the added complexity of DG connections (particularly larger scale DG), the maximum allowable fees fall well short of the actual costs involved in assessing their applications. As the maximum allowable fees not do not reflect the actual cost of assessing and approving DG applications, they are currently being cross subsidised from all other connections on the network.
ii. Mandating solar inverter standards and smart EV charger standards to improve the functionality of the chargers (not just the efficiency). However, having a device pass the certification because it has the required feature is not enough. The actual device functions need to be enabled and the set points must be correct. There needs to be a process to enable this and verify this. We discuss this in more detail in the last section of this submission.
iii. Collecting information about DER so that here is visibility of the consumption or generation of that resource at the LV network level. We believe that some of the crucial features in this area are: a DER installation register, DER communications interface, protocol and capability in remote monitoring and control capability.
iv. The treatment and control of batteries so that they are set up to be a benefit to both the customer and the network (and do not negatively impact the network by increasing peak demand.

1) Amend Part 6 to explicitly include all forms of DER para 8.16-8.18

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?

WEL understands the Authority's intention is amend Part 6 Connection of Distributed Generation to include any DER that is exporting on to the distribution network. This change would mean a consistent treatment of distributed generation and distributed energy resources that export (e.g. connection and operating standards to ensure the safe operation of the network).

However, not all DER will be exporting into the distribution network. Smart appliances are likely to be used to manage demand to avoid peak congestion; smart EV charger will not be 'exporting' until the technology is enabled for V2G for electric vehicles sold in NZ.

Maybe 'exporting DER' is a first step but Part 6 is probably a hammer to crack a nut for DER like a household's smart fridge.

WEL queries why the Authority is asking the question about whether battery energy storage systems are DG (para 8.17). Batteries have already been defined in the Code as generation.

2a) Amend Part 6 application processes para 8.19 – 8.28

The Authority rate this as a high priority with implementation in 1-3 years

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

The benefits of increasing the size threshold for Part 1 DG applications would be an improvement in the efficiency of processing the DG applications. Many smaller 3 phase applications (10-30kW) can be treated as small scale DG if they are offsetting the customer's existing load.

In our view the drawbacks are:

- conflict management when all the customers want to connect to the same part of the network
- network (LV OH/Cable thermal) limitations have to considered more accurately - more accurate data is required and it more time consuming.

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

WEL notes the ENA is suggesting of a threshold of 20kW for Part 1 – that is for both the streamlined and standard process in Part 1 of Part 6.

WEL suggests 10 - 30kW or the size of the customer's existing connection, whichever is smaller. If network changes are required to accommodate the new connection then more time is required to assess the connection.

Distributers should have the freedom or a standard to decide the total DG capacity based on DG congestion, transformer size, LV thermal capacity , load profile, voltage profile, Feeder Capacity

Distributors could also consider a variable time export period for each ICP (which could be incorporated into I/E meter/inverter.

According to Figure 12 a threshold of 20kW or 30Kw would cover the majority of applications over the period mid-2019 to mid-2022. It would be interesting to understand any trend to an increasing size of each installation.

2b) Adjust the Part1A (streamlined processing time para 8.29-8.33

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

The size threshold has implications for the processing timeline. Table 6 of the Issues Paper shows the maximum time to approve a 10-19kW connection application was 375 days – that is over one year and must be an outlier that is irrelevant to this analysis. The average time for this sized DG was just about 10 days. WEL supports retaining the 10-day maximum timeframe for Part 1A. Alternatively the timeframe could vary depending on the level of DG congestion in a specific region of the network.

We note that the maximum time to approve a connection application declines as the size of the DG installation increases.

2c) No change to Part 1 (comprehensive) and Part 2 approval timeframes para 8.34-8.44

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

Current Part 2 timeframes are appropriate. There is sufficient scope for distributors to seek extensions, and this flexibility can be improved by increasing the allowed extension timeframes for larger projects (1MW).

The existing Part 1 timeframes are also appropriate. The volume of these applications is low as the majority of applicants choose to utilise the 1a process.

It would be easier to comply with these timeframes if there was an exact tool to assess the DG with real-time data.

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

Increasing congestion of DG on the network increases the complexity of assessing connections as general assumptions cannot be applied and site-specific information is required to carry out the assessment.

2d) Add a new application process for large-scale DG to Part 6 para 8.45-8.54

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.

The priority clause has more impact on processing timeframes than the overall process outlined in the Code.

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

WEL does not support a new application process being added to the Code.

2e) Review the priority of applications clause in Part 6 para 8.55-8.62

Referring to clause 6.1.17 in the Code

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

WEL supports a review of the priority clause in Part 6 of the Code. A working group with distributors and distributed generation investors could discuss and refine the problem definition as well as discuss possible solutions.

3) Strengthen Power Quality standards para 8.63-8.73

The EA rate this as a high priority with implementation in 1-3 years

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

WEL supports mandating the standard for inverters. Volt/Var and Volt/Watt capability are important for long term power quality as the density uptake of inverter based distributed generation increases. AS/NZS 4777.2:2020 provides a good benchmark for this capability. It is critical the Code / rules / NZ standard can be quickly updated if the standard AS/NZS 4777.2:2020 is superseded.

In our September 2021 submission we suggested the necessary scope for this standard (in answer to q7 and 8):

"Yes, this will be important to enable the safe and efficient connection of DER. We believe that some of the crucial features in this area are: a DER installation register, DER communications interface, protocol and capability in remote monitoring and control capability.

Also, just having a device pass the certification because it has the required feature is not enough. The actual device functions need to be enabled and the set points must be correct. There needs to be a process to enable this and verify this.

Using the example of EV charger management, current industry standard (SNZ6011) recommends using OCPP protocol for charger management, but there is a lack of details on the implementation of the standard and the minimum functionalities and interface requirements. Also, the OCPP variants across different product models mean that it is difficult to create a common platform to enable a standard communication interface."

"WEL believes that engineering standards should be considered for DER remote connection interface and demand response interface and protocols. Consideration should also be given to how this standard is verified in practice.

Up to date DER information must be readily available to all participants who reasonably require it."

4) Review Part 6 prescribed maximum fees para 8.74-8.78

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

WEL submitted in September 2021 that the prescribed minimum fees need urgent review. These fees have not been amended since 2014 and are resulting in other customers cross subsidising the work distributors undertake to approve connection applications. Inflation adjustment since 2014 would be the bare minimum change.

The way the fees are prescribed in Part 6 does not allow for any annual changes in underlying cost for assessing connection. It also does not allow for any regional specific complexity that may impact the cost of assessing the connection. Both the size and the technical complexity of the specific network area where the DG will be connected impact on the cost of assessing a DG connection.

5) Smart product standards – in particular EV chargers para 8.82-8.95

The Authority rate this as a high priority with implementation in 1-3 years.

While the Authority has not asked any specific questions about this topic, we provide the following feedback:

WEL agrees with the Authority's list of features of smart products (para 8.85).

Our view is that even with active management of EVs there will be significant investment required to supply the increase in demand.

WEL's submission in September 2021 included the following information which is still relevant to this consultation paper:

> While DER will be a critical component for New Zealand to achieve our decarbonisation goals, unmanaged DER has the potential to drive significant cost into distribution networks (and ultimately consumers). The impact of customer owned DER is likely to occur mainly within LV networks and have localised constraints. WEL commissioned a study which estimated that unmanaged electric vehicle (EV) charging on our network would require an additional $700M expenditure on our network by 2040. However, it is believed that with effective management, and the competitive procurement of flexibility services, this expenditure can be significantly reduced.

WEL agrees with the potential for DER and TOU pricing to flatten peak demand. WEL has introduced EV tariffs which are working quite well. Further the uptake/pass through by retailers of these distribution cost reflective tariffs is surprisingly high.

WEL's impression from the Issues Paper is that the Authority's is focussed on the 'performance' of EV charges. We suggest performance implies 'reliability' when the Authority should be thinking about the 'functionality' of the chargers. This reliability performance focus was also evident in EECA's consultation on mandating EV charges. In our view 'performance' equates to efficiency and efficiency occurs in the electric car and not in the charger. The charger is just an AC switch – the functionality of this switch is critical. The charger's conversion of AC supply to DC could be a performance/efficiency issue and could be rated using EECA's Energy Star ratings to demonstrate the efficiency of the actual charging.

WEL suggests the list of the requirements for EV chargers in the UK should be the minimum requirements for NZ (para 8.92). Additional considerations are:

- the functionality of demand side response and demand management are different
- electricity supplier (i.e., retailer) interoperability is ok but it is also relevant to have interoperability with 3rd parties (e.g., flexibility buyers)
- safety provisions are an absolute requirement
- a smart EV charger should include measuring systems – should include an app or front-end system to get reporting
- the EECA survey (a few months ago) is also relevant for this topic.

WEL agrees with the other requirements for charging points (para 8.93) which are important to ensure we don't want to end up creating a new peak demand at 10pm.

In addition, WEL strongly recommends residential charging points must include dynamic load control so that the household demand can't/doesn't exceed the supply rating for the household switchboard (standard household = 63AMPs and one EV charger is 32 AMPs). The minority of charge points currently being installed have dynamic load control.

WEL's recommended priorities for smart product standards are to:

1. mandate smart EV charging – and update the functionality of the existing charging infrastructure; and
2. require dynamic load control for domestic EV charging installations – this is not a huge cost but would improve safety and the customer experience.