SUBMISSION ON THE ELECTRICITY AUTHORITY'S ISSUES PAPER:

UPDATING THE REGULATORY SETTINGS FOR DISTRIBUTION NETWORKS

28 FEBRUARY 2023

vector

Vector's highest priorities for this workstream

This is Vector Limited's submission on the Electricity Authority's (the Authority) issues paper on *Updating the Regulatory Settings for Distribution Networks* (the Issues Paper) released in December 2022. We acknowledge the Authority's virtual engagement with Vector on 24 January 2022 to discuss this consultation. Vector Metering has provided its own submission.

This submission provides an overview of Vector's Symphony strategy to help realise our vision of *creating a new energy future* – a digitalised and decarbonised future for New Zealand, maximising affordability for our consumers. It responds to the Authority's consultation questions around the themes of ensuring equal access to data and information, market settings for equal access, capability and capacity, operating agreements for flexibility services, and standards for distributed energy resources (DER).

We are highly supportive of this workstream and urge the Authority to increase resourcing to enable it to be progressed as a matter of urgency. However, some of our priorities do not necessarily align with those identified by the Authority. In summary, we believe the Authority urgently (within the next two years) needs to update regulatory settings to activate the following recommendations:

1. **enable and ensure commercial access to network operational data for electricity distributors, and work with the Commerce Commission to ensure distributors are adequately funded for the access to and analysis of that data**
2. **enable visibility to electricity distributors of the installation (e.g. location), characteristics and operating behaviour of all DER on distributors' networks, particularly electric vehicle (EV) chargers**
3. **provide distributors with emergency management powers, similar to Transpower's under Part 8 of the Code, for the protection of the distribution network as the number of DERs increases. With more DERs operating, distribution networks will increasingly need to be operated similarly to the transmission network, and distributors will need sufficient powers to do so – especially in emergency situations**
4. **enable distributor coordination of the operation of DER under the management of third parties, particularly EV chargers, to ensure the operation of that DER remains within the physical and power-quality limits of the low-voltage distribution network**
5. **mandate smart and safe EV charging standards, including off-peak charging by default and randomised delayed return**

The latter three points above are not substantially addressed in the Authority's Issues Paper, yet are an area of significant focus for distributors and other parties in the electricity industry, wider energy sector, and adjacent sectors[1]. We provide more detail on these recommendations in the body of this submission, primarily in the discussion on operating agreements.

The introductory comments that follow introduce Vector's Symphony strategy, explain how the role of the distributor will evolve in coming decades, and provide some of our relevant learnings from the recent extreme weather events. The remainder of the submission then addresses each of the Authority's key focus areas. We have also provided 'call-out' boxes in sections we believe are worth emphasising, in the context of this consultation.

We are happy to discuss any aspects of our submission with the Authority. Vector's contact person for this consultation is:

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[1] See, for example, the insights paper recently published by the FlexForum on making better use of distribution network capacity, referred to in the next section of this submission.

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Vector's Symphony strategy

Vector is well-positioned to enable decarbonisation in New Zealand, the Asia-Pacific region, and globally. We are guided by our vision of *creating a new energy future*.

Despite the challenges of today, our integrated Group strategy we call Symphony is preparing us for the opportunities of a decarbonised future.

Symphony aims to transform the traditional one-way energy chain into an intelligent, multi-directional energy system that gives consumers greater choice and control. Fundamentally, it is about creating a decentralised energy system that opens up future possibilities, enabling decarbonisation that is consistent with reliable and affordable energy and technology solutions for consumers.

Consumers are demanding cleaner, more reliable, and more affordable energy. We are taking critical steps to transform how the energy industry operates to help deliver this aspiration. We seek to transform the energy sector by using data to redesign how energy investments are made, and how energy is managed, delivered, and consumed.

We are actively developing solutions to enable energy transformation, including partnering with other organisations where this would help us maximise opportunities and achieve our common goals.

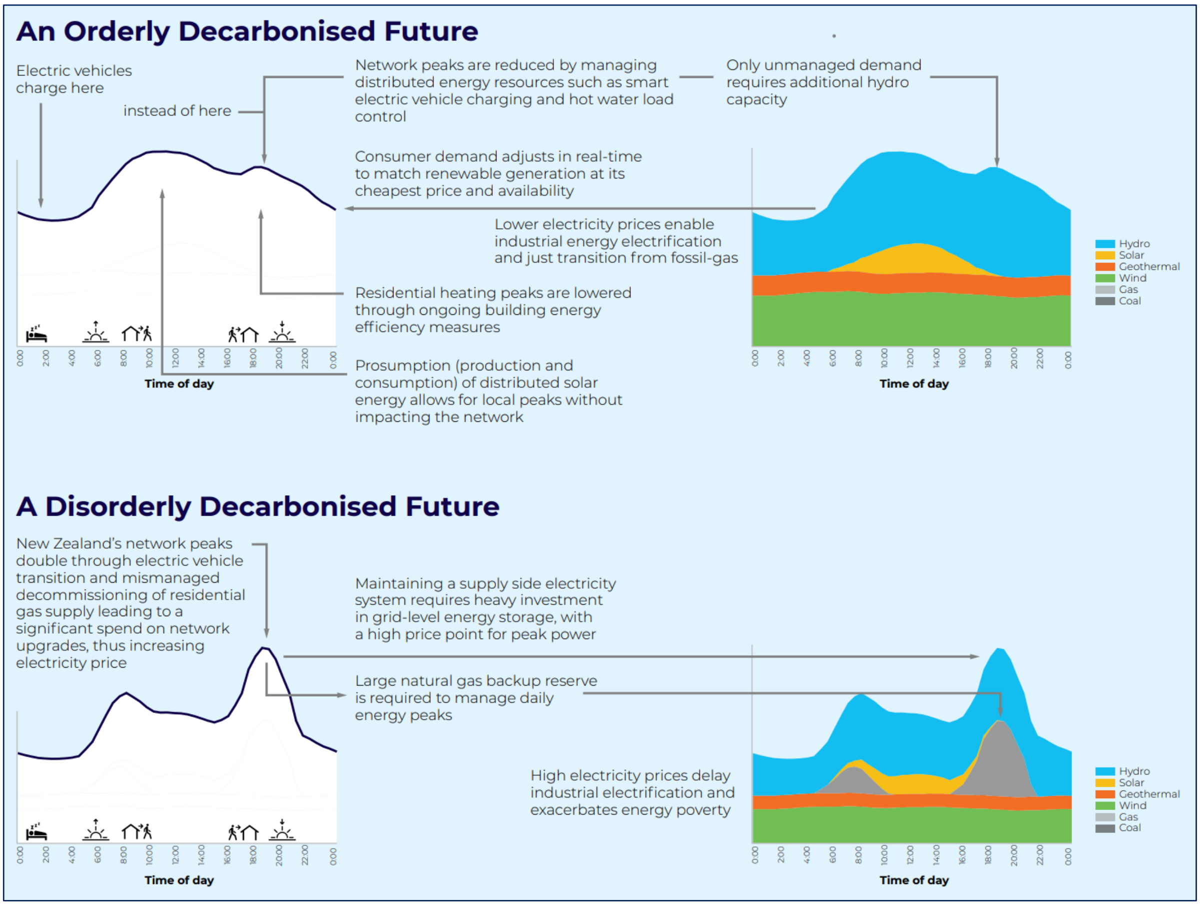
At its heart, Symphony aims to efficiently minimise future network costs

Vector's *Taskforce on Climate-Related Financial Disclosures* (TCFD) for FY2022[2] presented two potential scenarios for the future: "orderly decarbonisation" and "disorderly decarbonisation". Graphical illustrations of these scenarios from the TCFD have been reproduced below.

The crux of the difference between the two scenarios is how flexible energy resources are managed and orchestrated, to limit their impact on the magnitude of new network investment or expansion that is required. The differences between the two have significant implications for our future electricity system and, ultimately, affordability for consumers.

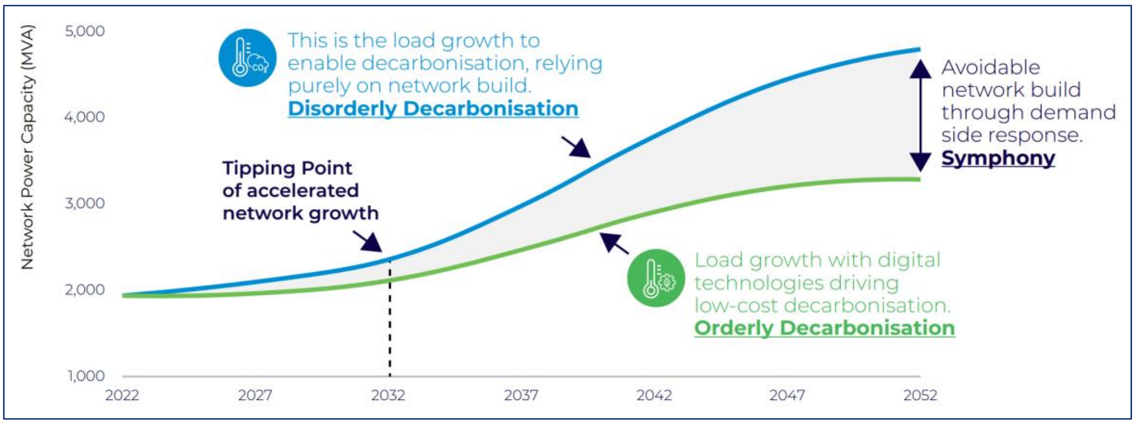
The heart of Symphony is enabling the orderly decarbonisation of New Zealand's electricity system, at minimum costs to our consumers.

[2] Available online at https://blob-static.vector.co.nz/blob/vector/media/vector-2022/tcfd-report-2022-vector-limited.pdf



The *disorderly decarbonisation* scenario models electricity growth with EV uptake, electrification of industry, transition from fossil natural gas to electricity, and population growth. Distribution network growth is driven by an increase in peak load, for example with EV charging clustered around peak hours. From a network perspective, our key challenge is ensuring we can meet peak demand while maintaining a transition to renewable energy generation, which is variable by nature. Investing in assets which do not reconcile these factors is likely to result in inefficient allocation of capital.

The *orderly decarbonisation* scenario models electricity growth with the assumption that all EVs, hot water load, and battery systems are orchestrated in a way that minimises peak demand, and hence the size of the network required, thus allowing for increased electrification of energy needs at minimal cost to consumers.



The graph above shows the difference in network capacity required to meet demand when demand management (such as smart EV charging) is utilised, versus when it is not. This shows that the peak experienced by our network could more than double by 2050 in the absence of smart EV charging and other DER orchestration –increasing from 2000 MVA today to well over 4500 MVA by 2052. With this higher peak demand comes a need to invest in more network capacity – and much more. Inefficient capital investment increases electricity bills for all electricity consumers.

This increase in peak demand, however, can be reduced significantly by demand management (such as smart EV charging) – the impact of which is represented by the difference between the blue and green lines. Demand management could bring the expected peak demand on the network down from ~4500 to 3000 MVA by 2050 – a significant reduction in the increase in peak demand growth forecast under the counterfactual. This graph, and further analysis related to the challenges and opportunities associated with our transition to net zero, are reported more fully in Vector's FY2022 TCFD.

These scenarios reveal the importance of decarbonising the energy system in the most efficient, resilient, and cost-effective manner possible. A disorderly decarbonisation transition would require significant network investments that would increase costs for consumers and exacerbate existing inequalities.

Our strategic intention is to run our network in as smart a manner as we can, and only invest in network augmentation where absolutely necessary. An orderly transition should ensure that only the right amount of capital, being a scarce resource, is deployed. Assuming regulatory settings provide the right investment incentives (where, for example, returns are commensurate with risk), an orderly transition will ensure that contributors of capital receive appropriate returns and consumers pay appropriate prices. Therefore, the growth in electricity assets under an orderly transition can be considered an opportunity.

A disorderly transition results in more scarce capital being deployed than is required under the orderly transition, which is inefficient. While contributors of capital may still earn appropriate returns under a disorderly transition, the same cannot be said for consumers. Consumers would pay higher prices per unit of energy consumed under a disorderly transition when compared to an orderly transition to effectively fund the returns required on the excess deployed capital. This is a risk, as it could attract intervention by regulators and/or the government.

The conclusions of the Boston Consulting Group's (BCG) recent report, *The Future is Electric*[3], support the ambitions of our Symphony strategy. BCG concluded that a "smart system" scenario, in which flexible resources are operated in such a way as to avoid opex and capex in generation and distribution/transmission infrastructure, can save $10bn in costs to consumers out to 2050.

[3] Available online at https://www.bcg.com/publications/2022/climate-change-in-new-zealand

In a Symphony world, the distributor's role will have evolved significantly

In a future where millions of devices connected to distribution networks are being used every hour of every day to provide services to multiple parts of the electricity value chain, the role of the distributor will have evolved significantly. Core tasks will remain, but new capability in advanced distribution system operation (DSO) will be required. The evolving interrelationship between the growing penetration of DER on our network, the operators (managers) of that DER, and the distributor, is therefore of critical interest to us.

The FlexForum's recent insights paper[4] describes the evolution required to unlock system-wide benefits to DER owners and consumers more generally:

> Diversity of demand, and predictable one-way flow patterns on networks, have meant it has not been necessary to monitor or manage capacity for consumption or generation on a connection-by-connection basis. Maintaining power supply and quality has been straightforward for distributors to achieve under a 'set and forget' basis due to stability and predictability in network use patterns and flows on their networks over time. …
>
> Continuing to use a conservative static, set-and-forget approach to allocating network capacity will likely lead to restrictions on connection of DER (eg, electric vehicle (EV) chargers and solar systems), and/or reductions in opportunities to maximise the value of flexible DER, and could drive the need to invest in a larger network, sooner. Capacity restraints could also inhibit the conversion of non-electric processes to electricity. …
>
> Flexible DER can, with the explicit consent of consumers, be used to support the operation of the network by providing extra ability to defer or avoid the provision of upgrades to network capacity. Equally, use of flexible DER on local networks can mean that fewer transmission lines or power stations need to be built and operated across Aotearoa New Zealand.

The FlexForum's paper further discusses how the role of the network operator will need to become much more sophisticated and dynamic, as behaviour on the network becomes less linked solely to predictable demand:

> More routine use of flexible DER, especially as part of the national system, will change the patterns of network use, including potentially creating real or perceived localised network congestion and performance challenges. (Perceived congestion is a result of adopting conservative set-and-forget design parameters without having visibility of actual network capacity and loading in real time.) The capability to make better use of available network capacity will support using flexibility for network, system, and market purposes. …
>
> The demand for network capacity on the transmission network, and on local distribution networks, changes every hour of every day due to the combination of what households and businesses are doing and whether the sun is shining or wind blowing, how cold or hot the temperature is, and what planned or unplanned outages of network capacity have occurred.

Before beginning to propose potential new tools in the distributor's toolkit for managing this future world, FlexForum continues with a clear, succinct problem definition that aligns with our own concerns (our emphasis added):

> **Flexible DER will have a growing impact on network operation as it increasingly participates in national markets for energy and ancillary services and is**

[4] Available online at https://www.araake.co.nz/assets/Uploads/FF-insights-making-better-use-of-available-distribution-network-capacity-31-January-2023.pdf

> **dispatched by Transpower, the System Operator** (especially after the introduction of Dispatch Notification product in April 2023).
>
> Distributors can manage sudden falls in load. **Restoring load (including after a period of load control) requires more careful management**. A fall in wholesale prices, due to increases in wind or solar generation across a part of Aotearoa New Zealand, could see many distributed batteries, EV chargers and smart hot-water cylinders being dispatched on by the System Operator. Similarly, large numbers of DER, such as household batteries, are already being armed to respond at short notice to a fall in system frequency on the grid.
>
> About every five minutes of every day, the System Operator uses security-constrained economic dispatch, via the SPD tool, to work out which power stations to run, which flexible load to dispatch on or off, and which response resources to arm for reserves.
>
> However, by design, **this tool can only see as far as the grid exit point (the boundary between the transmission network and distribution network) and has no visibility of the security and power-quality constraints on the distribution networks**. As with the transmission grid, **the capacity available on distribution networks can change materially at short notice** – for example due to storms, car versus pole outages, every-day network switching and planned outages.
>
> To enable flexible DER to provide services to national markets in a way that keeps distribution networks safe and stable, and maintain power quality to consumers within legislated limits, **distributors will need to provide operators of flexible DER with network access that represents not just maximum physical operating limits, but possibly also physical limits on the rate-of-increase of demand or output that the network can handle to avoid creating unmanageable surges** (which could happen if the wholesale price, or the system frequency, suddenly drops or increases).
>
> **With more DER operating, distribution networks will increasingly need to be operated similarly to the transmission network.**

The FlexForum's paper highlights just how important it is becoming for distributors to actively oversee the operation of flexible DER on their networks. This would ensure that the DER only operates within the physical and power-quality limits of the network. As such, we had expected this relationship to have been given a greater focus in the Authority's Issues Paper.

Enabling advanced distribution system operation is a key priority for Vector

As noted by the FlexForum, operating the distribution network will become increasingly similar to how the transmission network is operated by Transpower. Parties operating DER on our network will become increasingly analogous to the generators operating on Transpower's network. Our relationships with these parties will need to be managed in a similar way.

This is a very high priority for us and should be for the Authority as well. A number of building blocks need to be in place to enable the best outcomes for consumers in this energy transition. In this submission, we describe and propose what these building blocks should be – supported by the expert reports accompanying this submission.

Extreme weather events have brought relevant issues sharply into focus

By the middle of February 2023, many parts of the North Island had had their wettest start to the year on record. In Auckland, pluvial (flash) flooding in the last weekend in January significantly impacted local infrastructure, bringing large parts of the city to a standstill. This was followed two weeks later by Cyclone Gabrielle, which brought extremely high winds to the North Island, and caused significant and widespread damage to a number of distributors' networks in the area, including Vector's.

There is general consensus that such events are likely to become more common in future.

Clearly these events have brought into stark focus the criticality of vegetation management to reduce the occurrence of outages. While this is an area outside the Authority's remit, it clearly impacts the reliable supply of electricity and the Authority could play an important advocacy role for the sector.

However, as set out below, these events have also served to bring several issues related to this consultation sharply into focus, highlighting both the urgency of addressing them in the interest of public safety, and the benefits that will result. These are set out below.

Identifying the location of faults and extent of outages

In the initial stages of these emergencies, we sought to identify which consumers had lost power and when that occurred. This provides valuable information to assist the field response crews.

During our response to Cyclone Gabrielle, outages were occurring across our entire network, affecting both our high-voltage equipment (where we have sensors on equipment to help identify outages) and the low-voltage network (where we typically rely on field crew inspections and customer calls to identify outages). The high wind speeds, and impediments to road access, meant we were unable to undertake physical inspections, so we sought to utilise smart meter data.

We worked together with Intellihub and Vector Metering to arrange a once-daily overnight report of non-communicating meters as a new source of data to assist with the storm response. Previously we had worked with Chorus to receive information about whether a consumer's fibre internet terminal in their home is powered as an indicator of whether a home has power. The final tool available to us is to send a 'ping', or a simple message requesting a response from the meter to see if it is online, to the subset of smart meters in the field that have that capability. There are limits on how many of these ping messages can go out at once, due to constraints on the communications platform for the smart meters.

We combined these sources of data together to help us identify low-voltage outage issues across the network. This proved valuable in improving our communications to customers, identifying outages in areas where customers may not have been able to contact us, and managing the workload for our field crews. In some cases, we called specific customers to check if their power had been restored so that we could close out jobs before our field crews spent the time travelling to those locations and knocking on doors, allowing them to be sent to an area that was still without power.

In future, once distributors have full, commercial access to high-quality network operational data (including meter ping), we will be able to understand more clearly and quickly where the causes of non-supply in our networks are – including more rapid diagnostics on secondary issues that only become apparent once primary issues have been addressed. At the minimum, default access to meter ping and non-communicating meter information in emergency situations will be critical.

Providing accurate information to consumers on their status of supply

With commercial access to real-time data including meter ping, distributors will be able to give much more accurate information to consumers on the status of their supply – being clear about which connections are definitely live, and which are not.

Issues with access to that data, and the accuracy of the data we received from both the meters and other sources, meant that some of the information we provided consumers was at times inaccurate.

Providing safer and more rapid restoration of supply

After a prolonged period of outage, every single hot water cylinder in a street will be cold. In future, household and EV batteries may have been drained as well. This creates a risk that, as power is restored to a home, street or suburb, these large loads all attempt to draw power at once – creating a local peak far in excess of what the network is designed to cater for. This has the potential to overload the network, which may at that point have significantly limited supply. We understand this issue occurred on several networks around the region, driven primarily by hot-water loads, making the process of restoration more complicated, prolonging outages and frustrating consumers.

Further, with the increased participation of DER in national wholesale markets, these DER could be attempting to undertake actions (or be dispatched by the System Operator) which could impede carefully-managed network restoration and put public safety at risk. This has not been contemplated in the market design to date.

We have therefore identified the ability for the distributor to orchestrate DER in emergency situations, and especially those DER under the direct control of other parties, as a primary concern for load management on our network. As discussed later in this submission, we are developing our initial load management protocol to address this concern and provide a better experience for our consumers. This applies to both everyday network operations – ensuring DER only operates within the physical and power quality limits of the network – and emergency response, because if a large number of DER are responding to a national market signal that synchronises their behaviour, our local network safety equipment may respond and cause an unplanned outage for all consumers in that area.

A critical consideration in natural disasters such as Cyclone Gabrielle is the distinction between *local* system emergency events and *national*, grid emergencies. The cyclone wreaked havoc on multiple distribution networks around the North Island, but (with the exception of Hawkes Bay) did not reach grid-level emergencies. In a future world with widespread DER we cannot rely on weather events having to reach grid emergencies before one party can start directing efforts of all participants to restore power for the masses. It is imperative that EDBs also have this power to direct the activities of all parties managing DER so that power is restored to the majority as quickly and safely as possible – not just to those owning DER. If distributors do not have the power to issue directions, then, as mentioned above, power may keep coming on and off as too much load is brought back on too quickly and without proper coordination.

Further, in some circumstances our network design allows us to temporarily re-route power or “back-feed” customers from other areas of the network that have not experienced storm or other damage. Re-routing service to customers depends on the capacity and loading on the back-feeding network assets. Orchestration of DER could provide additional buffer on these backup systems, enabling us to restore customers more reliably through these back-feeding arrangements while network infrastructure is repaired.

With better knowledge of where DER are, and powers to orchestrate the actions of DER-managing parties in emergency situations such as these (analogous to the powers Transpower has in a grid emergency under Part 8 of the Code), distributors will be able to manage restoration more quickly leading to better outcomes to consumers.

Equal access to data and information

Vector now has access to consumption data for most consumers on our network

Vector agrees that a fully digitised energy system in which key data can be seamlessly accessed and exchanged by authorised parties will help unlock and optimise the full potential of DER for our network and consumers.

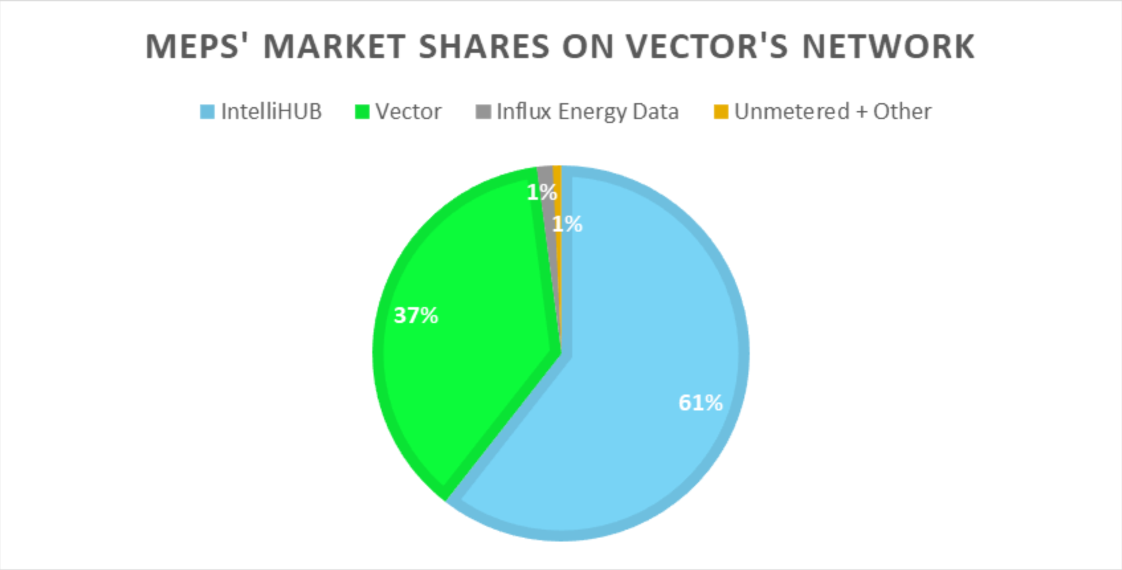
We support the overarching desired outcome of this workstream – for distributors and flexibility traders to have equal access to the data and information they need, supporting the transition to a low emissions economy and for the long-term benefit of consumers.

Vector is now positioned to receive half-hourly consumption data for virtually 100% of the ICPs on our network. We describe below the effort that has been put in to gain access to consumption data over the past two years, and the resulting outcomes.

Vector's experience in accessing half-hourly consumption data

Over the past two years, Vector has contracted with retailers on our network for the supply of consumption data for almost 100% of the ICPs on our network. We are currently receiving monthly data from retailers covering 86% of those ICPs.

Importantly, this has been achieved without Vector's regulated electricity business owning any meters on its network. As shown below (data current as at 1 February 2023), Intellihub owns the majority of meters on our network at 61%, while Vector Metering owns the next largest share at 37%.



Our journey to receiving consumption data began with the then new Part 10 of the *Electricity Industry Participation Code 2010* (the Code), which went live in 2013, including the new retailer-appointed MEP model. Under this model, retailers were initially either reluctant or unable to provide data to distributors. Some retailer-MEP agreements had restrictive data access terms and, in the latter half of the 2010s, there were extensive concerns by retailers around privacy and permitted uses of data if they were to share consumption data with any party, including distributors.

Code changes in 2016 designed to open up data flows did not work as intended. Some bilateral negotiations did occur prior to the DDA, but these did not unlock much data. In 2020, the publication of the *Default Distributor Agreement* (DDA), and its accompanying Appendix C, unlocked the door, but there were still limitations:

1. Rules prohibited data being combined with other datasets, reducing the usefulness of the data for network planning purposes.

2. The default delivery frequency was six-monthly.

3. The DDA solution did not consider the practicalities of MEPs liaising directly with distributors for data provision.

In 2021, the Authority mediated a solution between some members of the ENA and the Electricity Retailers' Association of New Zealand (ERANZ). However, this was not accepted by the Authority as a replacement to Appendix C of the DDA for various reasons. Despite this, Vector (and some other distributors) forged ahead with the mediated solution, including a specific Data Combination Schedule, agreeing to it with a number of retailers.

However, signing agreements did not mean data would start flowing – which the Authority had not anticipated. Different retailers have taken different approaches (e.g. direct provision by the retailer or provision via MEP), and actual implementation has taken longer than anticipated.

As of 1 February 2023, 99% of our ICPs are under data contracts, and we are currently receiving consumption data for 86% of ICPs on a monthly basis. We have received historic data back to 2017, giving us a complete five-year dataset.

Some of this data is provided directly by retailers and some via retailer's MEPs (requiring reimbursement for reasonable costs). Our preference is to receive data in EIEP3 format, but this is not always the case when received. Reformatting and cleaning the data, pre- and post-ingestion, creates a significant amount of additional work, and we still need to adjust the data to account for retailer switching and differences in the treatment of daylight savings.

We have learned a number of lessons in getting to this point, which may be helpful for other market participants, the Authority as it progresses this workstream, and the Commerce Commission which is currently reviewing the *Commerce Act 1986* Part 4 Input Methodologies:

- Executive support is essential to ensure sufficient investment in gaining access to, and realising the value of, this data, so that it is prioritised by the organisation and receives the necessary resources.

- We needed strong support from our commercial, legal, and regulatory teams to engage with retailers and MEPs. A signed Appendix C does not automatically equate to 'data in the door'.

- Distributors need to budget for the data. It will not come free of charge from all parties; some will require the reimbursement of reasonable costs. Cleaning the data and analysing it also requires significant investment; value can only be unlocked for the permitted purposes by teams of data scientists and engaged engineers with analytical backgrounds.

- Strict data governance, combined with the Combination Schedule, is critical. This gives confidence that the data will only be used as intended, and appropriate safeguards will be put in place.

- Deep consideration needs to be paid to data platforms, both from a storage and an analytics perspective.

- There is a vast quantity of data to manage and wrangle to create a 'whole of network' view.

- As our attention turns to accessing and using power quality data (PQD) and other operational data, distributors need to proactively define use cases and what data we need to support these, and to work with MEPs to tailor the services they are offering. To date, the focuses of MEPs' technology deployment, and retailers' end customer offerings, have been almost entirely on half-hourly kWh data. In our view, MEPs will need to evolve and innovate to deliver other forms of data for use by distributors.

Enabling access to and use of network operational data is urgent, and critical – now

Overall, in the context of our data journey, described above, we agree with some of the issues identified in the *Equal access to data* section of the Issues Paper. However, we have the impression that the Authority has not sufficiently appreciated the criticality of enabling access to and use of network operational data by distributors. This is absolutely critical to enabling distributors to evolve their capability in distribution system operation, efficiently allocating network capacity among network users and managing constraints. None of this will be possible without a high degree of visibility on our low-voltage (LV) networks.

As set out in the introductory sections of this submission, this is a critical issue, now. With Dispatch Notification being introduced in April 2023, distributors will be needing to ensure that all forms of DER operating in the spot market stay within the physical and power quality limits of the network (an issue we address later in this submission). Doing this efficiently, and without undue conservatism, however, requires a high degree of visibility on our LV network.

We make the following additional comments on data access:

1. **Immediate changes** – we consider there are some issues that can be resolved quickly and without the need for further consultation. These include:

    a. <u>Replacing the Data Template (Appendix C of the DDA) with the ENA/ERANZ version of the data agreement ("replacement Data Template").</u> We suggest further amending the replacement Data Template to allow for a time when real-time data (or near to) can be provided, rather than just the monthly provision of consumption data. This would avoid the need to re-amend the replacement Data Template. Vector adopted the ENA/ERANZ amended version as our Data Agreement, and (as set out in the call-out box above) with considerable effort and resourcing, we have been able to access up to 99% of the consumption data on our network. We suggest the replacement Data Template be introduced into the Code in a way that leaves existing contractual arrangements valid and in force so that further efforts on Vector's part in this area will not be necessary.

    b. <u>Amending the Code to provide that MEPs must contract directly with distributors, to provide consumption data and PQD for permitted purposes, without the need for retailer permission.</u> However, for the reasons noted at paragraph 3 below, we think Code amendments that would extend the changes to flexibility traders should be introduced later.

    c. Although we do not consider a model set of privacy provisions for retailer terms to be necessary, should the Authority decide to adopt this approach, we favour the non-prescriptive approach seen in retailers' terms currently. It is important that privacy provisions in retailers' terms allow the use of data for legitimate network needs over time, rather than the more prescriptive contractual provisions contained in agreements at any point in time such as the Data Template. This will help to future-proof the privacy provisions, rather than require constant updating.

2. **Data requirements** – we disagree with the Authority's proposed timeframe of five years for addressing the short-term data requirements noted in paragraph 4.2. Vector considers this is both required and addressable within the next three years. Distributors will need more data – more granular, more frequent and more sub-types of data – particularly PQD, sooner. As discussed earlier in this submission, the unprecedented weather events experienced so far in 2023, which caused widespread flooding and power outages, demonstrated the need now for immediate or near real-time outage or event data (a subset of PQD). As climate change continues to bring inclement weather, the need for this type of data will only become more urgent. Further, without high levels of LV network visibility, distributors will be unable to allocate network capacity to DER dynamically, likely having to revert to less efficient, static management.

3. **Further consideration** – we offer qualified support for equal access to data for flexibility traders – in due course. The current low levels of DER in the marketplace, with few flexibility traders, allows ample time for a proper consideration of important issues before equal access is enabled for flexibility traders. These issues include:

   a. **Data protection and security –** flexibility traders could range from small new entities to large retailers. The latter will have secure, well-established systems and processes to handle and protect customer data. The former may not. The wide range of possible flexibility traders needs to be considered so that appropriate and adequate safeguards are put in place for the benefit of consumers.

   b. **Permitted purposes –** relatedly, the purposes for which flexibility traders may use data will depend on the scale and size of a flexibility trader's operations. Again, appropriate safeguards need to be put in place to ensure data is only used for a set of permitted purposes. In our view, this requires careful consideration and consultation, similar to the processes followed in the development of the DDA Data Template.

   c. **Code obligations –** any Code obligations to be placed on flexibility traders also require consideration. Flexibility traders are currently not "Industry Participants" under the Code (although aggregators are, at least in the context of wholesale market participation / Dispatch Notification). However, the Code is light with respect to obligations on "aggregators". We believe this requires further consideration, alongside the data access Code changes proposed in the Issues Paper in relation to flexibility traders.

4. **Other high priority issues** – understanding what PQD is available now and what could be made available in the future is another critical area requiring focus. To a large extent, the availability of PQD depends on the age of the meters, the characteristics of the metering fleet, and the metering technology on a distributor's network, which tend not to be visible to distributors. Distributors need transparency on their networks, and the availability of PQD is critical to enabling this. Use cases for PQD need to be considered and refined based on this knowledge. Although Vector entered into a small trial (with 50 ICPs) with two MEPs to better understand usage requirements, larger trials and more data are needed to better understand relevant issues. Some of the things we want to understand are:

   a. the volume of data required
   b. the frequency with which data can be provided
   c. what subsets of data can be provided
   d. the granularity of the data that can be provided, e.g. understanding whether the data is 'instantaneous' or 'average'.

Vector would be happy to work with the Authority to help enhance its understanding of why and how critical PQD is to the future operations of our network.

The Authority could address the issue of availability of PQD in a couple of ways:

1. Requiring each MEP to disclose (annually) to the relevant distributors information on the MEP's metering fleet, age of meters, investment in metering technology, and the PQD available in each distributor's network.

2. Supporting trials like that undertaken by Vector to further the understanding of data availability and use cases. This would include either direct or indirect support for investment or funding, given that PQD is likely to be significantly more expensive than consumption data. The long-term benefits of this data for consumers are also likely to be significant.

***Q1**. Do you see the 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?*

Vector broadly agrees with the objectives of the UK's Energy Data Taskforce, which are intended to unlock the value of customer actions and assets and deliver interoperability (where necessary) for the long-term benefit of the energy sector and consumers. However, we do not see any significant value in the Authority commissioning independent reviews into the merits and practicalities of implementing the recommendations of this Taskforce.

We note that several of the recommendations by the UK Taskforce are already being explored or implemented in New Zealand, e.g. greater access to smart meter data, registration of energy assets, and heat maps. There is continuing, if not increasing, momentum and collaboration amongst New Zealand industry participants in progressing similar initiatives; we would not wish to see these stifled by regulatory prescription at this stage of market development.

We bring to the Authority's attention a recent (December 2022) assessment by Australia's Energy Security Board (ESB) of the UK model,[5] which has serious misgivings about its complexity (our emphasis added):

> **Challenges introducing a distributed data services network - UK Energy Digitalisation Taskforce - Open Data model**
>
> The UK model provides a useful case study of the greatest complexities in a distributed or network model.
>
> The UK Energy Digitalisation Taskforce aims to unlock flexibility within the UK's energy system and realise the value of energy data sets. Its approach centres around long-term investment into the creation of federated data services model, in which data is treated as open by default. One of its key goals is to make datasets more visible via a single, searchable platform which connects requestors directly to custodians.
>
> This is an ambitious and highly expensive undertaking, requiring investment across all data holders. The road to this model has been over five years in the making, which required the UK to ensure that goals of different stakeholders were first clearly aligned, with a shared purpose, direction and transparent governance which needed to be demonstrated in order to receive the scale of investment required.

[5] Available online at https://www.datocms-assets.com/32572/1671059508-esb-data-services-delivery-model-consultation-paper-december-2022.pdf

> The development of a distributed data services model was partly opportunistic, as there was a window of opportunity to integrate data-sharing and digitalisation obligations when operator and regulator licences were being renewed. While this approach has been effective at increasing data sharing due to these imposed incentives, <u>this is a heavy regulatory burden which has taken a long time to develop costly new arrangements</u>. This model is also struggling to meet its current goals, as coordination between the bodies has been lacking, making sharing and access difficult, as well as limiting ability to manage data across providers.
>
> <u>Therefore, the UK is now introducing a centralised body to provide data coordination, to streamline data-sharing standards, platforms and processes and manage compliance.</u> Most distributed data systems (like the Consumer Data Right and Open Banking) require onerous coordination, standards, and registries to ensure data remains interoperable and compliance is managed.
>
> The UK undertook this approach starting from a different set of energy data arrangements than Australia. The UK lacks much of the existing data sharing infrastructure Australia already has. The UK has no central metering database like MSATS [*Market Settlement and Transfer Solutions*] or related existing data exchange processes. Because of this, <u>the initial open data obligations have focused on networks, requiring them to publish network performance data. Being able to analyse and access meter data remains a priority in the UK but was considered harder to implement as it would require data to be released by retailers</u>.
>
> For Australia to implement a similar data services network model, new regulatory requirements compelling networks and retailers to release data would be needed, similar to the UK. <u>These requirements would likely take time to develop and impose a cost burden on these businesses…</u>

We encourage the Authority to review the Australian ESB's comments in considering whether to undertake their proposed reviews. We also encourage the Authority to discuss these issues with the ESB and/or the team implementing/revising the UK model, where necessary and appropriate. While there is value to be gained from the UK model, New Zealand could well benefit significantly from adopting the model's elements that would best support and facilitate proposed new arrangements (the best first steps) while avoiding its complexity and additional regulatory burden for regulators, industry participants, and consumers.

In addition, we are inclined to agree with the ENA's submission, which does not see value in pursuing recommendations made by a working group from an entirely separate jurisdiction. We endorse the ENA's proposals that:

1. If the Authority considers the objectives of the UK Taskforce to be consistent with its own objectives for the New Zealand electricity market, then the Authority should establish an appropriate taskforce.

2. The above taskforce should work from first principles to develop recommendations that work in the context of the New Zealand electricity market.

Should the Authority still decide to undertake a review of the UK model, we suggest that its scope be streamlined so their findings and recommended actions can be delivered in a timely manner to support ongoing reforms in New Zealand.

There is a strong emphasis in the Issues Paper on access to smart meter data for distributors and flexibility traders and the timeliness of data delivery to unlock and optimise the value of DER. The proposed review could focus on actions in the UK model that would greatly facilitate the achievement of these objectives.

We further encourage the Authority to take account of impending arrangements in New Zealand that would help facilitate secure (and ultimately) instantaneous access to data such as the introduction of a Consumer Data Right (CDR) in the energy sector along the lines of the Australian CDR – which are not available in the UK.

***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?*   ***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?*

Vector makes the following points in response to **Q2**:

1. Amps (current) and vars (reactive power) should be added to the Authority's list of PQD data.

2. We prefer instantaneous rather than average PQD because one of its primary use cases is to improve our network connectivity mapping, which includes identifying which network assets ICPs are connected to, including which phase they are connected to of the 3-phase power system. <u>Synchronised, instantaneous readings would enable this network connectivity mapping, whereas averaged data would not</u>. These subsets of PQD, particularly instantaneous voltage, current, and phase angle, will also be used to support and enhance public safety measures, allow for deeper insights into customer behaviour and improve our customer service monitoring. For example, it will enable us to analyse how well we are meeting our service obligations to customers, particularly in relation to voltage (+/-4%).

3. We support the adoption of power quality standards similar to those being considered in Australia, which also support 5-minute market settlement. A standard would ensure data consistency across networks and consistent provision of data to industry participants so that the overall transaction costs of negotiating PQD agreements are lower.

4. PQD, which Vector often refers to as network operational data (NODs), is in our view, different to real-time outage information or Event Data. As we note in our overall comments at the start of this section, outage or Event Data will be required instantaneously or in real-time, for public safety reasons and enhanced customer service and experience. The sooner this data can be delivered, the better.

With regard to key distributor data needs and prioritisation (**Q3**), we propose the following changes or additions:

1. Understanding the availability of PQD needs to be a high priority, for the reasons noted above. PQD is still a relatively new data set for the industry. Investment by several parties will be required to ensure the true value of this data is utilised for the long-term benefit of consumers. Investment decisions around the value, volume, and types of PQD needed will drive the use cases for PQD. The importance of this understanding through exploration and investigation cannot be underestimated.

2. As above, we offer qualified support for equal access to data for flexibility traders, but in the medium term, for the reasons also noted above.

3. We consider the visibility of customer information on the location, size, and functionality of DER (non-exporting) on the LV network should be of high, rather than medium, priority. This is because the value of this information is highest during the early phases of DER uptake. As the Authority notes in the Issues Paper, in relation to efficient decision making, if a distributor is approaching capacity constraints in a particular area where there is high DER uptake, then a small upgrade to equipment may be appropriate, but if the DER uptake in the area is low,

then the more efficient decision may be a larger upgrade to accommodate expected EVs and electrification over the long term. In the early days, during low DER uptake regionally and nationally, it is still important to know which specific neighbourhoods already have higher DER uptake, so this can be factored into network upgrading decisions. Without this visibility, decision-making will not be optimal as distributors may (reasonably) assume that DER uptake is low across the board. This can be addressed relatively easily by amending the electricity registry field to require this information, and we suggest this be made a high priority.

4. We provide our feedback on the options to improve data accessibility in our overall comments and in our response to Q4. The Authority would be aware that Vector has now successfully obtained most of the consumption data on our network, with the remainder contractually secured for provision. We therefore consider other options, such as the development of privacy disclosure terms, to be unwarranted. These would unnecessarily divert resources and time from more important areas of work, for example, the need to understand and support the availability of PQD.

5. Finally, with respect to the prioritisation of "real time non-aggregated Consumption Data and PQD (Data need 3)", we suggest that funding should be made available to explore the capabilities and limitations of MEPs (and their existing meters). As existing metering fleets reach their 'end of life', any replacements should have suitable specs for future needs. The time to explore what those future needs and specs might be is now, alongside funding considerations. A timeframe for when real-time, non-aggregated consumption data and PQD is needed is more likely 5 – 7 years, based on our understanding of when uptake of DER, and electrification, will accelerate. However, the groundwork for that data needs to be laid now.

***Q4**. Does this capture the key data needs for flexibility traders for them 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?*

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

Vector agrees that flexibility traders should have access to LV-level data that helps them "make informed business decisions to unlock the potential of DER". However, distributors must first gain access to the key data that enables them to understand and model their networks at the LV level.

Distributors are already starting to develop the tools and platforms to be able to share insights with flexibility traders connecting directly to a zone substation or GXP. But the ability to deliver insights or data on a granular, ICP-level will be limited until distributors are able to gain access to and integrate operational data from smart meters.

Additionally, different DERs will create or alleviate different constraints on the network. With an accurate network configuration map (which requires either access to PQD or doing a physical survey of the network), distributors could likely provide granular constraint information related to import-only DERs (such as smart EV chargers or hot water cylinders). Forecasting the capacity limits (kVA) of network equipment could be achieved with aggregated granular consumption data from smart meters. However, for DERs that inject onto the network (such as batteries, solar PV or V2G-capable EV chargers), capacity limits must be considered alongside voltage constraints introduced by these systems.

<u>Until distributors have gained access to the PQD from LV areas of their network and have integrated that data with physical network information, the information that can be provided to flexibility traders will be of limited use to them</u>.

Visibility of the location, size, and functionality of DER installed behind the customer's meter would be valuable to both distributors and flexibility traders. Again, in order for this data to unlock the potential of DER it must be considered alongside the physical network that it is connected to. This means that distributors would be combining this data with their network models to provide information about network constraints. In isolation, flexibility traders will not be able to make any useful assessments using PQD without an understanding of network topology, operational considerations, and investment plans.

Overall, there seems to be a misconception of the role flexibility traders will play in the Authority's description that access to LV-level data will:

> …help FT understand the drivers of network congestion. This enables flexibility traders to identify the areas of a network that will need upgrading before others and offer solutions accordingly.

We do not necessarily see flexibility traders as needing to understand the drivers behind network congestion. What they will need to understand is how flexibility resources may impact or benefit network congestion in localised areas. We also do not see flexibility traders actively identifying areas of the network that will be upgraded before others. Distributors have teams of people with this specific responsibility, and the technology, to make such assessments.

However, we are looking at how we communicate the forecasts for network upgrades to flexibility traders more effectively via our website, and in the asset management plans we are required to disclose annually.

***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?*

***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?*

Vector supports the proposed changes to the DDA Data Template set out in the Issues Paper. The Authority is aware that Vector adopted the ERANZ/ENA version as its data agreement, requiring the monthly provision of consumption data. We support this version becoming the replacement or new Data Template.

We further support amending the Data Template to make MEPs the default provider of Consumption Data. (*Note*: Data provision contracts would still be required between MEPs and Distributors, as MEPs are not party to the Data Template.) For this reason, <u>we support a Code change over amending the Data Template, to make MEPs the default provider of data</u>. This would significantly increase the efficiency of data transfers within the industry.

We think the Data Template ought to be set up to cater for a time when even more frequent data delivery (than monthly) might be desired. As we move closer to real time data provision, the Data Template can be amended so as not to need the further consent or agreement of the parties.

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

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

In response to **Q8**, Vector agrees that retailer permission is often needed before distributors can access both consumption data and PQD from MEPs – including our recent experience in attempting to access meter ping data after Cyclone Gabrielle. This has impeded, and continues to impede, the efficiency of data flows across the industry.

On **Q9**, we support Code amendments to clarify that MEPs must contract directly with distributors and flexibility traders for the provision of ICP data (consumption data and PQD) for permitted purposes. A Code change would override the terms of any metering contracts between retailer and MEPs, and remove any further barriers.

We agree though that further thought needs to be given to the set of permitted purposes for flexibility traders and to existing commercial arrangements and privacy protections before Code changes are made. We therefore support a two-step Code change: one to address the existing barriers to distributors accessing consumption data and PQD, and the second step to enable similar access for flexibility traders once the issues noted have been considered and/or consulted on.

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

Vector's preference is for a Code change, rather than a change to the Data Template to support the provision of PQD to distributors and flexibility traders. A Code change will override any contrary terms in existing metering agreements, and will extend to all relevant parties, whereas the Data Template only applies currently to retailers and distributors.

Although we support a Code amendment over Data Template changes, we consider the more pressing issue to address is understanding what PQD is available right now (in terms of volume, granularity, types or subsets of data) and what can be made available in the future with some investment – how much investment would be required for what outcome, etc. Please see our earlier comments in this regard.

We would also encourage the Authority to consider a data standard for the provision of PQD. The Australian data standard (referenced earlier) is an example we could consider adopting or aligning with.

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

Vector does not believe the transaction costs are too high, although our experience was that it took some time to negotiate access agreements with MEPs. This was because the larger MEPs had differing contracting models that they were comfortable with (with at least two contracts required for data in some cases).

We suggest that rather than diverting valuable resource to developing a default access agreement now (which may take some time), the Authority should instead recommend a single contracting model, i.e. direct agreements between MEPs and distributors/flexibility traders. This could be done alongside the proposed Code change to make the MEP the default provider of data. MEPs should also have to contract directly with flexibility traders and distributors for access agreements.

We do not believe a default access template is needed now. Vector has hopefully paved the way for these transaction costs to be lowered by negotiating extensively with MEPs, and those MEPs will now have a 'standard' agreement to offer to other industry parties. The hard work is done now, and we think the Authority's resources could be better utilised elsewhere.

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

***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?*

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?*

Vector agrees that MEP pricing for ICP data / consumption data appears to be reasonable, as required by the Code and Data Template.

We note though that there is a disparity in cost between direct provision of data by retailers vs provision of data via the MEPs. We expect that Code changes making MEPs the default providers of data will reduce this disparity in cost. The requirement for a direct contracting model between an MEP and the data recipient for access will help further lower transaction costs.

With respect to PQD, a better understanding of the different data sets available, volume of data available etc will help inform the issue of costs in relation to PQD. This in turn will depend on the availability of regulatory funding for trials to better understand the PQD landscape. The scale of the investment required to produce sufficient PQD volume and granularity are important determinants of cost.

In relation to consumption data, the Code requires pricing to be 'reasonable' and in our view, this keeps a check on MEPs' pricing. In relation to PQD pricing it is too early to comment as this data is not flowing yet. We think the Authority should give time for commercial solutions to develop. Certainly, in time, we would appreciate greater transparency for PQD prices.

As the Authority is aware, Vector has now contracted with MEPs for the delivery of virtually 100% of the ICP data on its network. We feel pricing has been standard and transparent. As such, we do not feel the IPAG recommendation needs to be implemented at this stage, as we do not consider pricing transparency has been an issue. There is also a risk that publication and full transparency of standard pricing increases risks of collusion.

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

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

Vector agrees that distributors' visibility of DER location, size, and functionality should be improved, but we believe this needs to occur on a much **faster** timescale than 3-7 years. Digitalisation, which has provided all of us with the world's information at our fingertips, means that customers are expecting our service agents, field crews and engineers to know the details about their connections to the network today, not in 3-7 years.

Distributors will need time before learnings from DER information can be confidently used to change network planning practices. The sooner we get access to this information, the sooner we can work out the challenges with data integration, analysing that information, and learning how our network responds to DERs.

Network planning is an ongoing process and without enough data to know if DERs are clustering at a local level the network planners will need to make assumptions when assessing specific network upgrades. Those assumptions today are based on the limited regional or national level information about DERs, but increasingly will need to be based on localised information.

In 3-7 years, information on DERs will bring additional value to network operations. We expect our network operations team to start utilising DER to support system and network emergencies in that timeframe (contingent on access to operational and real-time data for the LV network, and the ability to orchestrate outcomes). Information about DER will be important in ongoing assessments of network operations and will be able to monitor if DER are or are not enrolled in providing emergency services to the network.

If we start now, we have time to get this right before DER penetration, especially EVs, takes off. We currently only have visibility into solar PV and some battery installations, because of Part 6 and the associated safety implications, however, the existing process for that data could be improved upon. We would like more information on the following types of DER where shifting energy consumption by that DER has minimal consumer impact:

1. EVs – rapid uptake is predicted with significant potential impact on the LV network.
2. HVAC / refrigeration – thermal “batteries” often have existing control systems.
3. Smart hot water – updating existing HWLC with new meters or third-party solutions is needed.
4. Solar / other generation / batteries – the existing method / registry could be improved upon.

In our view, the first priority should be modifying or extending the ICP registry to include the size and type(s) of DER found at each ICP. We should ensure that this is designed so that it can easily be updated, ensuring the information is accurate at all times, and can accommodate multiple DERs at each ICP. A relatively simple way to allow multiple entries for each ICP would be with a linked table or registry for DER.

The next priority – in terms of information about each DER at an ICP – would be capturing the basic functionalities such as “Able to inject onto network” (T/F), “Able to shed load” (T/F), “Enrolled with DER Manager” (T/F) & “Contact for DER Manager” (i.e. Mercury, Evnex).

Additional detailed information like “Inverter Standard Used” (e.g. 4777.2:2015 or 4777.2:2020) or “Communications Protocol” (e.g. IEEE2030.5 or OpenADR 2.0b) may have value. However, the focus should be on getting simple, accurate information about DER penetration into the hands of network planning teams as soon as possible and debates about this information could slow down that process.

Applying metering and information provision requirements irrespective of whether a DER injects energy into network or whether the energy is consumed behind the ICP meter, as suggested in footnote 89 of the issues paper, may provide an incentive for maintaining the accuracy of the information in the ICP / DER registry. We welcome discussions with stakeholders to help establish the types of data and processes to ensure this information is updated and accurate.

Because we see value in information about and visibility of DERs, we have taken the following steps to improve our access in the absence of a DER Registry:

1. We are working directly with Waka Kotahi to get EV registration data. To protect consumer privacy the process requires significant effort by Waka Kotahi to manually match registration addresses and allocate aggregated anonymised counts of EVs to our network assets.
    a. We would appreciate the EA's advocacy and support for distributors to have access to EV registration data for the purposes of delivering electricity distribution services more efficiently. This support would validate Waka Kotahi’s collaboration so far and could lead to an automation of the process, thereby creating a new data source for all EDBs to gain insights into where EVs may be charging on our networks.
    b. Vector currently supplies Waka Kotahi with a service area for each distribution transformer for a subset of our network to minimise the burden on Waka Kotahi staff. Waka Kotahi then uses their EV registration information to provide counts of EVs for each distribution transformer. As the network is constantly evolving, the service area for distribution transformers is always changing, therefore an automated process is needed.

2. Our network connection standards[6] have been updated to include new details around electric vehicles:
    a. We seek "registration" of new EV charger installations by asking consumers or their installers to send Vector a copy of the Certificate of Compliance
        i. We would appreciate the EA's support of this practice as we begin communicating this to retailers and to EV charging equipment installers.
    b. Vehicle to Grid (V2G) chargers are clearly classified as distributed generation, which means consumers must follow the application processes for distributed generation.

3. Vector is creating a new residential tariff in 2023 for residential consumers who have DER capable of connecting or responding to Vector's DER Management System (DERMS). The DER price category is designed to provide the flexibility to manage load in the future such as electrical vehicles (EVs), batteries and smart appliances.
    a. Vector is developing an accompanying DERMS connection standard which specifies the international standard protocols of OpenADR, IEEE 2030.5 and OSCP as default options for enabling customer connections to the Vector DERMS. Vector will remain open to develop customised connections (outside of the supported standards) and is flexible to investigate and incorporate the use of new emerging protocols. This DERMS connection standard was developed with extensive expert research and interviews and is currently going through its final review before being published to Vector's website in the coming months.

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

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

Vector prefers to use the term 'near-real time' with respect to data. We split our ideal data requirements, and the timeliness with which we require data, as follows:

1. <u>Whole of network consumption data and power quality data.</u> This would be passively delivered to Vector based on contractual arrangements with MEPs. We would want this to be delivered:

    a. In an ideal future state (within 10 years) – within 15 minutes of the reading interval
    b. In the interim – an acceptable interim state for this data would be a 4 or 6 hourly interval following meter reading. Ideally, this interim state would be achieved within the next 2 to 3 years.

    Today, we are receiving monthly consumption data, and (a small subset of) trial PQD weekly.

2. <u>On-demand (meter ping data)</u> – This is proactively requested by Vector from MEPs for a limited set of ICPs (usually following an event). We would want this to be delivered:

    a. Within the next 2 years – an acceptable interim state would be in less than 5 minutes of the request; and
    b. Within the next 5 years – less than 60 seconds after an electronic request (meter ping) is sent.

As indicated above, Vector disagrees that access to real-time consumption data and PQD would not be needed for at least five years. We consider some 'near real-time' data is needed within the next 2 to 3 years and as the recent emergency events have shown, perhaps even more urgently than that.

[6] Available online at: https://www.vector.co.nz/kentico_content/assets/0dc3a5fa-e08d-4650-990b-bd806ce626b3/ESA002_Electricity_Network_Connection_Standard.pdf

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?*

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.*

Yes, we agree that flexibility traders should eventually have the same level of access to ICP data as distributors and retailers. However, see our earlier comments in this regard about the usefulness of that data and the need for it to be filtered and manipulated by EDBs first. At present, when flexibility traders are only just entering the market, there is time to ensure that key issues are properly addressed before that access is given. It is imperative that the right settings are in place first to protect customer data and consumer interests.

We consider neither option in relation to flexibility traders (modifying the Data Template or amending the Code) to be an immediate priority. Important considerations such as data security requirements or the range of obligations on flexibility traders ('aggregators' under the Code) in relation to data and permitted purposes must first be defined. Once that is considered and consulted on, then the mechanism to provide flexibility traders will naturally follow – an easier approach. The terms of access, which we consider to be of immediate priority, must first be carefully considered.

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?*

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

Vector agrees that flexibility traders (suppliers) will likely gain value in having access to congestion data on distribution networks. They could use that information to forecast their potential opportunities and revenues from flexibility supply (whether that is to distributors, other areas of the market, or to other markets).

1. Part 6 of the Code already requires distributors to publish a congestion management policy which publicly discloses network locations that are currently subject to export congestion. This includes listing locations that are expected to become subject to export congestion within the next 12 months.

2. The value of "granular congestion data" only comes when distribution networks themselves have access to data, the tools and the resources to create useful insights about future network requirements.

3. We do not see any disincentive to sharing congestion data with flexibility suppliers. We welcome flexibility suppliers offering services that can resolve congestion on our network while maintaining consumer affordability.

We have not had access to granular consumption data and matching historical consumption data for long enough to successfully 'ingest' it, 'clean' it, and then analyse it so it can be incorporated into our congestion and load forecasts. In addition, we need sufficient volumes of PQD to improve our understanding of ICP connectivity and phase mapping, and an ongoing supply of PQD will then allow us to more accurately forecast LV DER hosting capacity. It is therefore worth noting:

1. Distributors have only recently received access to granular consumption data and matching this to historical consumption data is necessary to build more robust forecasts.

2. There is a need to manage the expectations of flexibility traders regarding the accuracy and usefulness of forecasts. We acknowledge the challenges of generating highly accurate load forecasts.

3. We would prefer to provide granular-level forecasts after we have had sufficient time to incorporate the ICP-level data into our models. These models would calibrate our forecasts to ensure that information provided to flexibility traders has minimal risk of creating false expectations for network service opportunities.

***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?*

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

***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?*

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

As indicated in our responses to Questions 15 – 16, visibility on the location, size, and functionality of DER should be improved, far sooner than 3 – 7 years. The proposed reasoning in the question is somewhat accurate, but has the following limitations:

1. Drivers of network congestion – this information would be a valuable addition to the information that we currently utilise in our network planning for the purpose of forecasting and resolving network congestion issues. However, it is unlikely that DER information on its own could be used to determine the drivers of network congestion, as there are several factors affecting network congestion, in addition to DER.[7]

2. Determining what DER is 'manageable' – this type of registry would help identify the general aggregate availability of controllable DER in a region, and you could gather populate statistics about the share of certain types of DER that are able to be managed. It is likely that most equipment of the same type will have the same "functionality" entered into the registry. However, the registry does not provide information about whether the DER is enrolled with a DER Manager(s) to provide that flexibility to one or more portions of the electricity sector (one of which would be distribution businesses).

3. What services could be offered to owners of DER – the types of services offered to owners of DER will be dependent on the specific value that the buyer of that service gains. Being able to identify the specific need, and quantify the value of mitigating that need, will be the driver of the types of services offered to DER owners.

4. We do not think we will be able to forecast all the data needs and use cases for flexibility traders today. Therefore, our suggested priority would be getting the location (ICP), size, and

[7] Vector Limited Electricity Asset Management Plan 2021-2031. Sections 10.6.2 *Demand Forecasting* and 10.6.3 *Constraints and Options* (Pages 89- 91). Available online at: https://blob-static.vector.co.nz/blob/vector/media/vector2021/vec224-amp-2021-3031_310321.pdf

type(s) of DER related to each ICP as this has clear value to existing participants, including distributors, as noted in our response to Q15 and Q16.

5. In response to **Q24** and **Q25**, making minor modifications or extensions to the existing ICP registry is a sensible solution that requires adding managed access rights for flexibility traders. As parties across the sector begin using distributed energy, additional modifications can be prioritised as use cases begin to emerge, whether that is for flexibility traders, distributors, Transpower, or retailers.

6. The next priority in terms of information about each DER would be the basic functionality such as "Able to inject onto network" (T/F), "Able to shed load" (T/F), "Enrolled with DER Manager" (T/F) & "Contact for DER Manager" (e.g. Mercury, solarZero, Evnex). More detailed data about functionality will likely need to wait until flexibility services are more standardised in New Zealand.

7. It is likely that flexibility traders would use the information found in a DER registry to determine how and where to market to consumers to increase the amount of flexibility they have to offer. The Authority has already identified this as a risk and has suggested limitations in the use of this information by flexibility traders. But we believe that reducing the cost of customer acquisition and contracting is important to support the early growth of flexibility markets.

Proposed pathways to enable network visibility of EV chargers

Vector's submission on the *EECA green paper – improving the performance of EV chargers*, issued in August 2022, proposes two pathways that would provide distributors greater visibility of the EV chargers on their network. This would help them manage their network more efficiently, avoiding costly new network investment or expansion.

EV locational data requirements

The Certificate of Compliance pathway

Part 6 of the Code (*Connection of distributed generation*) requires the 'distributed generator' to register the 'distributed generation' (e.g. a solar system or vehicle-to-grid/V2G) with a distributor when it is installed:

9B Application for distributed generation of 10 kW or less in total in specified circumstances
(3) The distributed generator must also give the distributor the following information as soon as it is available, but no later than 10 business days after the approval of the application:

(a) a copy of the Certificate of Compliance issued under the Electricity (Safety) Regulations 2010 that relates to the distributed generation:
(b) the ICP identifier of the ICP at which the distributed generation is connected or is proposed to be connected, if one exists.

This registration is executed through a Certificate of Compliance being completed by the electrician and provided to the distributor. Whilst Part 6 applies to distributed generation (including V2G technology – which is captured by Part 6 as it injects power into the network, making it 'distributed generation'), this process could be expanded to include the registration of all EV charging installations. Indeed, including EV charging installations in the existing registry administered by the Authority is something Vector has been seeking for some time. Enabling network visibility of EV chargers through their associated ICP would cost virtually nothing. This option does not propose that the application process in its entirety, as set out in Part 6, be applied to all EV charging installations – only the requirement in section 9B(3).

There are also some important changes that would need to be introduced to ensure the viability of the provision of locational data of EV chargers to distributors:

1. The requirement to register the installation should be placed on the installer rather than the consumer. The Code currently imposes an obligation on a consumer (understood as a distributed generator for the purposes of Part 6 and thus an industry participant for the purposes of the Act) to provide the location of the installation. However, this is generally performed in practice by an electrician or installer. When data on the EV charger is not provided (as is true for around 14% of installations), following up with the installer rather than the consumer is more fruitful.

   We recommend that the Code reflect that the obligation to register the installation with the distributor rests with the installer. Having this clarity would increase consistency across retailer practices. Introducing this responsibility for installers now would be timely, alongside the introduction of an EV charger standard for chargers sold and installed in New Zealand.

2. Penalties for non-compliance should be introduced. Currently, the only recourse available to a distributor when there is non-compliance with the Code registration requirement is cutting the asset off the network. This is not a consumer-centric approach, and we virtually never do this. This also penalises a consumer when, in our view, the responsibility should rest with the installer.

   Requiring installers to register the installation gives rise to the need for a viable penalty on installers for non-compliance, i.e. to enforce the registration requirements. The burden of registering an installation to provide evidence for compliance is much less than the burden on a distributor following up 14% of installations to gain the registration data. This burden on distributors would only increase if the registration requirements were broadened without the appropriate enforcement levers.

3. The Authority's registry needs to be amended so that registered assets can be 'tagged' as an EV. This currently does not exist, even for V2G – for which the registration requirement already exists. As a result, these assets are 'seen' as being similar to distributed generation – even though their power injection behaviour is likely to have some differences which are relevant for network management purposes. For the process of providing networks with data on the location of EVs to be viable, new categories for 'V2G' and 'EV charger' would need to be added in the registry so that the type of asset is identified upon registration.

We appreciate that Part 6 is designed to apply to distributed generation – and indeed that the Code can only apply to those who are an "industry participant" as defined in the *Electricity Industry Act 2010*. While amending the Code is the role of the Authority, rather than EECA's, we understand that the relevant Crown entities will be working together to determine the best means by which to achieve desired EV-related outcomes.

Qualified installer programme pathway

The UK's Office of Zero Emissions Vehicles (OZEV) administers a scheme through which people can become a registered installer for EV charge points (CPs). This is alongside regulations that ensure the CPs sold and installed have smart functionality, and a subsidy for compliant EV CPs which is claimed back by installers for customers.

To become accredited, installers must:

- be registered with a Competent Persons Scheme (which is also a requirement to become a registered electrician);

- have completed an EV charging course (these typically have pass rates of 100% and cost around £350); and

- have completed the course of a manufacturer and registered with them to install their EV CPs.

Depending on the manufacturer and home requirements, a home installation takes around two hours. The EV CP typically costs between £300 - £1000. Depending on the manufacturer, installers connect a smart CP with a platform for management as part of the installation process. There are separate qualification channels outside of the OZEV registered installer scheme through which someone can install an EV charger, although these pathways are not eligible for the EV subsidy.

For the full value of smart EV charging to be realised, chargers need to both have the right functionality and be connected to a platform or third-party aggregator for management. Whilst there is a need to ensure that the devices carry the right 'smartness', there is also a need to subsequently consider pathways beyond a regulated standard to drive connectivity. A qualified installer programme (or process – which leverages existing electrician qualifications in New Zealand) or a widened Certificate of Compliance process could provide this. As is the case in the UK, the installation process could ensure that the EV charger is connected to a demand management platform at the time of installation. Unlike the provision of EV registration data by ICP, this outcome does not need to be delivered now, but will need to be soon.

In our view, there is also the real need to ensure that regulations are accompanied by the right incentives, processes, and market solutions – to avoid a situation where every EV charger is smart but continues to behave in a non-smart way.

Facilitating EV registration

The ability of an EV charger to capture and transmit data on its location may be a valuable way of future proofing pathways for EV chargers to add the most value to the electricity system in the future, i.e. this data may be valuable for planners or local government. For networks, the key thing is that the EV is registered against an ICP.

Rather than require EVs to collect and transmit location data, we recommend:

- that the existing Certificate of Compliance process is improved and widened, as above, to ensure that EV registration data – which is imperative for network planning – is immediately provided to distributors with some degree of certainty; and

- the exploration of a qualified installer programme as an option, noting that such a pathway may also be valuable in enrolling EVs into valuable demand management services in the future.

These two steps could be considered together with the development of a pathway for EV registration and connection. This supports our recommendation that registration requirements rest with the installer rather than the end consumer.

Currently, there are no smart product requirements for EV chargers in New Zealand. Sales of EVs and aftermarket EV chargers are increasing, impacting overall electricity demand. Some distributors are managing local EV-related events, e.g. where there are high concentrations of EVs on a street. To date, the market response is largely limited to EV tariffs, offered by some retailers and designed to encourage charging outside of peak hours.

Internationally, there is strong interest in regulating the performance of EV chargers, in recognition of their importance to flexible electricity systems. **Vector strongly supports mandated smart charging standards for EV chargers, including, as discussed later in this submission, off-peak charging by default and a randomised, delayed return.**

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

Vector agrees that making provisions for real-time congestion data and real-time ICP data from smart meters is not needed for flexibility suppliers within the next five years. Appropriate real-time congestion information for flexibility suppliers will likely be provided by distributors after they have obtained relevant real-time data and have the platforms and systems in place to utilise it for network operations.

It is anticipated that distributors may request flexibility traders (suppliers) modify the behaviour of groups of ICPs' DER to support system or network emergencies in near real-time, which is a type of real-time congestion data. At present, as discussed later in this submission, this could be enabled through the load management protocol, contemplated by the Default Distributor Agreement (DDA), with any retailers that are flexibility suppliers by virtue of managing consumer loads. However, the load management protocol does not extend to other flexibility suppliers at this time.

The response to the question about the delivery of ongoing real-time data to flexibility suppliers may not be useful without putting it in the context of network operations by distributors.

Real-time operational data available to distributors is currently limited to larger assets, where it has been both cost-effective and critical to install the monitoring equipment that provides improved network reliability.

As discussed above, Vector is beginning work with the two major MEPs in New Zealand to understand what the barriers are to getting real-time operational data at an ICP level through the existing metering fleet. Given the 'end of life' of the first generation of the metering fleet is in sight, these conversations are timely to ensure that the types of replacement smart meters will include appropriate communications, internal metering, and configurability to make real-time data easier to access and manage.

***Q28**. Do you agree that model privacy disclosure terms are appropriate? If not, why not?*

***Q29**. Do you agree that model privacy disclosure terms would facilitate data access? If not, why not?*

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

***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?*

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

Vector does not consider model privacy disclosure terms are needed as this is sufficiently consistent and broad across retailer terms presently, due in large part we suspect to the Authority's *Final Principles and Minimum Terms and Conditions for Domestic Contracts for Delivered*

Electricity.[8]

However, should the Authority consider it necessary to produce model privacy disclosure terms, we would support a broad purposive approach in line with the Privacy Act rather than more prescriptive or restrictive terms as contained within specific contractual agreements, such as the Data Template.

Vector cannot see any practical issues with the above proposals.

We do not see the need for model privacy terms for distributors and MEPs at all, on the basis that neither party has direct contracts with end consumers. Both parties contract with retailers whose obligations are to the end consumer. For this reason, model privacy terms for inclusion in retailer contracts may be needed, but not for distributors and MEPs.

We do not consider the Authority conducting privacy preserving/minimisation techniques to be necessary; the Authority's resources can be better utilised elsewhere. Privacy obligations are well understood by the industry in general, although potentially smaller and new-entrant flexibility traders may (in time) benefit from workshops on data privacy.

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8 Available online at https://www.ea.govt.nz/assets/dms-assets/17/17876Principles-and-minimum-terms-and-conditions-for-domestic-contracts-for-delivered-electricity-Interp.PDF

Market settings for equal access

Vector's Symphony strategy has the efficient use of NWAs at its heart

As set out in the first section of this submission, Vector's Symphony strategy is explicitly focussed on the application of mass deployment of non-wire alternatives (NWAs) to avoid building traditional poles and wires. Vector therefore has no intention of building traditional investments, and growing its regulated asset base, unless it is absolutely, and unavoidably, necessary.

This assumes, of course, that applying NWAs will come at a lower cost to consumers than the corresponding traditional investments avoided.

Over the past decade, Vector has trialled and deployed a range of NWAs across its network, including battery-electric storage systems at six locations, microgrids at Piha and South Head, smart hot-water management trials, a trial of a peak-time rebate for mass-market customers, and a managed EV charging trial with 200 EV owners. We also recently co-developed a managed charging solution with Auckland Transport at its new electric bus charging depot in Panmure. We would now be one of the parties most experienced in the provision of NWAs in New Zealand. We are not alone among distributors, however – further information on our trials, and those of other distributors, can be found in a recent summary prepared by IPAG[9].

Clearly, our experience of deploying NWAs has been gained largely through self-supply, although we have gone to market for technology solutions where appropriate. However, we recognise the broad policy direction and intent for us to go to market for "NWAs as a service", so having identified a suitable candidate investment project for a NWA we recently tested the market for such offerings. Our experience is set out below.

Vector's experience from the ROI for NWAs in Warkworth

The Auckland Unitary plan forecasts significant growth in the Warkworth region, north of Auckland. Access to the region will be significantly improved due to the soon-to-be-completed Puhoi to Warkworth motorway and the proposed Warkworth to Te Hana motorway. The changes to the urban boundary are expected to open significant new land for development, particularly for commercial and industrial development, including a potential new large customer. As a result, the number of customers is forecast to grow from 16,000 at present to 25,000 over the next 30 years.

The wider Warkworth region is supplied by two long 33 kV sub-transmission lines from Transpower's Wellsford grid exit point (GXP). Based on current load forecasts, if one line were to fail during a cold winter night (e.g. a contingency situation) then the other line would be overloaded by as soon as 2023. Vector's options were to upgrade the existing lines or construct a new line using underground cables in ducts being installed as part of the new motorway construction. We were seeking a reliable and cost-effective NWA to manage the loading on the sub-transmission lines. Additionally, we identified the NWA could also be used to defer upgrades of the Warkworth zone substation (ZSS) (expected around 2028) and the Snells Beach ZSS (expected around 2026). This suggested a long-term opportunity (about 10 years) for providers of NWAs in the wider Warkworth region commencing in Winter 2023.

The potential need for load management in the Warkworth region was identified in the 2018 AMP, though the original projected dates for the emergence of this need were not accurate due to significant uncertainty around the timing and scale of growth in the region, which is a common challenge for network planning.

In January 2022, Vector sought Registrations of Interest (ROI) from suitably qualified

[9] Available online at https://www.ea.govt.nz/assets/dms-assets/27/04-Summary-of-EDB-responses.pdf

suppliers who were interested in delivering non-wires alternatives (NWAs) in the wider Warkworth region. The ROI was intended to start engagement with potential suppliers and invite them to register their interest in participating in any future Request for Proposals (RFP). We determined a need for a total of 3-5 MW to alleviate the network constraint for periods of 2-5 years and were seeking to purchase this in 1 MW blocks. We were open to working with multiple suppliers subject to each supplier being able to provide a minimum quantity of support

We received 24 applications in response to our ROI. Of those 24 applications, twelve had not been fully completed. Of the remaining twelve completed applications, there were none that would utilise existing DER in the Warkworth region – all required investment in new DER, in some shape or form. Upon further consideration of the twelve completed applications, six applications were selected for in-depth discussions to further understand their offerings. Following these in-depth discussions, one application was taken further and considered further for deployment.

Many of the applications Vector received relied on access to land to successfully deploy their solution. Given that Vector only has land rights at the substation, there was no guarantee that other consumers would consent to having equipment installed on their land. Additionally, many of the solutions offered to construct for Vector new, permanent physical installations (that Vector would own and operate, long-term) as opposed to offering a short-term "as-a-service" contract that Vector could procure for the time periods that supported the investment deferrals.

One of the challenges to the contracting model is that once the infrastructure investment is necessary and has been completed, there will be significantly reduced value for load deferment in the region. Another challenge that suppliers faced was being able to connect to the network in an area that can deliver the benefits of the non-wires service. In some cases, providers were seeking to deploy a large-scale solution in an area with low existing network capacity, which would cause separate security of supply issues which Vector would need to mitigate prior to that supplier being able to provide value.

Our key learnings from this experience have been as follows:

1. NWAs absolutely offer viable alternatives for certain applications, but the economics are challenging – especially if a technology roll-out is required. Also, while DERs are often touted as swift to access, in our situation there was no existing or latent flexibility available in the area – all solutions required the deployment of new technology, some of which would have required significant levels of sales to mass-market consumers. This means NWA projects require considerate lead times to procure and deploy the equipment, and the roll-out likely needs to be underpinned by multiple revenue streams.

2. The flexibility service market needs building, as today most NWAs on offer are technology solutions, which require innovation funding from distributors. However, distributors have very little allowance for funding innovation if not directly linked to business outcomes, which makes it difficult for distributors to justify these investments under current regulations. New Zealand is lagging behind other countries in enabling an effective flexibility market. Public funding available to deploy flexibility solutions and grow the market in other countries (e.g., Australia, UK) far exceeds the innovation budgets available in New Zealand.

3. Regulated distributors need more funding for flexibility as the current fixed five-year regulatory periods offer little room to change course by swapping a capex solution for an opex solution. Further, distributors are still accountable for reliability (SAIDI, SAIFI) and bear the reputational risk of any non-performance issues causing outages on the network. However, solutions providers are expecting distributors to lead the development of the flexibility market. Alternatively, deployment and operation of solutions can be incentivised by cost-reflective distribution pricing (instead of dedicated OPEX funding), but, depending on the locational granularity of the constraint being managed, may not deliver the performance guarantees distributors will need to defer investment with confidence

Not all capital expenditure can be directly replaced by NWAs

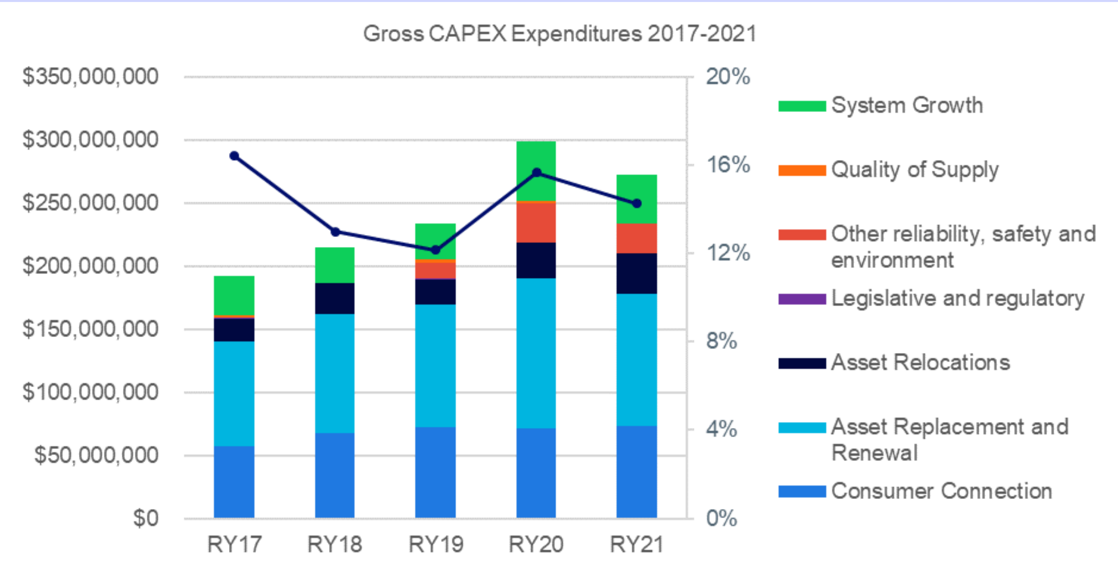
It is important for parties offering to provide flexibility services to distributors to realise that not all capital investments can be replaced by NWAs. As per our Symphony objective, the choice of whether to deploy traditional infrastructure or a NWA is a critical concern for us, and, as explained later in this section, assessment of suitability for NWAs is now a key part of our investment planning process.

However, to be suitable, investments need to meet certain criteria, and be of sufficient scale to justify the process and transaction costs required. Ultimately, as explained below, only a relatively small proportion of a distributor's overall capital expenditure eventually fits into this category.

The profile of Vector's capital expenditure and the applicability of NWAs

As part of the Symphony strategy, our planning process has incorporated the evaluation of non-wires alternatives for system growth projects. The Commerce Commission defines System growth projects as a class of projects within our CAPEX budget "*where the primary driver is a change in demand or generation on a part of the network which results in a requirement for either additional capacity to meet this demand or additional investment to maintain current security and/or quality of supply standards due to the increased demand*."[10]

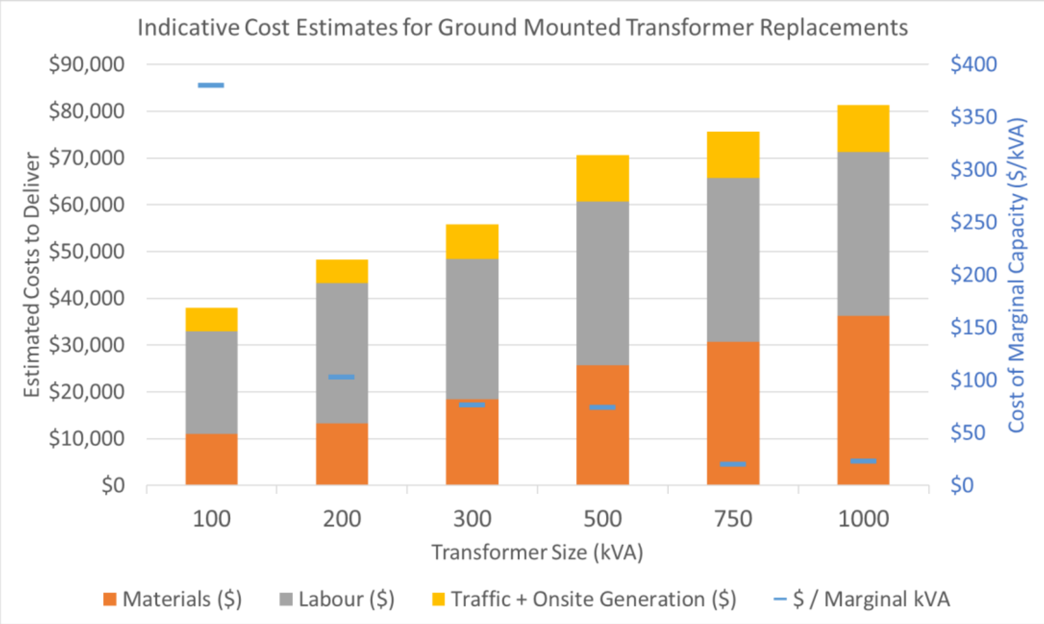
Vector's expenditure on System growth projects has averaged approximately $38M annually over the last three regulatory years, which is around 14% of Vector's gross CAPEX expenditures. As shown in the figure below, the largest shares of our CAPEX expenditures for that same time period have been for asset replacement (40%) and customer connections (27%):



Non-wires alternatives are not generally well-suited for asset replacement projects as the condition of an asset is what drives the need for a replacement, and it is unlikely that the use of non-network solutions will be able to fully replace the asset.

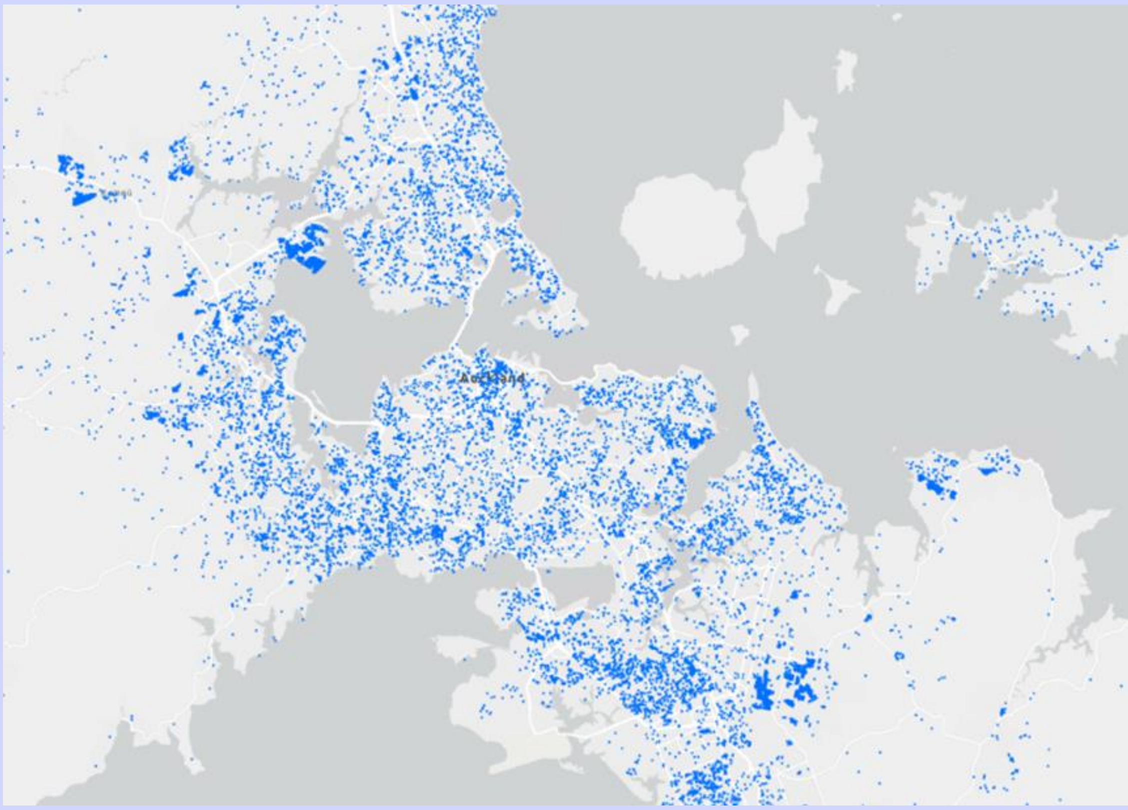
We have gathered costs for typical ground-mounted transformer replacement projects shown below. Of note, there are efficiencies to consider when a transformer replacement project is scheduled in an area where future growth is forecasted due to the decreasing costs of marginal capacity as transformers increase in size. A NWA would need to be competitive with the marginal cost of the next largest transformer on an annualised basis to merit consideration during a replacement project in an area where growth is forecasted.

[10] See https://comcom.govt.nz/__data/assets/pdf_file/0024/272931/Electricity-Distribution-Information-Disclosure-Determination-2012-Consolidated-version-9-December-2021.pdf



For customer connections, we have a focus on delivering seamless and great experiences for our customers as they engage with us. We received 5,835 connection requests in the 2021 regulatory year, an average of just under 16 new connection requests per day, and each new connection request can potentially consist of multiple new ICPs – as in the case of residential developments.

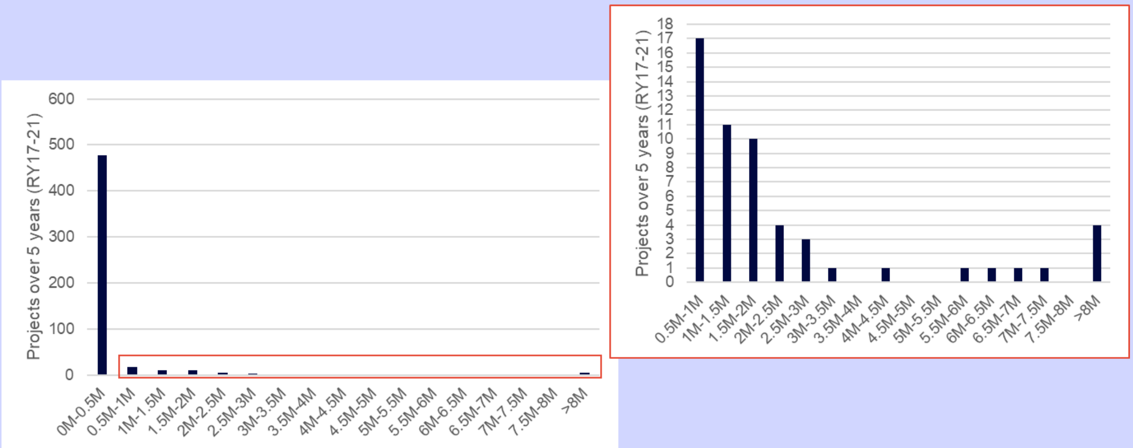
As shown in the figure below, these new connections occur all over our network, with limited concentration. We have limited foresight or indication of exactly when and where new connection requests will appear on the network, and customers' expected timeframes for enabling the new connections are short, making the deployment of non-network solutions for these investments quite challenging. Customers do, however, have the option to investigate and harness NWAs to manage the costs they incur for a new connection, particularly at scale – as occurred with the recent development of the e-bus charging depot in Panmure.



Locations of New "Standard" ICPs on Vector's network, 2018-2021 (~52,000 ICPs)

Vector is primarily an urban network, which means that a large share of our network infrastructure is <u>interconnected</u> and <u>shared</u> across many customers. For many system growth projects, we are therefore able to make efficient modifications to the network such as strengthening individual sections or adding additional interconnections between different network assets.

As can be seen in the figures below, over 85% of system growth projects from the past five years (by number) have been delivered for less than $500,000.



System Growth projects from FY2017 - FY2021 by cost

Over the past five regulatory years (FY2017-FY2021), 17 system growth projects exceeded $2M in costs. These projects mainly consisted of sub-transmission and zone substation projects, for which NWAs are considered as part of the planning process. In many cases the rate of growth, which has been high in Auckland over the last decade, and the unpredictability of that growth, makes a network solution the most economic choice. In other cases, NWAs were identified during the planning process, such as the Glen Innes battery storage system, which was the first of its kind in the Southern Hemisphere.

On the back of a number of trials, Vector has developed a deep knowledge base around the technical potential of NWAs and has subsequently included the use of NWAs to defer network reinforcement as one of the pillars of its Symphony strategy. Building upon the knowledge gained from these trials, Vector has developed a framework to understand the value of NWAs compared to wires solutions which fits into the network planning process. The model can capture the value of NWAs for networks by computing the deferment value of the wires/network solution. If the levels of service and risk are similar between the wires and the NWA, and the NWA deployment cost is lower than the value of NWAs, then NWA are the most economic solutions from a societal/customer perspective. Most importantly the model reflects future uncertainty and the optionality contribution of NWAs.

In the course of developing and publishing our upcoming Asset Management Plan (AMP) for the period of 2023-2033, Vector has developed a new method for screening economic suitability of non-wires alternatives based on network deferral savings as part of the investment planning process. This method, and the resulting candidate areas for non-wires alternatives, will be included in the AMP when it is published in April 2023.

While Vector's experience to date has largely been gleaned via a "hands-on" approach, going forward Vector does not have a preference for implementing solutions itself, or through a part of the Vector Group, as demonstrated by the ROI in 2022 for NWAs to serve the Warkworth area of the network[11]. Fundamentally, we are seeking the best long-term solution for our consumers, irrespective of the type of solution, or the provider.

Q31*[a]. 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?*

Networks must first build the tools and platforms that integrate data, thereby enabling better visibility at low-voltage networks, before the education and guidance suggested in Option 1 yields meaningful value.

With these platforms in place and more information about DER on the network taken care of first, networks will then be in a better position to share learnings amongst each other about the use and procurement of non-network services. As CEG notes in the expert report appended to this submission: "*Once EDBs have a platform for identifying where and when flexibility services will be of most value, the next question is how they can most efficiently procure these services*." [12] (see the call-out box titled "CEG expert report: Distributors self-supplying NWAs can be efficient" later in this submission.)

Several years ago, Vector dedicated time and resources to begin building these data platforms even though we had limited access to historical smart meter data. We will continue to improve upon these initial platforms as we now expect ongoing access to consumption data and are beginning trials with operational data from smart meters. The insights gained from our initial efforts have been used to shift our planning approach to now start with consumers.

Vector's planning approach is designed to meet our security of supply standards, quality of service, and power quality requirements for consumers. It starts with developing a customer model that assesses the demands placed on the network from the consumer-level. We can then build our

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[11] Available online at: https://www.vector.co.nz/news/registrations-of-interest-(roi)-warkworth

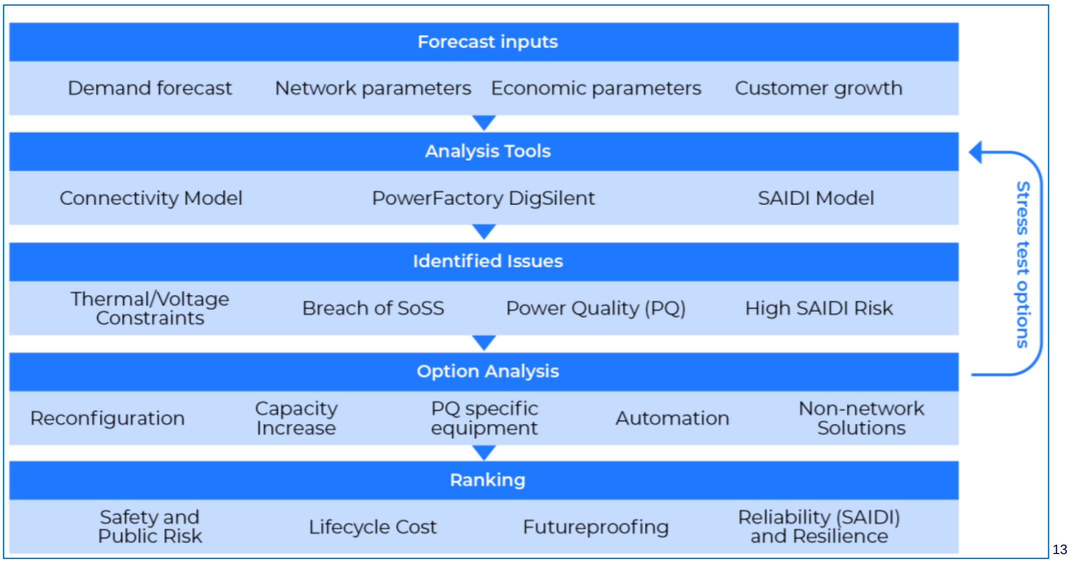
[12] Available online at: https://blob-static.vector.co.nz/blob/vector/media/vector-2022/vector-and-ceg-attachment-1-to-cross-submission-on-im-review-process-26-issues-paper-and-draft-framework-paper-3-august-2022-cleaned.pdf

understanding of future network requirements from the bottom-up, while accounting for locational differences and informing options analysis. With appropriate access to data (both from smart meters and on DER locations), new consumer behaviour and technology adoption can also be observed, integrated into the model, and considered in its early stages. This allows for more foresight and preparedness in the planning process, as well as enabling more active consumer engagement.

The planning process is initiated by an annual assessment of the peak loading on all distribution feeders and zone substations. This reassesses the summer and winter loading and security levels with updated information. The distribution network loading and security assessment includes thermal limits and voltage modelling, which is used to identify any potential issues on the network. We then review the options for resolving those issues.

Once the type, location and timing of a constraint is identified, options analysis is undertaken to identify and evaluate the best solution. Our options analysis considers not only wire solutions (e.g. cables, lines, transformers), but also innovative NWAs (e.g. smart hot-water control, batteries, smart EV charging), in line with our strategy to only build new infrastructure when there are not more affordable solutions available. We use a number of analytical tools and visualizations to assist with identifying the demand, network constraints and benefits of different options. If more detailed analysis on network constraint or technical assessment of the options is required, we will run specific power flow simulations as required.

To identify the best solutions and optimise and prioritise the network investment, Vector takes a whole-of-life-cycle approach to options evaluation. All the options identified are assessed and ranked based on benefits to network safety, life-cycle cost and impact on customer affordability (initial investment plus ongoing operational costs), reduction to network risk, ability to meet performance requirements and climate resilience (e.g., risk exposure). This process is shown graphically below.



[13]

Our future planning scenarios contain significant uncertainties due to the pace of technology development, changes in consumer preferences, and new government interventions to promote electrification; and NWAs offer benefits that assist with planning for these uncertainties: they are less intrusive in road corridors, and heavy engineering works are reduced (i.e. a smaller community impact and more agile to deploy); and they are also more modular (i.e. can start at a small scale and grow incrementally to fit the need) reducing the risk of stranded assets by dynamically matching

[13] Vector Limited Electricity Asset Management Plan 2021-2031. Figure 10-3 (Page 91). Available online at: https://blob-static.vector.co.nz/blob/vector/media/vector2021/vec224-amp-2021-3031_310321.pdf

needs as they evolve over time.

Wired options and NWAs are, however, not directly comparable based on their upfront cost alone, as they have different characteristics and do not provide the same network reinforcement ‘service’. In particular:

1. Wires (or network) solutions involve reinforcement of the network due to load growth. They eliminate a network constraint for generally 15+ years, have a lifetime of more than 40+ years and are a lumpy ‘no-return’/irreversible investment decision.

2. NWAs have very different characteristics:

    i. depending on the load growth, they may only *defer* the need for the wires alternative, but not eliminate it, and the period of deferment may end up being much shorter than predicted or originally contracted (and paid) for, if a large new load emerges (e.g. data centre);
    ii. the technology has shorter lifetime (certainly less than 20 years, but often less than 10 years);
    iii. they introduce new uptake and performance risks due to technology adoption and customer behaviour, and
    iv. the decentralised nature of the NWA solution means that it is adaptable/modular/scalable so that it can be adapted as load changes over time.

We have developed a framework to evaluate NWAs with wires solutions, and to assess if an NWA is the appropriate and economic option. This framework builds on our trials and experiences and applies learnings from international research and practices. The purpose of this framework is to ensure that when an NWA is pursued that the full lifecycle costs (deployment and operation) are lower than undertaking a wires or network investment for that equivalent period. We acknowledge that the cost to the distributor of purchasing an NWA “as a service” from a third party will depend on a number of different factors, including what other revenue streams the third party can access (i.e. how much value they can “stack"), whilst still delivering the contracted service. Therefore, the cost of the NWA service provided by a third party could be significantly less than if the same NWA had been developed for only a single application. This highlights the importance of going out to market for such solutions.

Our regulatory framework and good industry practice mean networks will ultimately pursue the solutions that effectively resolve constraints in the most economical way for consumers, however greater flexibility between opex and capex allowances under the current regulatory structure would simplify the pursuit of NWAs. This is an issue that has been raised by the ComCom in the input methodologies review currently underway. We are committed to working with the ComCom to find an appropriate solution that helps distributors manage the uncertainty that affects our investment plans within DPP periods. The key is ensuring that distributors can implement the most efficient solutions, and this requires that distributors can access and utilise the most up to date information to find those solutions. Therefore, we will also be working closely with the ComCom to ensure that we have adequate allowances in the upcoming DPP reset that enable us to pursue these non-network solutions.

This approach aligns with Option 2, because working together with the ComCom to create a supportive environment for learning-by-doing is critical to increasing the use of NWAs. Real-world learnings help drive confidence in performance across the sector, uncover contracting and operational barriers, and create opportunities for both distributors and flexibility suppliers to understand consumer’s expectations and responses.

***Q32**[a]. 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?*

***Q33**. Do you think there are circumstances in which the Authority should extend the Arm's-Length Rules? If not, why not?*

Issue 2: Distributors may favour in-house NNS

In response to **Q32**, we agree with options supported (both strongly and tentatively) by the Authority: monitoring the use of competitive procurement, and encouraging distributors to make standing offers to flexibility providers. Given the current nascency of the market, and the complexity of the contracts that are required, we encourage the Authority to help foster an environment that enables commercial solutions to emerge, through learning-by-doing, in preference to regulation.

In particular, Vector strongly supports the Authority utilising readily-available information provided in the distributor' information disclosures as a tool to monitor competitive procurement.

Distributors' "standing offers" for flexibility, are, at their heart, a question of distribution pricing. It may be hard to prescribe or standardise these offers too much, as the value of flexibility will differ markedly across time and across locations – something that the Authority's Pricing team is well aware of.

We have made significant progress in recent years with our new time of use (ToU) tariffs, procurement efforts for non-network services, and broader engagement with DER providers. Vector will be signposting specific areas of our network that we forecast as good candidates for NWAs in our Asset Management Plan and look to engage with DER providers to implement NWAs that provide improved value for our consumers.

As with the controlled load tariffs referenced by the Authority, ToU distribution tariffs are another example of an existing "standing offer" designed to encourage long-term alternatives to network investments. Vector currently offers customers a much lower price per kWh consumed outside our typical "peak" congestion periods, and in fact our tariffs for the coming year have priced off-peak consumption at 0c/kWh for standard users. Given that networks must have enough infrastructure to accommodate peak periods, this discount is a standing offer price encouraging consumers to shift their usage out of peak periods, with the desired outcome of suppressing growth in peak demand and avoiding future network investments. This encourages the use of flexibility behind the consumer's meter – whether by the consumer themselves, or their agent (which could be the retailer). It is simple for a prospective provider of flexibility to calculate the value they can earn for the consumer (in terms of avoided distribution charges) by shifting a kW of load from peak periods to off-peak periods through the year – in our case, up to approximately $100/kW/year.

We are continuing to apply the learnings from our trials and experiences from activities like the Warkworth ROI and the Auckland Transport e-bus depot to enhance our processes for evaluating non-network options. We understand that flexibility providers are interested in more accessible information about upcoming areas where they could provide services to Vector and, as mentioned above, we are adding a section in the AMP this year with specific network projects that we believe may be suited to NWAs. Our aim is to run the existing network smarter, and only invest in new infrastructure when we absolutely have to.

An option for increased transparency regarding non-network solutions might be sharing non-proprietary data from procurement processes, as described in the following example from the Rocky Mountain Institute's report *Non-Wires Solutions Implementation Playbook: A Practical Guide for Regulators, Utilities, and Developers* from 2018.[14]:

> A utility's release of non-proprietary data or lessons learned following a procurement process can also provide useful market information. Earlier this year, Xcel Energy ran a competitive all-source solicitation process for generation and released to the public anonymized data regarding the cost and number of bidders for each type of

[14] Prince, Jason, Jeff Waller, Lauren Shwisberg, and Mark Dyson. *The Non-Wires Solutions Implementation Playbook: A Practical Guide for Regulators, Utilities, and Developers*. Rocky Mountain Institute, 2018. Available online at: http://www.rmi.org/insight/non-wires-solutionsplaybook/

technology. This information, specifically the strikingly low cost of renewable resources, generated significant interest and shifted many stakeholder perceptions regarding the cost of these resources. Similar data regarding cost and efficacy of NWS can support the evolving understanding of their value and broaden the marketplace for non-wires solution services.

In some ways it is straightforward to have standardised disclosures for the procurement of new generation as was described in this example, because the markets and service are mature and well defined. We have not reached that level of maturity with flexibility in New Zealand, so perhaps the best initial approach is to share results with the Authority. In 2022, Vector arranged two sessions to share our learnings with the Authority as we worked through the submissions and the outcomes from our procurement for non-network services for the Warkworth region, and we plan to continue doing so for any future procurement of NWAs. At this stage of market maturity, we believe this level of information sharing with our regulators should be expected and is sufficient to track the development of flexibility services and networks' pursuit of NWAs in New Zealand. We also shared our learnings in a presentation to the ENA Smart Technology Working Group in 2022. We would expect other distributors undertaking procurement of NWAs to do the same, and the Authority's Market Monitoring team could use this information to produce an annual report of market evolution.

In response to **Q33**, before answer the question it is worth the Authority re-examining the potential problem of distributors' self-suppling flexibility services, and the potential harm.

Last August, in response to similar concerns raised by submitters to the Commerce Commission's (ComCom) Input Methodologies (IMs) review process, we commissioned expert economists CEG to answer the question of whether self-supply was in fact a problem needing to be addressed. As discussed in the box below, their response was an emphatic "no".

CEG report: Distributors self-supplying NWAs can be efficient

The Authority's Issues Paper, and many in the industry, appear to start with the presumption that it will be more efficient, and in the long-term interests of consumers, for flexibility services to be provided by any party other than the distributor.

In August 2022, Vector commissioned CEG to address this presumption and summarise the economic literature relating to self-supply. This paper was submitted to the Commerce Commission as part of their IMs review, and is also appended to this submission.

In their paper, CEG introduce the topic of flexibility services, and the ability of a future DSO to unlock benefits across the supply chain by harnessing these services. CEG highlight the "virtuous circle" of benefits unlocked by the combination of inflexible renewable generation and flexible DER:

- an increasing penetration of renewable generation lowers energy prices, but increases price-based volatility. Due to a concept referred to as the "merit order effect", each new renewable generator cannibalises the earnings of all other, correlated generators (e.g. a new wind farm's generation will be correlated, at least to some extent, with the generation levels of all existing wind generators. The same is true for new solar generation)
- this increases the value of flexibility to the system, and the incentive for more investment and operation of enabling technology. Increased flexibility will reduce price volatility, smoothing price differences between windy/sunny and still/overcast periods, and boosting the earnings of existing and potential generators
- the increased flexibility of the system, and smoother prices, increases the incentive for renewable generators to invest, and so on

While many of these benefits could still be realised without an active DSO, the more of these resources are connected to distribution networks, the more active orchestration and dynamic allocation of network capacity will be required to enable the full potential of these DER. This certainly cannot happen without an active DSO. The alternative is for DER to be relatively tightly constrained, using static operating envelopes, limiting the ability of DER Managers to value stack.

As noted above, and in CEG's report (section 3.1), there is a prevailing view in the sector that distributors should be required to purchase flexibility services at arm's length. CEG replies that:

To the extent that retailers can and do sell flexibility to EDBs at a lower cost than the EDB procuring flexibility directly from its customers then the regulatory regime can and should be incentivising EDBs to buy that flexibility at the lowest cost. However, it would be a grave error if EDBs were forced to buy all flexibility services at arm's length before there is any evidence that this results in the lowest costs to consumers. Indeed, it would be an especially grave error when there is reason to believe … that purchasing flexibility services at arm's length will, at least in some circumstances, be higher cost than self-supply.

CEG support this with the following points:

As is well understood in the economic literature, if "contestable" provision by "open competitive processes" was always the most efficient way to coordinate economic activity then there would be no "firms". The very existence of firms tells us that self-supply is often more efficient than supply via arm's length markets. …

EDBs should be given an incentive to choose external supply whenever it is lower cost than self-supply – just as EDBs are currently incentivised to do so in other areas of their operation (e.g., IT services, vegetation management, field services and maintenance and some construction services).

Using the example of a grid-scale battery-energy storage system (BESS) providing network support services, CEG note that the distributor could self-supply the BESS services, or:

… the EDB could develop a contract for a third party to supply the BESS services and hold an arm's length tender for the right to fulfil that contract. That contract would need to attempt to specify all of the potential contingencies that might occur over the life of the contract and what is to be done by the relevant parties in the event of those contingencies.

The problem with the latter approach, as identified in the economic literature, is that any such contract is difficult to write. Inevitably the contract will be "incomplete" in that some contingencies, and the associated efficient actions in the event of those contingencies, are too difficult to specify in a legal contract (and many contingencies may not be able to be specified). …

Following further discussion of the practicalities and pros and cons of each approach, in summary, CEG conclude:

Put another way, just because it is possible that BESS services could be supplied in a contestable tender process does not mean that it is efficient for this to occur. Forcing EDBs to buy these services in a "competitive market" will often just not be economically sensible. There are similar reasons why it is not sensible that the EDB tender to third parties to build and own substations and the EDB contracting for the services from those substations. While it is possible to put many services out to tender, it is not always efficient to do so.

On the strength of the advice from CEG that the theory of the firm, incomplete contracts and transaction costs all suggest that, at least in some circumstances, self-supply can and will be in the best interests of consumers, we suggest that the Authority revisits its problem definition. Further, as we noted above, given the current nascency of the market, and the complexity of the contracts that are required, we encourage the Authority to help foster an environment that enables commercial solutions to emerge, through learning-by-doing, in preference to regulation.

In response to the question, we note the Commerce Commission's competition role (enforcement of sections 27 and 36 of the Commerce Act) already has responsibility to ensure that distributors do not favour in-house solutions. There is also an established regime for monitoring related-party transactions (RTP), established rules around cost allocation between regulated and unregulated activities, and distributors will all have robust procurement policies.

In the process of developing this work further, it would be worth the Authority highlighting to the ComCom any particular deficiencies in or concerns they have with the ComCom's RTP or cost allocation regimes, or indeed their wider monitoring of competitive behaviour, that may have the potential to limit competition in the provision of flexibility services.

In response to **Q33**, given the introduction of the new Part 6A of the Code, and the establishment of the Authority's new powers, we do, however, think there would be value in the Authority clarifying, and consulting on, whether and how it would consider using its new powers to extend the Arm's Length rules.

In our view, before making an intervention with an extension of the arm's length rules, the Authority would need to determine:

1. the nature and magnitude of the lessening in competition that would occur, absent intervention, which therefore must consider the existing role of the ComCom;

2. if an extension of the arm's length rules are a proportionate intervention that would address the identified lessening in competition; and

3. that the benefit of extending the arm's length rules would exceed the costs of that intervention, questioning:

   a. Does it prevent distributors from investing in NWAs on a competitive basis with other industry participants?
   b. Are there any, or sufficient, alternatives to the distributor providing the NWA itself? (our experience would suggest that there are few options of parties for consumers to choose from, currently, as their enabler of flexibility, and often consumers approach us directly to provide that service)
   c. Does it stifle innovation in new products or services?
   d. Does it prevent distributors from efficiently managing networks for the long-term benefits of consumers?
   e. Are there additional administrative, compliance and transactional costs for regulators and industry participants?

***Q34**. Do you agree with the Authority that Option 1 should be implemented, and that Option 2 should only 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?*

Our response to **Q34** is similar to our responses to Q32 and Q33.

In short, we reject the notion that distributors are using, or will use, their monopoly position in distribution to secure an advantage in contestable markets for flexibility services. Our priority is delivering the lowest cost solution to our consumers that meets our standard for delivering electricity distribution services.

We have demonstrated our intent to procure NWAs in preference to traditional investments, are our intent to procure those from the market. Even if we did not, as the CEG Report attests, it can be efficient for distributors to self-supply flexibility services.

Overall, we support the Authority using information that is already a part of distributors' information disclosures to the ComCom to monitor distributor's behaviour in contestable markets (Option 1).

With regard to Option 2, we reiterate our responses to Q32 and Q33 that the ComCom is ultimately responsible to consumers to ensure that regulated monopolies are not behaving in an anti-competitive way. We agree that the Authority does not need to impose arm's length rules.

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?*

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

While Vector accepts and agrees with the need for collective capability building in the sector, and the importance of industry collaboration, we think there are already sufficient fora emerging to stimulate this development.

Those groups with which we are working currently include:

1. The Northern Energy Group, comprising distributors in the top of the North Island
2. The ENA's Smart Technology Working Group (STWG), which itself is aiming to increase its collaboration with the rest of the sector and repurpose itself into the Future Networks Forum
3. The 'Big Six' group of distributors
4. The ENA, more generally
5. The FlexForum, of which we were a founding member.

We also note a number of multi-distributor workstreams emerging, including Orion and Wellington Electricity's ResiFlex initiative and the EECA/EEA demand response trial.

We agree with the Authority in para 6.16 that the duplication of capability and systems across all 29 distributors is unlikely to be the right answer, but think that collaboration on capability is happening, and will continue to develop, organically.

The most useful support the Authority could offer in this space would be to create an environment that supports learning by doing. This is a key theme of the FlexForum's submission, which we support. Part of this would be showcasing and highlighting exemplars of collaboration for others in the industry to aspire to.

NEG chief executives

Operating agreements for flexibility services

A more complex future highlights the need for deeper relationships

As we discussed in the introduction to this submission, the interrelationship between the growing penetrations of DER on our network, the operators (managers) of that DER, and us, is of critical interest to us.

Given how important it is becoming for distributors to actively understand, monitor and manage the operation of flexible DER on their networks, and to ensure that the DER only operates within the physical and power-quality limits of the network, we had expected this relationship to have been given a greater focus in the Issues Paper. The scope of the operating agreements contemplated in the paper are really limited only to those where a service is being provided by a DER manager to the distributor, for financial compensation.

We consider that operating agreements should be in place for <u>any</u> commercial operator of DER on our network, regardless of whether they are providing us a service. These parties are analogous to generators or loads that connect directly to Transpower's network, and certainly have operating agreements with Transpower. As noted in the FlexForum's insights paper, which we quoted in our introductory comments, Transpower's scheduling, pricing and dispatch (SPD) model ensures that grid-connected generators stay or operate within the physical limits of the transmission network, but no such mechanisms exist for distributors to provide their consumers with the same safety.

Therefore, in this section we highlight our concerns, and propose some potential solutions.
We will need to operate our network in a future world of millions of DER and myriad DER Managers, so we worked with expert consultants NERA to develop a suite of tools and options that enable efficient operation and a framework to assess those options. Their report is appended to this submission, and the highlights are summarised in the box below.

NERA report: The operating tools distributors need to oversee DER management and defer investment with certainty

Vector's Symphony strategy is predicated on flexible DER on our network being orchestrated with sufficient certainty and granularity to minimise the need for our network to be expanded and upgraded to meet the increases in demand forecast over the next three decades.

In a future in which the management of consumers' DER would be contestable service, we tasked NERA with developing a suite of options that would enable the overall network cost minimisation objective, and a multi-criteria framework for evaluating them.

In setting out its problem definition, NERA highlights that:

- Either managed load (by a distributor or third party) or market-based flexibility could be used to deliver the benefits of EV charging flexibility – there are pros and cons to both approaches
- Due to limited diversification of charging with smaller numbers of consumers, due to limited diversity the greatest impacts of rapid EV uptake will be at low voltages – for many distribution assets in Auckland, fewer than five residential customers sit behind them. A change in behaviour by a single consumer can have a material impact. Therefore, in planning investments for very local network requirements, including with NWAs, there is effectively no 'market' depth or liquidity, and may never be
- There is (currently) no market price signal to provide the granularity of distribution-level EV response required to defer investment in LV assets
- Transaction and coordination costs may be prohibitive for customers and flexibility

traders, and will require distributors to enhance their capability

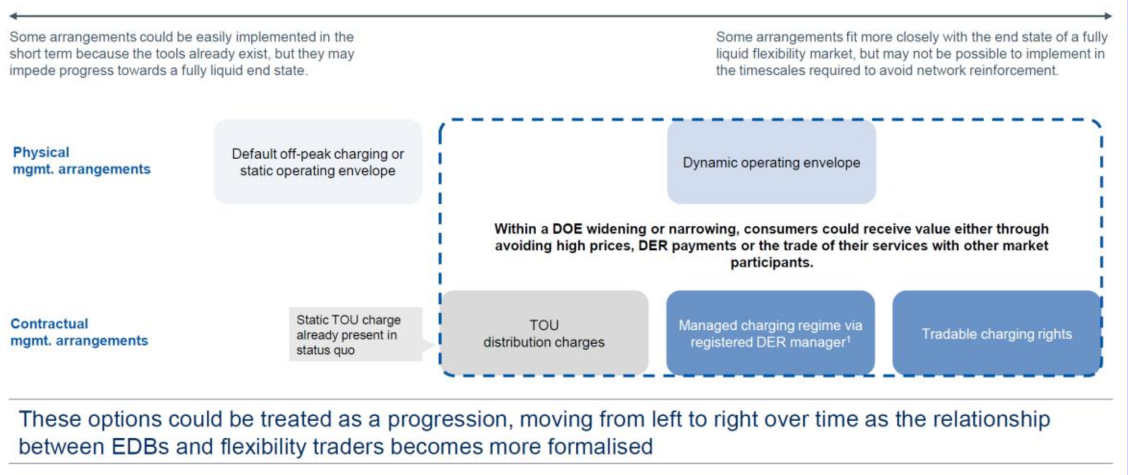
- Networks have a long-term commitment to customers and regulators, and thus seek long-term, "bankable" solutions to security of supply. They note that "*If a contract ends without replacement and the EDB was insufficiently diversified, it may need to carry out network reinforcement to replace the contract, or risk jeopardising the security of supply. A network solution cannot simply be implemented overnight and cost the same as if it were planned in advance.*"

NERA highlights international precedents for managing EV charging, including the UK's default off-peak regulations, and the dynamic operating envelopes being implemented in Australia. They also highlight the powers that Transpower has in Part 8 of the Code to instruct parties, in emergency situations.

NERA present a multi-criteria assessment framework for options, with the criteria assessing whether each option:

- Provides long-term certainty, enabling distributors to defer investment
- Provides granular certainty, enabling distributors to efficiently manage constraints
- Is implementable in the near future
- Is consumer-centric
- Allows for transition over time to a full flexibility market

Overall, drawing on experience from the UK and Australia, NERA presents a range of options, covering both physical mechanisms and contractual mechanisms, that could be treated as a progression as capability in the sector increases:



NERA concludes:

1. Default off peak charging and the EDB as default DER manager can be implemented immediately. Users who opt out of off peak charging could possibly be enrolled with the EDB (if not another DER Manager) to manage charging separately.

2. A dynamic operating envelope and tradeable charging rights will require technical and regulatory development, but are closer to the end state where flexibility traders maximise the value of services that can be provided at any given time, within the physical and power quality limits of the network.

3. In any event, some mechanism for signalling the physical capability of the local network at a given time is necessary to ensure that EVs do not create emergency situations. This can either take the form of a static operating limit or a dynamic operating limit, where the latter *would allow EV owners to charge faster when realtime system needs allow it. EDBs may require additional emergency powers that allow them to manage DER during emergency situations.*

Our view is that, while the appropriate mechanisms for procuring flexibility (e.g. contracted flexibility, price-response or another method) will take time to develop, implementing dynamic operating envelopes and emergency orchestration powers will be essential to enabling safe and secure value stacking by DER, regardless of how the future plays out.

Fortunately, there is a window of opportunity now to put the right settings in place to enable DER value stacking safely, while giving distributors the certainty they need to plan network investments efficiently – including deferring those investments. We think there are at least two specific requirements for the operating agreements between DER Managers and distributors:

1. **Dynamic operating envelopes, to reflect to DER Managers the physical and power quality constraints on a particular part of the network at a particular point in time**
2. **Emergency powers and procedures, enabling distributors to orchestrate all DER activity to safely manage emergency situations on their networks (and to assist Transpower in safely managing national emergencies on the transmission grid by providing sub-GXP coordination).**

Managing emergencies will require more complex orchestration in future

In relation to the second requirement above, NERA references the powers Transpower has to manage emergencies, in Part 8 of the Code. As above, we think the role of distributors will begin to mimic that of the System Operator more closely over time and as the number of DERs grows, and the Authority needs to consider how distributors are given the ability to orchestrate good outcomes for consumers in such situations. At the start of this submission we referenced how important this is for situations like the recent weather events in the North Island.

Transpower's emergency powers, set out in schedule 8.3 of Technical Code B of Part 8 of the Code, are extensive. Further, obligations of asset owners, and technical standards for assets for BAU operations (to avoid emergencies) are set out in schedule 8.3 of Technical Code A of Part 8 of the Code. Similar obligations should be extended to relevant parties, for the protection of the distribution network. We strongly recommend that the Authority reviews these aspects of the Code, in particular, with a view to understanding what parallel powers must be introduced for distributors and progressing that development. While we have not provided equivalent drafting at this point, we would welcome the opportunity to work with the Authority on this issue.

If distributors are enabled with better visibility and emergency powers for local network emergencies, they will be well placed and equipped to support system-level emergencies such as the 9 August 2021 event. As noted in the Authority's Phase 2 report, *"… the system operator had inadequate real time visibility of demand side participation – the resources expected to be available. Further, the system operator had inadequate awareness of the actions taken or planned to be taken by EDBs and direct connect consumers, and the discretionary load available through the ripple control of each EDB. … it was desirable to shed controllable load (e.g., ripple controlled load) before disconnecting consumers. Shedding load, such as ripple controlled load, would have avoided consumers being disconnected on 9 August."*[15] With a wider application of the Load Management Protocol, all managed DER, whether via retailers or third-party DER Managers, would be accessible to distributors in emergencies so that Transpower would have a clear process to ensure, through communication with distributors (rather than directly to DER Managers – something that

[15] Available online at: https://www.ea.govt.nz/assets/dms-assets/30/9-August-2021-demand-management-event-Phase-2-Report.pdf

could exacerbate local emergencies), that discretionary load is shed prior to disconnecting consumers in system level emergencies.

As we noted in the introductory section to this submission, the recent floods in Auckland, followed by Cyclone Gabrielle, are an extremely pertinent example of why DER orchestration is important to distributors, in this instance, for local or network emergency management. The potential activity of DER on our network in such events will need to be significantly constrained, while our operations centre undertakes temporary network switching, field crews are on the ground and repairing assets, and networks are carefully brought back online post-outage.

This highlights that the only party with full visibility of what actions from DER can be accommodated at any specific location on the network, and any point of time, is the distributor. If distributors were to have visibility, and some surety, of DER activity, and load in general, this would make those situations significantly safer to manage and could avoid cascade outages from simultaneous load restoration. Hot-water cylinders will be cold, and EV batteries may be empty after a prolonged outage. Having these devices attempt to turn on immediately as the network operator attempts to restore the network will make the job that much harder.

These situations may create new opportunities for NWAs as well – in some emergency circumstances it may be possible to restore power to additional customers if networks are able to confidently manage discretionary loads or injection by consumers adjacent to damaged areas of the network. By managing discretionary load from consumers on those shared assets (e.g. the upstream feeders) the limited capacity of backup equipment could be able to restore additional customers at reduced levels while the primary equipment that typically serves those customers is being repaired.

Existing coordination mechanisms are a start, but are unlikely to be sufficient

We think there are a range of different ways these issues could be addressed by the Authority. These include amending Part 6, as we discuss in the following section.

As set out in the box below, the foundations are already in place for operators of DER that are also retailers to enter into agreements with distributors to coordinate the management of that DER via provisions in the Default Distributor Agreement and specifically the Load Management Protocol (LMP). In our view, the LMP is the default *'operating agreement'* available for distributors to coordinate load management activities with retailers.

However, it has limitations. Specifically, the gaps we see are (i) it does not extend to parties managing DER who are <u>not</u> retailers and (ii) it only really contemplates load management coordination for the purposes of managing System Emergency Events. However, it needs to go further. Distributors need to also be able to reflect the physical and power quality constraints on parts of our network so that DER Managers can manage load within these constraints (or dynamic operating envelopes), <u>to avoid System Emergency Events from arising in the first place</u>. We intend to include terms addressing these physical and power quality constraints through the provision of dynamic operating envelopes to DER Managers, in our load management protocol.

The Load Management Protocol (LMP) under the DDA

The DDA, published by the Authority in 2020, recognises the potential for parties other than distributors to acquire the contractual rights to manage consumers' load. These are set out in clauses 5.1 and 5.2 of the DDA, with arrangements for incumbent rights to manage load in 5.3.

It is common ground in the industry that managed load and injection from DER, or "flexibility", will be a key feature of the future electricity system, bringing a “stack” of value across multiple parts of the system – from wholesale, to networks, and directly to the consumers themselves. What is less settled is the “how” this value will be realised – a question which essentially birthed the FlexForum in 2022.

In developing the DDA, the Authority recognised that either the distributor or retailer will be wanting to manage load, and that this will require coordination between the retailer and the distributor. How load is *dropped* is, generally, of little concern to a distributor, but how it is *restored* can be significantly disruptive. Further, continuance and restoration of supply, during and following outages, requires precision in how and when load is dispatched on the network.

Clause 5.6 of the DDA therefor requires a retailer who acquires the right to manage load to notify the relevant distributor, and then to develop and agree a LMP with the distributor. The protocol will ensure that use of DER in emergency situations is well coordinated. Clause 5.6 further requires that the retailer manages their load “as a reasonable and prudent operator in accordance with Good Electricity Industry Practice”. Poorly operated or coordinated load management has the potential to lead to a number of bad outcomes for the network and for the consumers it serves, including equipment failure, voltage excursions and blackout.

Vector does not currently have a protocol in place with any retailers on our network, but in 2023 we are intending to develop and agree one with any retailers who notify us, as per the DDA, that they are managing load on our network.

However, while the DDA has put in place the building blocks for coordinated DER management between retailers and distributors, no such provisions exist for coordination between *other parties* managing DER who are not retailers, such as load aggregators and other dispatchable load purchasers. Vector had included such a provision in clause 6.11 of its Use-of-System Agreement, requiring any third party with whom the retailer’s customer had contracted for load management , to enter into an operational protocol with Vector.

We had suggested that these provisions be included in the DDA, however the Authority did not agree. Realistically, placing the onus on the retailer to ensure the customer ensured the third party coordinated with Vector was sub-standard – a direct relationship between the third party and Vector is preferable and will only come about if the Code (or similar) imposes this requirement. We suggest this change be considered alongside other DDA-related Code changes. Given that DER-managing participants are likely to build national portfolios, across multiple distribution network, a degree of standardisation may be desirable.

With the introduction of Dispatch Notification in April 2023, and the blindness any party other than the distributor has of real-time network constraints when they (and the System Operator) are dispatching ever-increasing quantities of DER on distributors’ networks into the wholesale market, **it is now critical that the enabling framework for aggregator-distributor operational protocols is put in place**.

While developing such operating protocols between DER Managers and distributors would be a good place to start, in order to assist the development of such protocols we suggest that the Authority amend the Code to provide some clarity (or provide iterative Guidance) on what such agreements can contain. Ideally, too, the agreements would have a high degree of uniformity across retailers and other DER Managers, as consistency will become critical for distributors – especially in emergency situations. However, this is not what is contemplated in the DDA’s LMP. While the DDA itself is effectively a standard-form agreement between the distributor and all retailers on its network, the LMP will not necessarily be so – it is arguably anticipated to be a bilateral agreement between the distributor and each individual retailer. An option may be to add the LMP as an additional schedule to the DDA (either as a standalone schedule, or as part of schedule 4 to the DDA).

Given how important this is to us, we would be happy to engage further with the Authority on this topic and assist where we can in the development of appropriate settings.

Relatedly, NERA also reference the UK's precedent in introducing default off-peak charging for residential EV chargers – a form of static operating envelope. NERA notes that "*Residential customers generally do not buy EVs with the intention of providing flexibility services, which will be increasingly true as EV ownership spreads to wider populations. In other words, it's an old problem in a new world: disengaged retail customers are now disengaged EV owners.*". Default off-peak charging would be a simple way to ensure that at least a cohort of consumers, likely those unwilling to engage deeply with the electricity sector, would be charging their EVs outside of peak periods, therefore reducing costs both to themselves and the wider consumer base. We think a similar requirement in New Zealand would be a "no regrets" move by the Authority, although the Authority would need to coordinate this work with EECA who are already looking at standards for smart chargers. This should be advanced as a high priority.

In Appendix [C] we have copied the UK's regulations enabling off-peak charging by default, for the Authority's consideration. As noted above, we strongly encourage the Authority to work with its agency partners to introduce equivalent regulations in New Zealand. As can be seen, they are relatively straightforward but would have a significant impact and provide a valuable backstop for those consumers who choose not to be engaged in more sophisticated operation of their DER.

***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?*

***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?*

***Q39**. Do you have any suggestions for how the Authority can support industry-led work on providing guidance on best practice and templates for operating agreements?*

We agree that there are significant benefits in establishing some common contracting arrangements and terms of trade for procuring NNS, noting that some flexibility will be required to cater for specific circumstances and requirements. This will reduce transaction costs for both buyers and sellers of flexibility. However, there will be a significant degree of complexity in these arrangements, and allowing market standards to emerge organically, commercially, is by far the best approach at this point.

While there are some existing precedents already, we think the best way to build some uniformity is for the Authority to support learning-by-doing approaches that build on each other, and to promote transparency where possible. The Authority's Market Monitoring team should have a dedicated stream analysing how the market is developing and identifying and assessing both good practice and emerging barriers.

As noted in the FlexForum's submission, risk allocation and risk management is a critical hurdle to overcome when contracting for flexibility services. As DER is not yet ubiquitous, most providers of flexibility will need to deploy new solutions onto distributors' networks, some of which will require individual consumers to take up and possibly invest in the technology. Therefore, at this point of time, there are two major issues driving risks of non-performance by a flexibility supplier – not being able to deploy enough technology, fast enough, and then that technology not performing as required and expected. These risks create the need for a 'Plan B', which creates extra costs either for the buyer or seller, which then need to be recovered.

A six-monthly or annual progress / monitoring report by the Authority would be an excellent place to start to build increasing awareness of emerging best practice. This could include some element of overseas monitoring too, to ensure that best practice from overseas is being picked up. The Authority could work in concert with, and/or support the FlexForum in undertaking this task, as supporting practical application of flexibility services is a significant focus for that group.

DER standards

As per our comments at the beginning of the last section, and earlier in the document, there are some material enhancements that need to be made to the Code to ensure the future system with millions of connected, flexible devices, is able to deliver long-term benefits to consumers.

In that section we highlighted what we see as some of the future requirements, including more advanced congestion/constraint management by distributors, more sophisticated capacity allocation, and coordination of DER operation during emergency situations.

It may be that Part 6 is the right place to introduce those requirements into the Code, or it may be that it fits elsewhere in the Code. While we offer some suggestions in this section, we would like to work with the Authority and the rest of the industry to determine what needs to be put in place, and what the appropriate vehicles are for introducing them.

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

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

As mentioned above, and earlier in the submission, one of Vector's top priorities is to put in place the settings that will enable the full value of DER to be unlocked in ways that minimises total costs to consumers. We are strongly supportive of the Authority undertaking a full review of Part 6, and request that its scope includes:

- The possibility of expanding the rules to cover all DER, not just distributed generation (DG)
- Ensuring the visibility (at least to the distributor) of where that DER is, what its technical characteristics are, who is operating it and how it is operating
- Clarifying how the distributor can and will manage congestion on its network, including from excess demand (i.e. not just congestion caused by excess generation)
- Clarifying how the distributor can and will manage emergency situations on its network, including what it will require from the operators of DER

Part 6 review should include issues at installation and registration

While these are our highest priorities for this review, we would recommend more specifically that any proposed review of Part 6 includes:

1. <u>Changing the timeframe for the Certificate of Compliance (COC) to be provided to no later than 10 business days after the installation/livening of the DG.</u> Under existing Code requirements, the COC is to be provided after the approval of the application. This does not make sense since the COC cannot be done until the installation has been carried out.

2. <u>Consider putting the responsibility for applying and providing the COC on the solar installer (or their chosen agent) rather than the generator (end consumer).</u> This would make more sense as most end consumers are not even aware of the Authority and the Code's existence, let alone the Code obligations that may apply to them. While the Authority does not regulate solar installers, this would likely lead to a higher level of compliance with the requirements than the status quo.

The rules around the application process for DG could also be revisited to improve the information that distributors have about DG as well as streamline the process. Customers are currently obligated to notify distributors of inverter replacements, upgrades to their DG connection, and provide the COC for any completed installations. This would likely be better performed by equipment installers rather than the customer.

Our records show that we respond to new DG applications in an average of five days, however it can take months for an installation to occur and be reviewed by a qualified inspector to finalise that new DG connection. In some cases, customers decide not to move forward with an installation after receiving approvals, or they forget to send in the COC. In order to resolve these issues, we must follow up directly with those customers to identify what has happened.

In a scenario where millions of DERs are being connected to the network, distributors will not be able to chase down each consumer who changes their mind or forgets to send in their COC, so a review of this process would be beneficial. In some cases, a customer is unaware of the requirement or is not informed of their obligation to inform the distributor of the installation of DG. This endangers the community, and our field crews, in the case of outages or maintenance. We envision that this can be resolved through better access to smart meter data, as discussed in the earlier section on data access.

***Q42**. What are your thoughts on amending Part 6 to explicitly include DER, and what do you think are the key issues to be considered?*

DG poses a set of risks that need to be (partially) managed/addressed during the application process, e.g. batteries, V2H or V2G chargers that operate in parallel with the grid as DG. Other than registering other (non-injecting) DERs to get some visibility, DER may not be a ‘natural fit’ for Part 6. The Authority should consider whether putting in place DER-related provisions under their own section in the Code is more efficient.

It would be impractical to expect everyone to apply/register each device that meets the criteria when these devices become more widely available (e.g. smart fridges or heat pumps). Many appliances are being sold today which have wireless communication capability, yet the owners will never use it. The Authority could also consider requiring the registration of a device when it is offered into a demand management programme and/or starts being actively managed by a DER Manager (‘managable DER’). We understand that, in the UK, enforcing compliance with the requirement to register low-carbon technologies has been a challenge.

In our view, it is critical that Code provisions on congestion management, and what is expected in the distributor’s congestion management policies, should be extended to all DER. This should include opportunities for distributors to provide DOEs as guardrails to DER Managers and should clarify the distributor’s rights to instruct in emergency situations.

DER managers would be required to adhere to these operational constraints to ensure that their DERs do not cause congestion or negatively impact other consumers by forcing the local network to exceed its physical limits and potentially causing System Emergency Events on the network. It is important to note that the congestion management policy should be tailored to suit the specific needs of the distribution network and the DERs connected to it.

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

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

We consider a threshold of >30kW to be reasonable, as there are different requirements for systems of this size in 4777.1:2016 (e.g. secondary central protection relay).

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

If the timeframe for Part 1A applications is to be changed, we would suggest slightly lengthening the timeframe.

While we currently have no issues adhering to the 10-day timeframe for <10kW applications, the average time is has taken us to process applications has been slowly increasing as the application numbers increase. Extending the timeframe would help accommodate this expected increase in demand.

We suggest that the Authority consider moving to a 15-business day timeframe; the extension does not have to be much. We are considering implementing some improvements that would help reduce manual workload such as using an online application form rather than a Word document, etc.

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

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

Vector does not have any issues with the current approval timeframes in Part 1 and Part 2.

***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.*

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

Vector suggests that a clearer set of requirements be defined by Transpower for DG >1MW.

We note that New Zealand does not have a 'renewable grid code' which many other countries do[16]. These grid codes specify the types of studies required to prove that generator(s) can connect safely without adverse effects. Grid codes can also specify the type(s) of DER that should adhere to controls and the power reduction and power restoration ramps for safe operation.

IRENA published a report on Grid Codes for Renewable Powered Systems in April 2022[17], which summarizes some of the important aspects of a Renewable Grid Code. IRENA notes, "*Grid code requirements were previously only applicable to larger users, but they should be extended to smaller users as well. This would enable new user types to connect in a system-friendly way, by specifying corresponding requirements for them and adapting to the state of technological development and system needs*." In the report, IRENA suggests a reliable cadence of reviews, studies, and updates to the code to ensure that the code remains relevant to all parties.

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

We recommend a review of the performance of Transpower's recently-changed application queuing rules, and consideration of whether similar requirements for distributors would be suitable.

***Q51**. What are your thoughts on reviewing the priority of applications clause in Part 6? Should the AS/NZS 4777.2:2020 Standard be mandated for inverters in New Zealand? If so, how should this be accomplished?*

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[16] South Africa example available online at: https://www.nersa.org.za/wp-content/uploads/bsk-pdf-manager/2022/01/SAGC-Requirements-for-Renewable-Power-Plants-Rev-3.1.pdf

[17] Available online at: https://www.irena.org/publications/2022/Apr/Grid-codes-for-renewable-powered-systems

We believe that the AS/NZS 4777.2:2020 Standard should be mandated, but only for smaller household inverters. Larger inverters may be certified for different standards. In general, all inverters will have the same capabilities (protection and control), but larger installations with correspondingly larger inverters must go through a more detailed application process where the checks and balances are in place to ensure correct settings/operation, whereas smaller household inverters can use a streamlined application process and we rely on the use of modern inverter standards to ensure the safety of the network and our field crews.

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

No comment.

Appendices

Appendix A – NERA: Promoting Efficient and Affordable Infrastructure to enable electrified transport

Appendix B – CEG: The relative efficiency of self-supply vs arm's length supply of flexibility services

Appendix C – UK regulations to require off-peak charging by EVs, by default

The Electric Vehicles (Smart Charge Points) Regulations 2021

Source: https://www.legislation.gov.uk/uksi/2021/1467/contents/made

PART 2 Requirements in relation to charge points

10. Off-peak charging

(1) Subject to paragraph (2), a relevant charge point must be configured so that—

(a)it incorporates pre-set default charging hours which are outside of peak hours;

(b)when it is first used, the owner is given the opportunity to—

(i)accept the pre-set default charging hours;

(ii)remove the pre-set default charging hours; or

(iii)set different default charging hours;

(c)at any time after it is first used, the owner is able to—

(i)change or remove the default charging hours if these are in effect;

(ii)set default charging hours if none are in effect.

(2) The requirements in paragraph (1) do not apply where—

(a)the relevant charge point is sold with a DSR agreement;

(b)the relevant charge point is configured to comply with the requirements of the DSR agreement; and

(c)details of the DSR agreement are included in the statement of compliance in accordance with the requirements of paragraph (2)(b) of regulation 13.

(3) A relevant charge point must be configured—

(a)to charge a vehicle during the default charging hours (if any), save that the owner of the relevant charge point must be able to override the default mode of charging during the default charging hours; and

(b)so that the owner of the relevant charge point is able to override the provision of demand side response services.

(4) In this regulation—

(a)“default charging hours” means a default period during which the relevant charge point charges a vehicle regardless of what time the vehicle is first connected to it;

(b)“peak hours” means 8am to 11am on weekdays and 4pm to 10pm on weekdays.