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The future operation of New Zealand's power system – Vector response to consultation paper

Vector appreciates the opportunity to provide comment on the Electricity Authority's (the Authority) *"The future operation of New Zealand's power system"* consultation paper (the consultation paper)[1]. This submission is not confidential and can be published in full on the Authority's website.

Vector appreciates the comprehensive review of the existing power system arrangements that the paper sets out in section 3. We agree with the overview and also broadly with the description of some of the key drivers of change in section 4 of the paper. We comment on aspects of section 5 of the paper, namely in relation to some of the challenges and opportunities for the power system in responding to these key drivers of change. In summary, these relate to the changing roles and responsibilities for Electricity Distribution Businesses (EDBs) and the changing dynamics for the power system, as these complexities increasingly take a hold in our power system. The only constant will be change. We need to ensure our power system arrangements are agile enough to respond to (constant) change and that market participants roles and responsibilities evolve accordingly, in order for us to continue, collectively, to meet consumers' needs.

Vector's key points of submission

The following key points must be front of mind for the Authority as they process submissions and develop the next stages of the Future System Operation workstream:

- Coordination of system operation on, and between, distribution networks will be at least as critical in future as vertical coordination across the value chain. The role of the EDB is changing significantly, in New Zealand and globally. This has not been an area of focus for the regulator or industry to date, but must become so immediately. There is significant collaborative effort underway to develop systems and processes in this space, including by Electricity Networks Aotearoa's *Future Networks Forum*.

1 Available online at https://www.ea.govt.nz/projects/all/future-security-and-resilience/consultation/future-operation-of-new-zealands-power-system/

- Third-party management of distributed resources on EDBs' networks is relatively nascent in New Zealand, but operating protocols must be put in place before scale increases. Done well, management of distributed flexibility can save investment and operating costs across the entire system, delivering significant consumer benefits. However, this must be done in a way that keeps networks and consumer supply safe and stable. Parties offering portfolios of resources into the wholesale market, or in response to other market signals, must be aware of the physical and power quality limitations of the networks relative to the individual resources in their portfolios. There must be clear protocols in place specifying how operating limits are to be respected and local and national emergency events managed.
- Actual and perceived conflicts of interest on distribution networks are already being managed, through a wide range of mechanisms. These controls must continue to evolve over time. Parallel mitigants within Transpower have evolved progressively over the past 30 years, emerging as and when required. Potential conflicts should be identified, named and monitored, with controls developed only when the case has been made clearly. As a case in point, self-supply of services by EDBs can be efficient, and it may not be in consumers' interests to limit this.
- There are significant interdependencies between a number of different regulatory workstreams across the jurisdictions of the Authority and the Commerce Commission. These include future system operation, regulatory settings for distribution (including operating protocols, Part 6A requirements and commercial access to data), distribution pricing, streamlining network connections, financeability of new investment, evolving service quality metrics (for a world in which third-party DER management is prevalent), and flexibility in funding allowances (opex versus capex). It would help stakeholders significantly if it could be made clear how these workstreams are being managed collectively to ensure the end results deliver long-term benefits to consumers.

Evolved distribution system operation is a significant area of focus: *the role of the EDB is changing*

Done well, efficient orchestration of DER can bring major benefits to consumers in terms of reducing investment and operational cost across the whole system – i.e. whole-energy-system-cost (WESC) reduction. However, achieving this requires significant shifts in industry operation.

The largest sea change described in the paper is for distribution networks to become a more active extension of the national system, with distributed resources (both demand and supply) playing a more active role in a highly renewable system. Where previously EDBs had been able to operate relatively independently, from each other and from the national system, in future the demand-side resources on one EDB's network could flex to balance changes in the renewable distributed generation output on a neighbouring network – or the renewable resources connected to the transmission network, many hundreds of kilometres away. Market participants will be actively managing and trading resources hosted on many (or all) different EDBs' networks and will need consistent approaches from their hosts to do so.

Further, an increase in the synchronisation of demand-side resources on the network implies a reduction (or destruction) of the natural diversity of demand that distribution network planners have been able to refine and rely on for the past century. Where previously not everyone cooked their meals, watched TV, bathed or turned on their heating at the same time, in future we could have more and more devices responding to the same, external signals coming from the wholesale market or national system – for example all hot-water cylinders on the network attempting to be dispatched 'on' in response to an increase in low-cost wind generation hundreds of kilometres away, or all batteries on a network discharging in response to a rapid fall in system frequency. This implies a significant departure from the status quo that has prevailed during the development of the Electricity Code and our regulatory frameworks. It also confounds the extent to which we are building networks to purely meet consumers' needs versus enabling the commercial opportunities aggregators are seeking to explore.

The increasing level of interconnection demands a level of operational alignment and consistency between EDBs, with aggregators, and with the transmission system operator, not previously seen to date.

Within this future context, EDBs have a critical role to play to support innovation and enable greater consumer choice. We and other EDBs have been considering some of the shifts in context shaping the future, and how our roles will evolve to ensure we continue to deliver for our communities. We are now seeing levels of collaboration not seen before, in groups such as ENA's Future Networks Forum, the Northern Energy Group (NEG), and the FlexForum.

In today's world, EDBs are the Distribution Network Operator (DNO) with responsibilities for the safe, secure and reliable distribution of electricity to our connected customers. Distribution system operation is still required, but in a relatively passive way. Even though EDBs have a responsibility to maintain supply voltage to consumers, the use of distributed energy resources (DER), currently at relatively small sizes (kW per installation) and levels of penetration (number connected to individual network assets), is happening relatively independently of the EDB networks that host them. To date, this has not led to issues; at today's scale, the swings in output and or demand caused by the operation of DER are rarely large enough to impact network operation or violate network constraints.

Tomorrow, with the anticipated growth in DER, EDBs' roles will naturally evolve to include both our traditional DNO responsibilities and much more active distribution system operation. Given the expected growth in size and penetration of DER, an increase in the use of flexible resources by DER Managers cannot continue to happen independently of the host EDB. We will be expected to play the role of 'energy orchestrators' as the primary entry point into the electricity system for new actors such as prosumers and aggregators. As Distribution System Operators (DSOs), we will foster engagement and interaction with stakeholders, unlocking a flexible system that creates new opportunities for innovative energy services and shared value.

Accordingly, we disagree with the statement at Table 1, page 19 that "no directly equivalent role" exists for Distributors under the heading "system operation". Much of what is described under "asset ownership" is in fact **system operation** for distributors (i.e., maintaining power quality and the security of the distribution networks under their control, including monitoring voltages and power flows). Asset ownership through a distributor's control room would include such things as looking at overloads and faults and restoration and should describe the work that planning and operational teams undertake for construction and maintenance of the network.

Coordination will be required at both the national grid (vertical) and network (horizontal) levels

We agree the operation of the transmission and distribution network will become more complex and interdependent over the coming years, both in real time and over the typical planning horizons for the industry. Some of the factors driving that complexity are increasing demand for electricity, more variable and intermittent generation, more DER creating bi-directional power flows, and a vast increase in the number of power participants. The need for coordination will be critical.

The importance of coordination between the transmission and distribution levels of the power system is emphasised in the paper, with an overview of international jurisdictions the Authority has considered outlined. The need for coordination at the *next* level of the power system, i.e. from the distribution network level to DER Managers, does not, however, appear to be on the Authority's radar. The need for coordination at this level will be just as critical, for the reasons noted above, including that the vast majority of responsive resources (by number) will be connected to the distribution network and that DER will either be actively or passively managed by DER Managers, with the potential to massively affect reliability.

Yet EDBs and aggregators – mostly retailers at this stage – have been left to negotiate and agree bilaterally the arrangements or protocols by which DER Managers will coordinate their flex activities with EDBs, under the DDA. We suggest some clarifications to the DDA in our response to question 4 below, and in the interim some level of regulatory guidance may be required to support these clarifications. The conversation on protocols must remain focused on DER Manager implementation methods for adhering to operating limits that safeguard the network. Such guidance would help accelerate the negotiation process for these protocols. . Otherwise, the protocols and relative priority rights within the spectrum of bespoke arrangements risk being misaligned when we look across all EDBs, and likely even between individual aggregators hosted by a single EDB.

As Vector has previously submitted, *"the role of distributors will begin to mimic that of the System Operator … and as the number of DERs connected to the network grows, the Authority should be considering how distributors are given the ability to orchestrate good outcomes for consumers in such situations."* [2] For both the short-term and long-term benefit of consumers, coordination efforts must apply at all levels of the power system – this allows for alignment in approach and leads to more efficient regulatory arrangements and a more efficient energy system.

Settings to enable smart, safe and stable DER orchestration

[2] See page 47,

In addition to the coordination points above, additional key requirements that will help enable increased coordination and smart orchestration on distribution networks include:

1. The Authority working with its Council of Energy Regulators colleagues to:
   - Make EV smart-charging standards, connection to a smart system, and registration all mandatory
   - Require off-peak charging for EVs by default (as per UK)
   - Ensure that cross-cutting regulatory settings enable industry participants and provide resources to support this vision
   - Improve the available DER data, and access to that data, for the whole sector
2. Empower the EDB to be the 'default' (or last resort) DER Manager on their network (as per status quo)
3. Provide EDBs with the powers to direct the response to emergency situations by the DER Managers on their networks – from grid emergencies to local, LV issues
4. Enable EDBs to avoid emergencies (referencing DDA cl 5.6) by ensuring distribution-level constraints (physical + power quality) are understood and adhered to by DER Managers on distribution networks. This needs:
   - A mandatory, 24/7 operating envelope at each ICP, that must be adhered to by DER Managers
   - DER Managers to ensure offers into wholesale markets stay within their operating envelopes

Enabling Code is the first-best solution for these things, and should be expedited.

In its absence, we are attempting to formalise 3 and 4 above in a 'load management protocol' with retailer DER Managers, as per DDA cl 5.6. However, no such mechanism exists to enable safe operation by non-retailer DER Managers (not currently industry participants to whom the Code applies) on our networks (and there is no indication that this is expected 'good electricity industry practice').

Evolving roles and responsibilities are being explored collectively

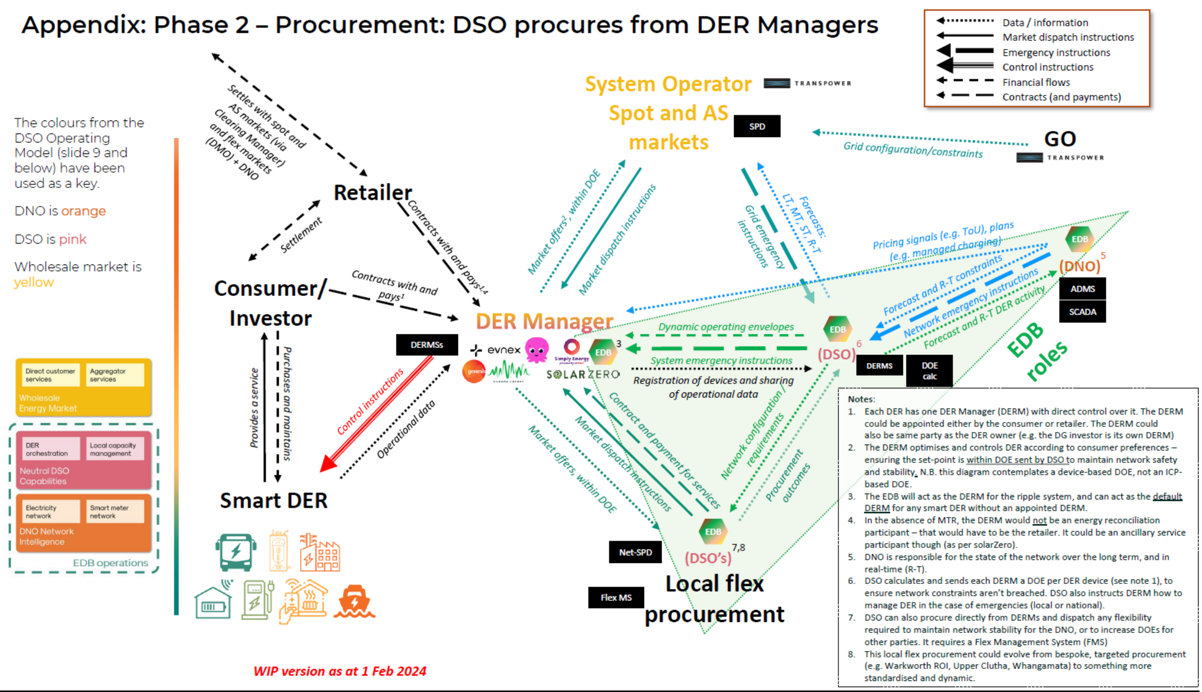
Vector contributed to the Northern Energy Group's recent publication[3] on the evolution of the power sector and the evolving role of the EDB. This publication highlighted the different phases of flexibility market development, and how the EDB role would need to evolve to support the increased activity of DER Management by retailers and other parties. This transition is reflected in the table below, taken from NEG:

[3] Available online at https://www.linkedin.com/feed/update/urn:li:activity:7165419774091481088/

	Status Quo	Phase 1 – Enabling	Phase 2 – Procurement
Phase of DER market development	**Limited relationship** and **interaction** between DER Managers and EDB	DSO **enables** safe DER management and 'value stacking' by emerging DER Managers	DSO begins to **procure** dedicated services and solutions from DER Managers
Active DER Managers in this phase	• EDBs (hot water, network batteries, other DER) • C&I consumer process managers • DG owners (e.g. hydro, wind, solar)	• As per status quo, plus: • Retailers and other aggregators (smart hot water, smart EV charging, e-buses, home batteries, etc)	• As per phase 1, but in even greater numbers and with a wider range of business models
Main DER management activities	• EDBs utilising DER for network management (i.e. *utility-led* mode) • DG owners optimising wholesale market revenues – either *passive* response to spot prices, or *active* participation in the market ('active' = offered to, and dispatched by, the TSO)	• As per status quo, plus: • New DER Managers responding to wholesale prices and TOU distribution prices (i.e. *price-led* mode). Either active (offered) and/or passive (non-offered). • New DER Managers managing 'flexible' network connections (e.g. bus charging)	• As per phase 1, plus: • DER Managers operating under market-procured contract to the DSO (EDB) for specific services, including investment deferral (i.e. *market-led / contract-led* mode)
Main DSO activities: • **local capacity management** • **DER orchestration**	• EDB and non-EDB DER Managers operate independently of each other • Limited active relationship between DSOs and DER Managers; EDBs may have little awareness of DER Manager presence • DER Managers have little, if any, awareness of network capacity constraints	• DSO will enable safe DER Management and value-stacking by providing static or dynamic operating envelopes to DER Managers • DSO will orchestrate DER response to network and grid emergencies • Over time, more sophisticated time-varying distribution pricing could emerge	• As per phase 1, plus: • The DSO will procure (via contract) specific services and specific responses from DER Managers, including investment deferral (non-wired alternatives) and ancillary (network support) services. • Over time, more sophisticated market and pricing mechanisms for networks could emerge

Evolving System Inter-relationships - The DSO will safely unlock and enable whole-of-system value from de-centralised resources (NEG - DSO Evolution, slide 10)

NEG highlighted how industry roles, responsibility, architecture and information flows may need to evolve to support these different phases, with the ultimate architecture diagram for phase 2 represented below (and also found at the end of this submission in a larger format):



NEG - DSO Evolution, slide 11 - A full page version of this graphic can be found at the end of this submission

NEG continued by setting out the activities requiring collaboration with regulations and Government decision-makers, which we support:

Success Criteria

What we're doing and where Government collaboration is required

Each of our member networks needs a clear pathway for necessary functions that is standardised and transparent but allows each EDB to move at the appropriate time. Across our networks we will have significantly different DERs/EV uptake, rate and timing of population growth, network realities, and equity considerations.

These are the core DSO functions NEG members are pursuing:

- Whole system orchestration
- Capacity allocation and management
- Asset and operations management
- Flexible systems and flexible network connections
- Digitalised operations and communications interfaces and standards

We are also participating in the corresponding workstreams of ENA's Future Networks Forum, which are aiming to deliver nationally-aligned solutions.

Activities requiring EDB collaboration with regulators and Government decision makers:

1. Ensure statutory regulations for EDBs (e.g. quality and reliability) remain fit-for-purpose in a world with market-based DER management
2. Establish minimum technology and communication standards to enable smart system management and interaction, and provide the allowances to invest in this capability (and the data required)
3. Develop – potentially through 'sandboxing' – a framework for the implementation and operationalisation of dynamic capacity management on distribution networks, including principles for how capacity is allocated between system users and the requisite communication protocols
4. Ensure that all parties managing DER on behalf of consumers and investors (DER Managers) have agreed operational protocols with their host networks, formalising the requirement on the DER Manager to manage within the operational limits of the network
5. Clarify the ability of DSOs to orchestrate the response of DER Managers to system emergencies – from the very local (e.g. car vs pole) to nationwide
6. Amend distribution pricing rules to ensure parties who benefit commercially from network capacity fund it
7. Enable commercial access to network operational data and ensure the minimum level of metering capability necessary to deliver it

Vector is also taking active part in ENA's Future Networks Forum initiative to provide guidance on the roles and functions required to unlock whole-system value from distributed flexibility.

Conflicts of interest are being managed, and controls must continue to evolve

The Authority rightly calls out the potential for conflicts of interest to emerge between the various roles that EDBs will play in future – especially DER operation, network planning and investment, flexibility procurement and distributed system operation – all of which NEG includes in the green triangle representing 'EDB roles' in the diagram above. We agree that the potential for conflicts to arise is real. Where we may disagree with the Authority, and likely other submitters, is in the likelihood of these conflicts leading to suboptimal outcomes for consumers, and the scale of those disbenefits.

The Authority usefully noted, in paragraphs 3.37 – 3.43, the existing mechanisms and controls used to mitigate the risks of the conflict of interest between the Grid Owner (GO) and System Operator (SO). While these are useful precedents to consider the future separation of duties between the DSO and DNO component parts of an EDB, what was missing from the commentary was the *timing* of when each risk may materialise, and when the need for each intervention may become pressing. The wholesale market, and the role of the SO, have existed for nearly 30 years, but these controls have only emerged and been implemented progressively <u>over the course of those three decades</u> – some pre-emptively as concerns have arisen, some following review of specific incidents. This suggests that the introduction of controls and separation at the distribution level also needs to be an evolution, as and when concerns become material.

We note there are existing controls to manage the risk of conflicts of interest at the distribution level:

- Part 4 requirements for EDBs to consider all cost-effective alternatives to traditional investment
- Arm's-length requirements in Part 6A of the Code
- Open, competitive access to DER management, defined under the DDA
- Rules governing related party transactions
- Regulated processes and terms for connecting distributed generation in Part 6
- Competition law

We are not suggesting the potential concerns be ignored until issues become clear; rather, potential conflicts should be named as soon as possible, and monitored regularly, with a clear set of criteria specified *ex ante* for when further investigation may be warranted. In the meantime, increased disclosures and further transparency may well be sufficient to alleviate any immediate concerns.

Ringfencing or separation of the DSO role from the DNO would be a massive step to take at present, given it can be efficient for an EDB to self-supply flex services in certain cases (noted later in this submission, with reference to expert advice received in 2022). Furthermore, Ofgem, which has enabled the development of DSO functions for over a decade in the UK, decided in late 2023 not to require separation of system operation from network ownership within an EDB. We recommend the Authority dive deeply into this important precedent[4], as Ofgem's consultation and decisions have been made since the EY report was completed over a year ago.

Standardisation and alignment between EDBs will become critical

We agree that distributors will need *"increasingly complex tools and processes to deal with increasingly complex operating scenarios across the power system and greater visibility"* of our low-voltage networks and assets i.e., DER connected to the network. Optimal utilisation of DER for the greater good of the power system, and the long-term benefit of consumers, relies heavily on common standards and protocols being established to unlock the potential of these resources. As the Authority notes in paragraph 5.8, *"For example, a common communication protocol would help enable dynamic operating envelopes (DOEs), which can facilitate a relatively more efficient allocation of network capacity to DER controlled by consumers and third-party aggregators – particularly for distribution networks that are close to capacity."*

With respect to learning from international jurisdictions, it is important we consider the detail behind both policy and regulatory frameworks for other jurisdictions that have led them down one path or another, and reflect on whether Aotearoa NZ needs to meaningfully change our existing frameworks to match a jurisdiction whose results we would like to emulate or whether we can follow other jurisdictions that more closely resemble our own circumstances and make gradual changes.

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[4] Available online at: https://www.ofgem.gov.uk/sites/default/files/2023-11/Future%20of%20local%20energy%20institutions%20and%20governance%20decision.pdf

An example of this can be seen in choices made on communications protocols for coordinating behaviour of flexible resources. Over the last decade, Australia has been managing constraints on their low-voltage networks from distributed solar generation by developing inverter-based standards. Australia is now looking at extending the CSIP-AUS protocol with additional components from the IEEE 2030.5 standard to enable the integration of more consumer devices.

Over the same period in the UK, DNOs and Ofgem coordinated regulator-supported innovation (370 innovation projects at a total cost of £271M were funded in RIIO-1) and "flex first" network planning philosophies to build a market-based approach that initially managed constraints on the high-voltage assets of distribution networks. We understand that distributors began with high-voltage assets in the UK partially because DNOs designed for (and consumers are paying for) much higher levels of low-voltage capacity than in either New Zealand or Australia. Accordingly, the UK has pursued open APIs and protocols such as OpenADR that have strong market-based mechanisms built in. Ofgem and DNOs are now expanding those market-based solutions to account for the growth and "herding" caused by electrification by consumers on their low-voltage network assets. Even after a decade of implementing "flex first" efforts, it is notable that Ofgem are still testing different market structures, communications standards, and other aspects of system operation associated with demand flexibility.

This demonstrates that understanding context and allowing evolution through real-world implementations is critical to designing the operation and regulation of the sector during this transition.

Vector's responses to questions in the consultation paper.

3. The current arrangements for power system operation in New Zealand

> Q1: do you consider section 3 to be an accurate summary of the existing arrangements for power system operation in New Zealand? Please give reasons if you do not agree.

We broadly agree with the Authority's summary.

What is apparent from this section is the dearth of Code or regulatory arrangements that consider the distribution network and facilitating efficient operation at that level. Other than the DDA for the provision of 'distribution services' to retailers, the Code is silent about how the distribution network ought to be operated, including expected behaviour in load management – an activity distributors have been engaged in for decades now with hot water control.

As significantly more DER comes onto the distribution networks, the management of these DER, by 'new players' (i.e., DER Managers) in response to situations and signals, and the implications those activities will have on both the distribution network and the national grid, will have to be considered. Ultimately a level of regulation will be needed to ensure coordination across the power system. Vector is simply indicating that it will not just be the provisions set out in Appendix A of the consultation paper that will need to be revisited, but rather whole chapters of new Code will be needed to ensure the next layer of the power grid is kept safe and protected for the benefit of consumers. Increasingly, over time, the distribution network will need to be operated consistently with the transmission system, and the role of the DSO will begin to mimic that of the TSO. None of the enabling Code required is currently in place. This thinking and work will also obviously need to align with the Distribution Regulatory settings workstream.

We disagree with the statement in Table 1, page 19, that "no directly equivalent role" exists for Distributors under the heading "system operation". Much of what is described in the "asset ownership" box of the table should be classified as system operation already occurring at the distribution level. This includes, for example, the focus on "*power quality and the security of the distribution networks under their control including monitoring voltages and power flows*", which could be further extended to include the control room management of outages and outage restoration. The "asset ownership" box rightly includes such activities as monitoring asset overloads and fault and should also include the work that planning and operational teams undertake for construction and maintenance of the network.

4. Drivers of change to power system operation in New Zealand over the coming decades

Q2: Do you agree that we have captured the key drivers of change in New Zealand's power system operation in section 4? Please give reasons if you do not agree.

We broadly agree with the key drivers of change noted in section 4 of the paper, although we consider the true underlying drivers are more fundamental than these, including evolving consumer preferences and uptake of new technology, Aotearoa's decarbonisation goals and commitments, decentralisation of the industry in response to technological change and decarbonisation efforts, and a need to maintain reliability, resilience and energy affordability. The drivers noted in section 4, particularly those relating to technology are more *enablers* of change in response to the fundamental drivers, and need to be accommodated or integrated with the power system.

Access to capital and cost of capital will be amongst the most critical factors to the sector being able to respond to and integrate the 'drivers of change' noted in section 4 of the paper. The ability of networks to sufficiently and efficiently finance their investment must be a key consideration.

We note at paragraph 4.27 of the paper that the Authority considers the *"SO should in due course be able to manage system constraints by <u>requesting</u> ramp up or ramp down of prosumer generation and demand through aggregators, or even aggregation technologies yet to be developed."* This might be a replication of the powers the System Operator has currently to manage grid emergencies under the Code which EDBs need to similarly have to manage system emergencies on their own networks. For the reasons noted above, and as Vector has previously submitted[5], *"distributors will increasingly need to have emergency management powers, similar to*

[5] See https://blob-static.vector.co.nz/blob/vector/media/vector-2023/vector-submission-issues-paper-updating-the-regulatory-settings-for-distribution-networks_1.pdf

Transpower's under Part 8 of the Code, for the protection of the distribution network as the number of DERs increases." It must be the EDBs who manage the response by aggregators to grid emergencies, rather than the SO, who has no visibility of the impact of those actions on the distribution network.

The EA notes at para 4.8 that 20% of energy consumed in Copenhagen city buildings is flexible. Similarly, hot water heating makes up about 30% of the average Kiwi household's energy use[6], which has been manageable by EDBs via hot-water load control systems. This flexible load has been available to manage constraints on both the grid and distribution network at varying levels of penetration across the country. Grid Emergencies are effectively constraints on the grid – when supply isn't available to meet demand, which then needs to be curtailed. Such a resource has been available to respond to grid emergency management, but it is unclear what the expectation is with DER resources going forward or what the expectation is of DER Managers and aggregators who will manage the majority of these flexible resources on behalf of their customers.

> Q3: Do you have any feedback on our description of each key driver in section 4?

Vector agrees with and repeats the Northern Energy Group's submissions on this question, which we provided input into.

5. Possible challenges and opportunities in power system operation during New Zealand's transition to net zero emissions

Is there sufficient coordination of system operation?

> Q4: What do you consider will be most helpful to increase coordination in system operation? Please provide reasons for your answer.

- We agree with the need for common standards and protocols to unlock full DER potential – however the distribution regulatory settings programme appears to be tackling only <u>some</u> of these issues e.g. consumption data, but not DER registration and visibility via Registry or otherwise. These are low-hanging fruit that can be organised quickly. The more data the industry is able to access, the more able we are to conduct trials, learn and improve the future outcomes when scale starts to become an issue.

- The more we can dynamically offer and optimise capacity on the network the more affordable whole-of-system energy costs we can achieve. Key to this is the DSO role, working alongside fellow industry parties, using digitalisation and digitisation tools to orchestrate.

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[6] EECA: https://www.eeca.govt.nz/insights/eeca-insights/hot-water-heat-pumps-in-the-home/

- The Authority should focus on what we know needs to be done e.g. much greater communication between the SO, EDB and parties operating on networks (e.g. aggregators/flexibility traders). Two examples or areas of where it breaks down when communication occurs only on one part of the system and not the whole of system (end to end), includes:

    - The Dispatch Notification enhancements introduced last year – included improved communication between the SO and flex provider(s) only, not requiring any communication with EDBs, even though the assets controlled by flex providers are connected to the distribution network. The enhancements highlighted that the SO has no visibility beyond the GXP, which would imply that distributors should also be consulted to ensure that dispatch happening beyond the GXP will not have a negative impact on the network. A consumer's experience of an outage is the same, regardless of where the system breaks.

    - Leaving coordination of flexible demand at the distribution level to EDBs and retailer aggregators with no regulatory guidance has been problematic. While the DDA provides some bare-bones guidance to distributors, the DDA is about the provision of distribution services and not the procurement of flexibility services. The DDA suggests that flexible load ought to be provided by the retailer to the distributor, to support emergency activities on the network i.e. network 'emergencies' (a subset of System Emergency Events). This use case falls within the realm of 'distribution services' which is the remit of the DDA, and such emergency response requirements should therefore be the subject of a Load Management Protocol agreed between the distributor and retailer.

    - However, no examples or definitions are provided as to what constitutes a network emergency that would require an emergency response by retailers with flexible demand. By nature, the distribution network is more exposed to weather, vegetation and human interactions than transmission network assets. There are two orders of magnitude more 'nodes' on the distribution network than the transmission network. Therefore 'emergencies' arise with more frequency on the distribution network, which is also where the coordinated behaviour of DER, even in relatively modest amounts, can have an impact on physical network assets designed on an assumption of diversity. The lack of guidance makes it difficult to agree a load management protocol under the DDA as parties, themselves, are left to define what is within the ambit of 'distribution services' and/or network 'emergencies', and what is not.

    - What is clear under clause 5.6, at least as to the intent of that clause, is that emergency management or emergency response activities must take priority over other purposes for which load might be controlled. However, we think the following further clarifications are needed in the DDA, to avoid distributors, retailers and flexibility traders getting into difficulty agreeing load management protocols that reflect the intent of the DDA:

- A clear and separate definition of ‘network emergency’, as distinct from System (or Grid) Emergencies, given the differences noted above.
- Inclusion of “network emergency” as a priority right at schedule 8, ahead of market participation which would be consistent with clause 5.6
- Clarifying that the prescription of network Operating Limits to safeguard the Network and prevent outages are within the scope of distribution services or emergency activities under the DDA. This would greatly accelerate the negotiation process for the LMP by focusing conversations on the implementation methods for adhering to network operating limits and emergencies, rather than whether or not it is reasonable for networks to expect flexible demand to adhere to network limitations. Like the definition of “System Emergency Events” Operating Limits/Envelopes act to avoid “imminent” outages and are akin to the constraints limiting generator exports and the frequency limits within which the Grid must stay to avoid black starts.

Q5: Looking at overseas jurisdictions, what developments in future system operation are relevant and useful for New Zealand. Please provide reasons for your answer.

We welcome the Authority having commissioned the EY report. It is a useful summary of key developments overseas in comparable markets. International scanning should be a core part of any regulatory change process the Authority undertakes.

Given our core interests, we focussed our attention on the material with direct relevance to DER integration and activation, and DSO, and note that it aligns broadly with our understanding. We noted the following in EY’s summary on page 13 of their report, which aligns well with our thinking and development:

> *System operators need new capabilities to manage increasingly dynamic and decentralised supply and demand. New capabilities are needed to operate power systems, both at the transmission level and increasingly at the distribution level. New capabilities identified within the jurisdictions researched include:*
>
> - *Enhanced investment planning (including better understanding where non-network solutions should be deployed in place of network investment)*
> - *Improved forecasting and modelling for dynamic power flows and intermittent supply, along with dynamic operations to respond to changing system conditions*
> - *Enhanced visibility (particularly at the low-voltage level), and data capture and sharing (e.g. between transmission and distribution operators)*
> - *Integration of flexibility services, demand response and services from DER into grid operations and planning for grid development*
> - *Streamlining and standardising the connection process for new energy resources, including DER*
> - *Improved coordination between the different electricity system actors (e.g. between TSOs and DSOs and/or across energy vectors)*

We also note that these areas are consistent with development that NEG has signalled in its positioning paper, and that ENA's Future Networks Forum is actively working on.

We did note a couple of issues with the EY report, however. Firstly, it was let down slightly by being about a year out of date. This space is moving very quickly, and it is a shame that the report was not released sooner after its completion. The developments in the UK, especially Ofgem's recent decision **not** to require separation of DSO from DNO functions, is a critical precedent in this area, and one the Authority needs to fully digest.

Secondly, the EY report lacked recognition of some of the critical differences in context between New Zealand and some of the overseas jurisdictions. As we noted in our cover letter, an example of this can be seen in different jurisdictions' choices around communications protocols to coordinate behaviour of flexible resources. Over the last decade, Australia has been managing constraints on their *low-voltage* networks from distributed solar generation by developing inverter-based standards. Australia is now looking at extending the CSIP-AUS protocol with additional components from the IEEE 2030.5 standard to enable the integration of more consumer devices.

Over the same period in the UK, DNOs and Ofgem coordinated regulator-supported innovation (370 innovation projects at a total cost of £271M were funded in RIIO-1)[7] and "flex first" network planning philosophies to build a market-based approach that initially managed constraints on the *high-voltage* assets of distribution networks. We understand that distributors began with high-voltage assets in the UK partially because DNOs designed for (and consumers are paying for) much higher levels of low-voltage capacity than in either New Zealand or Australia. Accordingly, the UK has pursued open APIs and protocols such as OpenADR that have strong market-based mechanisms built in. Ofgem and DNOs are now expanding those market-based solutions to account for the growth and "herding" caused by electrification by consumers on their low-voltage network assets. Even after a decade of implementing "flex first" efforts, it is notable that Ofgem are still testing different market structures, communications standards, and other aspects of system operation associated with demand flexibility.

This demonstrates that understanding context and allowing evolution through real-world implementations is critical to designing the operation and regulation of the sector during this transition.

Q6: Do you consider existing power system operation obligations are compatible with the uptake of DER and IBR generation? Please provide reasons for your answer.

We agree that enhanced observability and controllability of DER will be critical to the future operation of the electricity system. In New Zealand, there is some existing visibility of DER which

[7] NERA, *Innovation under the DPP: potential barriers and solutions*, Dec 2022. https://blob-static.vector.co.nz/blob/vector/media/vector-2023/nera-221220-innovation-under-the-dpp-potential-barriers-and-solutions.pdf

addresses safety risks to line workers from distributed generation injecting power on otherwise de-energised lines.

However, it is apparent that the ICP registry is limited in what it can track as DER becomes more affordable and behind-the-meter installations become more complex with interactions between smart EV chargers, smart home appliances, home batteries, and home PV systems. The recent changes the Authority made to the ICP registry[8] may provide a temporary fix to the existing challenge of accurate information for behind-the-meter DER, as noted in our response to the Authority's consultation on *Minor changes to the registry* but these are not an enduring solution.

Due to the opportunities created from more affordable DER, we are seeing aggregators emerge in New Zealand to offer consumers smart EV charging, smart hot water control, and home solar/battery systems. This matches experience from overseas, as noted in the EY report. In some cases, these aggregators are existing industry players who have the accompanying obligations to power system operation, and knowledge of how to operate in accordance with good electricity industry practice, and in other cases these aggregators currently lie outside of the "traditional" power system.

In the existing framework for electricity system operation in New Zealand, we have not identified what reasonable obligations on aggregators or DER Managers should be. Potentially this could cover two areas: first, how DER Managers interact with consumers and businesses and second, how DER Managers interact with the rest of the electricity sector – especially their host EDBs.

In addressing the first area – relationships with consumers and businesses – the Department of Energy in the US[9] and the Association for Decentralised Energy in the UK[10] have drafted recommended codes of conduct for DER aggregators. The idea of having a code of conduct is to improve consumer trust by setting standards for conduct and encouraging best practices for flexible load management. These cover topics like sales and marketing behaviour, technical due diligence obligations, contractual structures, complaint procedures, and record-keeping requirements. The Authority could review these existing efforts and consider whether there are principles to adopt in NZ that support the stated goal of encouraging uptake of DER, while also creating an obligation to record data that helps the Authority monitor the market as it evolves on behalf of consumers.

In addressing the second area, the interactions with the rest of the electricity sector, regulators and policy-makers have made progress in creating an enabling environment for DER, but there are still gaps in the framework. The focus to date has been on enabling market participation, instead of creating an environment for safe operation on, and interaction with, the system.

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[8] See: https://www.ea.govt.nz/projects/all/registry-enhancements/

[9] US Department of Energy, *DER Aggregator Code of Conduct*, https://www.energy.gov/sites/default/files/2023-11/2023-11-01%20DER%20Aggregator%20Code%20of%20Conduct%20nov%202023_optmized.pdf

[10] Association of Decentralised Energy, Voluntary FlexAssure schemes, https://www.flexassure.org/

From our perspective as an EDB, there is a lack of information (collecting and making available) for the visibility of DER type, location, size and behaviour. There is also a lack of clarity around objectives for the electricity sector participants and whether those are compatible objectives (for example if the appropriate objective for EDBs is to minimise investment required to meet load, or to maximise the ability of aggregators to sell flexibility into upstream markets, or both). At present, when participants' objectives are not compatible, significant effort is spent trying to work out what obligations or priority should be expected following 'good electricity industry practice'.

An example of this could be assessing whether an EDB should upgrade network infrastructure to enable better access to markets for DER aggregators. In this circumstance, the value that DER aggregators provide to the wholesale energy markets is not considered by an EDB when deciding between network infrastructure under the DPP regime, or pursuing an alternative option (like demand flexibility). If pursuing an alternative option, the EDB would need the confidence that DER activity would remain within the physical limitations of the existing network, which at present relies on negotiating a load management protocol or being able to justify and fund payments for flexibility services. The consequential question would be from whom should the costs of any upgrades be recovered, and how.

Q7: Do you consider we need an increased level of coordination of network planning, investment and operations across the New Zealand power system? Please provide reasons for your answer.

As noted in our cover letter, most of the focus of the Authority's paper appears to be on coordination at the grid level. We think this coordination is relatively mature; instead, coordination needs to increase across all levels of the network, and especially between the SO and EDBs, and between DER Managers and their host EDBs.

Vector otherwise supports the Northern Energy Group's submissions on this question, which we had input into.

We also repeat our comments from the Executive Summary, about the settings needed to enhance and ensure appropriate coordination.

Settings to enable smart, safe and stable DER orchestration

In addition to the coordination points above, additional key requirements that will help enable increased coordination and smart orchestration on distribution networks include:

1. The Authority working with its Council of Energy Regulators colleagues to:
   - Make EV smart-charging standards, connection to a smart system, and registration all mandatory
   - Require off-peak charging for EVs by default (as per UK)
   - Ensure that cross-cutting regulatory settings enable industry participants and provide resources to support this vision

- Improve the available DER data, and access to that data, for the whole sector

2. Empower the EDB to be the 'default' (or last resort) DER Manager on their network (as per status quo)
3. Provide EDBs with the powers to direct the response to emergency situations by the DER Managers on their networks – from grid emergencies to local, LV issues
4. Enable EDBs to avoid emergencies (referencing DDA S4.5) by ensuring distribution-level constraints (physical + power quality) are understood and adhered to by DER Managers on distribution networks. This needs:
    - A mandatory, 24/7 operating envelope at each ICP that must be adhered to by DER Managers
    - DER Managers to ensure offers into wholesale markets stay within their operating envelopes

Enabling Code is the first-best solution for these things and should be expedited.

In its absence, we are attempting to formalise 3 and 4 above in a 'load management protocol' with retailer DER Managers, as per DDA cl 5.6. However, no such mechanism exists to enable safe operation of non-retailer DER Managers (not currently industry participants to whom the Code applies) on our networks (and there is no indication that this is expected 'good electricity industry practice').

Q8: Do you think there are significant conflicts of interest for industry participants with concurrent roles in network ownership, network operation and network planning? Please provide reasons for your answer.

We have contributed to, and support, the comments in the submissions of ENA and the NEG that respond to this question.

For our part, we repeat the comments earlier in our cover letter:

We agree that the potential for conflicts to arise is real. Where we may disagree with the Authority, and likely other submitters, is in the likelihood of these conflicts leading to suboptimal outcomes for consumers, and the scale of those disbenefits.

The Authority usefully noted, in paragraphs 3.37 – 3.43, the different mechanisms / controls used to mitigate the risks of the conflict of interest between the GO and SO. These are useful precedents for the future separation of duties between the DSO and DNO component parts of an EDB. However, what was missing from the commentary was the timing of when each risk may materialise, and when the need for each intervention may become pressing. The wholesale market, and the role of the SO, have existed for nearly 30 years, but these controls have only emerged and been implemented progressively <u>over the course of those three decades</u> – some pre-emptively as concerns have arisen, some following review of specific incidents. This suggests that the introduction of controls and separation at the distribution level also needs to be an evolution, as and when concerns become material.

Further, there are already many existing controls to manage the risk of conflicts of interest at the distribution level:

- Part 4 requirements for EDBs to consider all cost-effective alternatives to traditional investment
- Arm's-length requirements in Part 6A of the Code
- Open, competitive access to DER management, defined under the DDA
- Rules governing related-party transactions
- Regulated processes and terms for connecting distributed generation in Part 6
- Competition law

We are not, suggesting, the potential concerns be ignored until issues become clear; rather, potential conflicts should be named as soon as possible, and monitored regularly, with a clear set of criteria specified ex ante for when further investigation may be warranted.

Ringfencing or separation of DSO role from DNO would be a step too far, as it can be efficient for an EDB to self-supply flex services (as we note later in this submission, with reference to expert advice received in 2022). Furthermore, late in 2023, Ofgem deliberately made the call not to require separation of DSO from DNO roles within an EDB, after careful deliberation. We recommend the Authority should dive deeply into this important precedent, as their EY report is already a year out of date.

Self-supply of network services by distributors can be efficient

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.

Although our experience of deploying NWAs has been gained largely through self-supply[11], we have gone to market for technology solutions where appropriate. Recognising the broad policy direction and intent for us to go to market for "NWAs as a service", we identified a suitable candidate investment project for a NWA and recently tested the market for such offerings. We describe the process we went through for our Warkworth project at page 31 of our submissions to the Authority on *Updating the Regulatory Settings for Distribution Networks*[12].

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[11] 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.

[12] Available online at: https://blob-static.vector.co.nz/blob/vector/media/vector-2023/vector-submission-issues-paper-updating-the-regulatory-settings-for-distribution-networks_1.pdf

In August 2022, 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". We also appended CEG's advice to our submission to the Authority on *Updating the Regulatory Settings for Distribution Networks*.

CEG report: Distributors self-supplying NWAs can be efficient

The Authority, 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.

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 calm/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 any preconceptions it has in this area. 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.

Further, 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. As noted above, there is also an established regime for monitoring related-party transactions (RTP), established rules around cost allocation between regulated and unregulated activities, and distributors all have robust procurement policies.

In the process of developing this work further, it would be worth the Authority highlighting to the Commerce Commission any particular deficiencies in or concerns they have with the Commerce Commissions 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.

Given the recent introduction of 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 Commerce Commission;

2. if an extension of the arm's length rules is 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?

Q9: Do you have any further views on whether this is a good time for the Authority to assess future system operation in New Zealand and whether there are other challenges or opportunities that we have not covered adequately in this paper? Please provide reasons for your answer.

We raise issues of concern below:

a. A successful and equitable energy transition to the decarbonised future we seek, depends as much upon industry alignment as it does upon policy and regulatory alignment or coordination. For this reason, Vector has previously called for the creation of a Ministry of Energy to ensure better alignment across policy and regulatory settings for the energy sector.

    The various workstreams that sit across different teams at the Electricity Authority alone, such as the FSO/FSR workstream, the Distribution Pricing Reform workstream, the Distribution Regulatory Settings workstreams, and related Code review workstreams (such as the recent review of the DDA and the upcoming review of Part 6 Code), are illustrative of this point. All of the issues and complexities that sit across these workstreams are highly interconnected. They must therefore be considered methodically – in terms of timing and prioritisation, and holistically – across the Electricity Authority and across co-regulators. It is not enough to have coordination across the industry sector alone. There must also be coordination across the three key regulators of the energy sector. How this is planned or proposed has not been made clear.

b. Relatedly, distributors currently hold all the responsibility for maintaining reliability on their networks based on the default price quality path requirements (SAIDI/SAIFI). Going forward, a larger number of participants or DER Managers will have influence over network reliability, so it will be appropriate for the responsibility of network reliability to be shared with larger flexibility traders. We understand the Commission may be considering whether shared responsibility ought to apply in some instances, via carve-outs to SAIDI. This further illustrates our point above about the need for coordination among regulators.

c. As Vector has previously submitted, financeability or investability must be a key area of focus. Without the appropriate regulatory settings in place that support the investments critically needed for distribution and transmission networks and capability, the future power system we need to deliver whole of system benefits, decarbonisation targets and reliable, resilient power will be severely compromised.

d. Finally, although improved sector coordination depends upon enhanced and better data flows, it is important that access to data is on reasonable commercial terms. It is important that commercial access to data be unfettered, and barriers should be swiftly dealt with. However, such access should be not costless, on the basis that it will otherwise undermine ongoing investment and service evolution by the metering companies who must invest to collect, curate and cleanse the metering data for provision to interested participants, and develop and market further value-added services.

Closing Comments:

We appreciate the opportunity to respond to this consultation and are available to answer any questions regarding our submission.

Kind regards,

James Tipping
GM Market Strategy / Regulation

Excerpt from Northern Energy Group – DSO Evolution – Slide 11, February 2024

https://www.linkedin.com/feed/update/urn:li:activity:7165419774091481088/