SUBMISSION ON UPDATING THE REGULATORY SETTINGS FOR DISTRIBUTION NETWORKS

vector

Executive summary

Vector agrees that distributed energy resources (DER) offer significant potential benefits to electricity consumers, and that electricity distributors will play a key role in optimising these benefits and enabling a transition to a low-carbon future.

While the electrification of transportation and heat are expected to have significant impacts on low voltage distribution networks, the exact characteristics of those impacts are still unknown. This uncertainty from DER installed at homes and businesses presents both a challenge and an opportunity for distribution businesses.

The Climate Change Commission notes that electrification "*will need to be accompanied by expanding infrastructure for transmission and distribution",*[1] and Vector is working hard alongside other New Zealand distributors to explore the potential of DER to deliver an affordable and reliable transition alongside widespread electrification. Some examples of the work we've done include:

- Investigating a broad range of services from DER, with an effort to reduce costs and improve reliability. These services include hot water load control, batteries, smart electric vehicle (EV) chargers, and behavioural demand response; and
- Investing to improve network visibility and management so our network can host DER provided by a range of parties and integrate DER in a way that maximises overall benefits.

International experience has shown that the value of DER to distribution networks will be location and time specific for each distribution business, To effectively assess the operational impacts and economic viability of using DER, distributors must have increased visibility of their low-voltage (LV) systems and assets, confidence in DER performance expectations, and reliable forecasts of future consumer loads on their networks.

Given that flexibility services are still in the early stages of development, we advocate establishing a series of workshops to break out of the industry silos and develop a 'no regrets' pathway aligning the whole electricity sector to optimise long-term consumer value from DER. We believe achieving the Electricity Authority's (the Authority) stated objective of deploying an efficient and integrated mix of network and non-network alternatives rather than simply aiming to increase the use of flexibility services will best deliver long-term consumer value.

Acknowledging that the problems and remedies of DER integration are interdependent means that we need an ordered response that recognises that it is unclear what the market will look like in the future. Reforms need to be sequenced to progress the visibility, integration, incentives, enablement, and uptake of flexibility services. This reform pathway should drive consumer value from new DER assets and services – rather than expand a regulatory approach that was designed around a different set of risks and objectives or a predetermined view of how the market, new technologies or business models may evolve.

In Vector's view, a way forward for New Zealand's electricity sector involves:

- Mandating 'smart' and safe EV charging standards;
- Improving visibility of the LV distribution network;
- Improving visibility into DER deployments and how they are affecting or may affect distribution networks and their service obligations; and
- Refining incentives that encourage distributors to optimally use and support flexibility services and invest in digitalisation capabilities.

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[1] Climate Change Commission, 31 May 2021, Ināia tonu nei: a low emissions future for Aotearoa, p112. Emphasis added.

It is critical that regulatory frameworks as well as industry and commercial arrangements continue to evolve to manage the risks and harness the opportunities from the complex interactions between electricity network operations, new technologies, and markets.

Vector is committed to continue working with the Authority, the Commerce Commission, other regulators, consumers, and industry participants to ensure that DER plays an important role in energy supply and network transformation – and in *creating a new energy future*.

28 September 2021

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Introduction

This is Vector Limited's (Vector) submission on the Electricity Authority's (the Authority) discussion paper on *Updating the Regulatory Settings for Distribution Networks* (the Discussion Paper), dated July 2021.

We appreciate the Authority's virtual engagements with stakeholders via Zoom calls during the consultation period. We are happy to further engage with the Authority and other industry participants following this submission process to support evidence-based regulatory decisions.

This submission has two parts.

- Part 1 provides Vector's high-level commentary on DER integration and flexibility services and proposes 'in principle' approaches and/or solutions to the issues identified by the Authority.
- Part 2 sets out our feedback on the above issues and responses to the Authority's consultation questions, by theme.

We are happy to discuss any aspects of this submission with the Authority. Please contact Matt Smith (Policy Advisor, Strategic Planning) at Matt.Smith@vector.co.nz or 09 978 7812 in the first instance.

No part of this submission is confidential, and we are happy for the Authority to publish it in its entirety.

Vector broadly supports the submissions of Vector Metering, Vector Technology Services, the Electricity Networks Association (ENA), the Northern Energy Group (NEG), and the Sustainable Electricity Association of New Zealand (SEANZ).

Vector's Symphony strategy emphasises collaboration with other parties and puts customers at the heart of our decision making.

Part 1: Developing the appropriate regulatory settings for distribution networks

Electricity distributors and their customers have a vital role to play in the transformation of the energy sector and New Zealand's transition to a net zero emissions economy by 2050. Through our electricity distribution network in Auckland, we are rising to the challenge of providing new energy solutions that promote energy efficiency and the use of renewable DER. This will benefit all New Zealanders, not just Aucklanders, and move us all towards an affordable low-carbon world.

Part 1 of this submission sets out Vector's high-level views on the type of regulatory settings we believe would enable distributors to achieve the above objectives and deliver outcomes that are in the long-term benefit of consumers.

Distributors can help optimise the value of flexibility services for consumers

Vector agrees that flexibility services could offer significant potential benefits to New Zealand. Distribution provides an important component in consumers' delivered energy services, both today and in the future. The evolution of DER, both technology and cost are increasing the range of options open to all consumers. We support the Authority's objective that distribution services should be delivered using an efficient mix of network and non-network solutions. In some circumstances, flexibility services have the potential to be more cost-efficient, yet network operators must also consider the physical risks to the network, and supply reliability and power quality risks for customers.

Given the level of uncertainty around DER and flexibility services, New Zealand would benefit from focussed efforts to gain a better understanding of the interactions between DER and low voltage (LV) network operations before significant new regulatory obligations are considered. We advocate planning a 'no regrets' pathway that seeks to optimise the consumer value of delivered energy services[2], including flexibility services while retaining optionality to adapt to an uncertain and evolving future. The approach would initially focus on improving low voltage network visibility and the availability of information to efficiently integrate DER, which would be supported by targeted reforms to provide the right incentives and reduce the transaction costs for the use of flexibility services.

We are actively supporting flexibility services and DER

Vector is currently taking a range of actions to explore the potential for flexibility services and ways to increase their use. We are already using and trialling a broad range of flexibility services to reduce costs and improve reliability, e.g. load control, peak time rebates, grid-scale batteries, and smart EV charging.

We have an obligation to serve our customers electricity when it is needed at an appropriate power quality with minimal outages and with our revenue determined by the Commerce Commission. Through our planning processes, we ensure that the network is designed and maintained such that it does not place the general public or utility workers at risk. To that end, we are also investing to improve network visibility and management so that our network can host DER provided by a range of parties and integrate it in a way that is safe, reliable, and cost efficient.

For instance:

1. **Symphony strategy** – Our Symphony strategy is reflected in our 2021 Asset Management Plan (AMP). Through Symphony, we intend to transform the traditional poles and wires of the electricity networks serving the Auckland region into an

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[2] Delivered energy services in this context are viewed from the consumers perspective and can be delivered both behind and upstream of the meter or connection point.

intelligent energy system where customers have more choice and control. Our strategy calls for a system which reduces peak loads, helps manage demand profiles, and provides customers with choice and control, while maintaining service standards.

2. **DER-related investments** – Our 2021 AMP includes significant planned investment to support this vision, including: a) developing a Distributed Energy Resources Management System (DERMS) platform – a highly intelligent software system that enables us to integrate a range of DER assets connected by any party to our traditional network infrastructure to our network management systems, b) an Advanced Distribution Management System (ADMS), and c) investment in cyber-security.

3. **New Energy Platform (NEP)** – This was created through our strategic alliance with Amazon Web Services (AWS). Through this alliance, Vector and AWS will leverage the breadth and depth of AWS services (including Internet of Things, analytics, machine learning and infrastructure services) with Vector's energy industry knowledge, plus the joint engineering capability of both organisations.

4. **Strategic collaboration with X, the moonshot factory (formerly Google [x])** – Vector and X are working together on network virtualisation and simulation technology[3]. This is part of our shared vision to reimagine the design, management and operation of electricity networks; get ahead of increasing demands for clean energy; and transform the network to support decarbonisation. We will deploy solutions developed through this collaboration initially in the Auckland region but plan to make them available more broadly, given the urgent global need to decarbonise electricity networks.

Vector is 75.1% owned by its customers through Entrust. This creates a strong incentive to act in the overall best interests of both our customers and shareholders and provides additional insights into how to best serve those interests.

Regulatory focus should be on reducing barriers and improving incentives

The Authority should consider actions that reduce barriers and improve incentives for distributors to use flexibility services as non-network alternatives, while at the same time ensuring that any such actions are coordinated across regulators.

In our view, the Authority and other relevant bodies such as the Commerce Commission should focus on:

1. Improving visibility across distribution networks and DER with the efficient deployment of solutions at system, resource and provider levels – this can help enable the market for flexibility services and is an important precondition for other actions;

2. Reviewing and refining incentives for distributors to use flexibility services and increase their DER hosting capacity – this should be an important part of the Commerce Commission's upcoming Input Methodologies review; and

3. Minimising transaction costs for the use of flexibility services as non-network alternatives – this could make it easier for flexibility providers to offer non-network solutions to distributors.

Given that flexibility services are still in the very early stages of development, the Authority should take <u>an approach that retains flexibility for a range of different business models to emerge</u>. This is an area where innovation should be encouraged, with parties trialling a range of different models to determine which ones best serve consumers' needs. The value of DER is location and time specific; there is no 'standard' for a flexibility service. Imposing that will frustrate a fledgling market.

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[3] https://www.vector.co.nz/news/vector-collaborates-with-x

Though Vector does not envisage its regulated distribution business owning or operating large amounts of flexibility assets, regulatory arrangements should not preclude that option at this stage. There is currently no evidence justifying such a restriction – and the Commerce Commission has previously concluded that imposing these types of restrictions would reduce efficiency and increase costs for consumers[4]. Existing regulatory arrangements including cost allocation methodologies, related party transaction rules and significant information disclosure requirements create a level playing field and address the risks of cross-subsidisation or discrimination.

The rest of this chapter focuses on the principles that should guide how the Authority assesses what changes to the regulatory settings, if any, are appropriate.

Regulatory principles can guide the Authority's approach to this issue

The Authority's approach to the issue of equal access to flexibility services will obviously be guided by its objective under the Electricity Industry Act (the Act): *to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers*.

The Authority's approach must recognise that how competition is advanced for flexibility services can affect both the reliable and efficient operation of the network in either positive or negative ways. This means that it must be informed by timely and accurate data on the nature, scale, and time horizons within which flexibility services can benefit consumers of each EDB, as well as the costs of implementing different deployment, integration, and cost recovery models.

Enabling Smart EV Charging

Some actions to unlock future flexibility and demand response value – for example, the uptake of smart and safe EV chargers – would require changes to the Electricity Industry Act. These could consist of provisions which define who is or is not an industry participant for the purposes of the Code's application. We support this as an option to ensure the installation of optimised charging infrastructure and avoid locking consumers out of the future benefits of dynamic, digitally enabled demand management. We acknowledge that amendments to the Act that are currently being progressed are outside of the Authority's jurisdiction. This is an area where clear and proactive 'no regrets' action can be taken to ensure the potential benefits of smart EV charging are realised for both individual EV owners and all electricity consumers.

There is also a health and safety imperative to mandated regulation of EV chargers – with many consumers in New Zealand and overseas favouring the use of standard sockets for charging, in the absence of such regulation.[5]

There is considerable overlap between the above issues and the Commerce Commission's functions. Several of the options proposed by the Authority in the Discussion Paper would or may need to be implemented by the Commission under existing arrangements.

The Authority should therefore also consider the purpose of Part 4 of the Commerce Act – which is consistent with the Authority's objectives but provides more specific guidance in several areas:

> *The purpose of this Part is to promote the long-term benefit of consumers in markets referred to in section 52 by promoting outcomes that are consistent with outcomes produced in competitive markets such that suppliers of regulated goods or services—*

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[4] Commerce Commission, *Input methodologies review decisions: Topic paper 3: The future impact of emerging technologies in the energy sector*, 20 December 2016, para. 190–213.

[5] For further information on this, please refer to the Northern Energy Group submission responding to the Ministry of Transport's Hikina te Kohupara.

(a) have incentives to innovate and to invest, including in replacement, upgraded, and new assets; and

(b) have incentives to improve efficiency and provide services at a quality that reflects consumer demands; and

(c) share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices; and

(d) are limited in their ability to extract excessive profits.

The Authority should also be mindful of the requirements of sections 52T and 54Q of the Commerce Act[6] and the Commission's guidance in its 2016 Input Methodologies determinations that: [7]

> *Consumers of regulated services will be the ultimate beneficiaries of the economies of scope realised by regulated suppliers from engaging in new activities...This IM is intended to ensure that consumers of regulated services benefit over time from any efficiency gains achieved by EDBs supplying regulated and unregulated services together, consistent with s 52A(1)(c). As a consequence of these efficiency improvements, consumers of unregulated services also benefit.*

We also recommend that the Authority's approach be guided by principles of best practice regulation, including the New Zealand Treasury's *Government Expectations for Good Regulatory Practice* and the Organisation of Economic Cooperation and Development's guiding principles for regulatory quality and performance. Consistent with these principles, the Authority should:

1. Begin by clearly identifying the objectives and the nature and underlying causes of the problems that need to be addressed to achieve those objectives.

2. Then assess the evidence of the existence and extent of these problem and analyse whether existing regulatory arrangements adequately address them or not.

3. Only propose new regulatory interventions if there is evidence of a material problem that is not addressed by current arrangements and only to the extent needed to address that problem. Any new regulatory requirements should be well-aligned with existing arrangements and not create inconsistent or duplicative requirements.

4. Recognise that regulatory intervention is costly and could undermine efficient and socially optimal outcomes due to unintended consequences.

The Discussion Paper currently seems to jump to potential solutions without clearly identifying evidence of a material problem that is not adequately addressed by current regulatory arrangements.

The Authority should also recognise that the potential issues raised in the Discussion Paper are not independent of each other, and the potential remedies should not be separately assessed in the way the Paper currently does. Rather than a siloed approach, the future regulatory regime should seek to achieve a whole of systems approach to strengthen the integration of DER assets and flexibility services for the long-term benefit of consumers.

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[6] Section 52T provides that the Commission's input methodologies must not unduly deter investment by a supplier of regulated goods or services in the provision of other goods or services. Section 54Q provides that the Commission must promote incentives, and must avoid imposing disincentives, for suppliers of electricity lines services to invest in energy efficiency and demand side management, and to reduce energy losses.

[7] Commerce Commission, *Input Methodologies review decisions – Topic paper 3: The future impact of emerging technologies in the energy sector*, pp.65,68.

Acknowledging that the problems and remedies are interdependent means that we need an ordered response that recognises that the future evolution of the market is uncertain. Reforms need to be sequenced to progress the visibility, integration, incentives, enablement, and uptake of flexibility services. This reform pathway should drive consumer value from new DER assets and services – rather than expand a regulatory approach that was designed around a different set of risks and objectives or a predetermined view of how the market, new technologies or business models may evolve. The opportunity envelope for all current and potential suppliers and participants should be maximised at this stage of the electrification revolution, rather than constrained through assumptions about potential problems.

We also recommend that the Authority learn from – but be cautious – in applying examples from much larger overseas markets. The Discussion Paper draws on several examples of Australian and UK regulatory arrangements that may not be suitable in New Zealand. Australian and UK electricity distributors are much larger and more homogenous than New Zealand distributors, and DER uptake (particularly solar PV) in Australia is also far greater.

A certain level of scale in a region is required for effective competition to emerge and for the costs of new regulations to outweigh the potential benefits. For comparison of NZ to other jurisdictions:

1. New Zealand has installed 163 MW of solar PV. Australia has installed over 16,000 MW. This difference is due to government subsidies, feed-in tariffs, great solar irradiance, and more than 4 times as many houses (on which to place PV) in Australia – not the market settings for equal access.

2. The total combined Regulatory Asset Bases (RABs) of all 29 New Zealand electricity distribution businesses is around NZ$13 billion, which is about the same as the RAB for AusGrid – the electricity distributor for Sydney. New Zealand distributors serve a combined 5 million people, while the UK distributor UK Power Networks serves 18 million people.

New Zealand is not experiencing the same network constraints and technical challenges that arise in areas with very high penetration of DER as seen in parts of Australia. High levels of DER uptake have resulted in a range of power quality, reliability, and system security risks that have required regulatory solutions that may not be relevant for New Zealand distribution networks.

New Zealand also has a different context given that many distributors – including Vector – are fully or majority owned by consumer trusts and so have stronger incentives to act in the overall best interests of their customers. New Zealand has a long history of many distributors operating other businesses in a wide range of competitive markets with no evidence that doing so has lessened competition, and in some areas it has clearly improved competition and efficiency.

In our role as a distributor, we have a responsibility to act in the best interest of all customers, without favouring one customer class over another. Assessing the trade-offs for network customer benefits against the benefits that individuals wish to gain from their DER is an ongoing challenge. An example might be expectations that distributors configure the network to enable distributed generation customers more opportunity to inject power that potentially reduces wholesale electricity costs for all customers, but at a cost to other consumers. However, a distributor must evaluate any additional costs or risks to maintaining reliability and quality of service to other customers on the network as well.

Potential underlying problems do not necessarily warrant regulatory solutions

The Discussion Paper states that:

> *The objective is for distribution services to be delivered using an efficient mix of network and non-network alternatives... Using flexibility services can now be a more*

efficient solution in some cases... delivering the same results for a lower cost or delivering better results for the same cost.

We agree with that objective. However, the Discussion Paper does not provide evidence of underlying problems that suggest the current regulatory regime would not deliver on this objective.

The options for solutions set out in the Discussion Paper appear to be based on assumptions that:

1. The current use of flexibility services by distributors is less than an efficient level due to limited competition in flexibility markets, including barriers to entry and an uneven playing field;

2. Distributors favour network solutions or their own DER over competitively provided flexibility services even when competitive solutions are more efficient; and

3. Increased competition for flexibility services will on its own benefit consumers, even if it limits distributors' ability to achieve economies of scale and scope or solve coordination challenges by owning and operating DER.

We do not agree with these assumptions.

Several of the options in the Discussion Paper also seem to aim to simply encourage more use of flexibility services, rather than <u>encouraging the stated objective of an efficient mix of network and non-network alternatives</u>.

We recommend that the Authority clearly identify the underlying problems it is seeking to resolve and assess the evidence of the existence and materiality of those harms.

It appears to us that the potential harms that could undermine the achievement of the Authority's objectives can be summarised as:

1. **Inefficient incentives** – The incentives for distributors to purchase flexibility services are insufficient and should be reviewed. We suggest that the Authority or Commerce Commission analyse whether this arises due to an imbalance in capex and opex incentives under the Default Price-Quality Path (DPP) regime, limited funding for innovation and digitalisation under the current DPP, or incentives to favour more reliable and proven network solutions due to the DPP's quality standards and quality incentive mechanisms.

2. **Transaction costs** – Due to the small size of the current market for flexibility services and the uncertainty associated with some of those services, the transaction costs to distributors and flexibility service providers can mean that flexibility services are not currently a cost-effective solution. The Authority should consider the size and causes of these transaction costs. Revising regulatory incentive structures and some of the measures proposed in chapters 6 and 7 of the Discussion Paper could potentially reduce these costs, but the Authority needs to be careful not to impose even greater regulatory compliance costs or barriers that stifle innovation in the process.

3. **Lack of information** – The information issues discussed in Chapter 4 of the Discussion Paper are also a key issue that limits the use of flexibility services and non-network alternatives. Distributors currently have limited visibility of their LV networks or the DER connected to their networks. Improving information in a range of areas (e.g. EV registrations, heat pump installations, smart meter data, etc) would help define the opportunity for and grow the market for flexibility services. An underlying cause of limited network visibility are the provisions of the current DPP regime failing to fully recognise the long-term benefits of the digital and data transformation required and results in incremental spending above prescribed allowances incurring a penalty which has delayed all EDBs' ability to improve access to information.

4. **Uneven playing field** – The Authority assumes there is a risk of cross-subsidisation or discrimination in favour of the distribution business or a related business that reduces competition in the market for flexibility services. But the Authority does not provide any evidence of any such outcomes occurring and does not discuss the extensive existing regulatory arrangements that protect against this risk, some of which are currently under review as part of the Electricity Industry Amendment Bill. We consider that the existing regulatory requirements adequately address this potential issue and the Authority should focus on the untreated issues above rather than implementing unnecessary and costly mechanisms to address a risk that is already dealt with by other requirements.

Existing regulatory mechanisms can address potential problems

Many of these potential problems are already addressed by the current regulatory regime and other arrangements Vector has put in place.

In particular, the potential concerns around an uneven playing field and the risk of cross-subsidisation or discrimination are fully dealt with by the following regulatory arrangements:

1. **The cost allocation requirements under the input methodologies (IMs)** - These arrangements prevent distributors from obtaining an unfair competitive advantage over competitive providers in any service market by cross-subsidising between regulated and unregulated services. As noted above, these requirements also ensure that the costs and revenues associated with the provision of unregulated services are allocated in a way that reduces prices for consumers of both the regulated distribution service and the unregulated services. These arrangements were extensively reviewed by the Commerce Commission in 2016 as part of its work on emerging technologies. The Commission could review its cost allocation arrangements again in its upcoming IMs review and consider if any changes are needed. There is no evidence put forward of any risks of cross-subsidisation or discrimination that warrant additional regulation by the Authority.

2. **The related party transaction rules in the IMs** - The IMs contain a series of requirements regarding related party transactions and arms-length valuation rules that ensure a level playing field and remove incentives for a distributor to purchase flexibility services from a related party rather than a competitive supplier. These rules include disclosure requirements and reports by auditors and independent appraisers. The Commerce Commission completed an extensive review of these requirements in 2018.

3. **The IM requirements to address non-network alternatives in the AMP** - The IMs require distributors to disclose in their annual AMPs each planned asset replacement and renewal project and programme, a description of and the rationale for the projects and programmes, and an overview of any network and non-network alternatives considered and the basis for selecting the preferred solution. This ensures that distributors consider non-network alternatives where they may be more efficient than traditional network solutions.

4. **The Electricity Industry Act's requirements for the separation of distribution from generation and retailing** - Part 3 of the Act prohibits distributors from being involved in certain types of generation where doing so may create incentives or opportunities to inhibit competition.

5. **The Electricity Industry Participation Code's (the Code) requirements for embedded generation connection** - These provisions ensure that distributors do not favour DER owned by them or their related entities in the connection process.

Incentives for non-network alternatives are also addressed in the IMs and the DPP determination, including:

1. Capex and opex incremental rolling incentive schemes and the quality incentive scheme which incentivise distributors to adopt the most efficient solutions and reduce costs without compromising quality; and

2. An innovation project allowance which allows distributors to apply for an allowance for certain types of innovation projects that seek to reduce costs and/or improve quality of supply for consumers

However, these incentive schemes and allowances are relatively low powered compared with overseas examples. As discussed below, there would be value in the Authority or the Commerce Commission considering whether there would be benefit in improved incentives for non-network alternatives.

There are appropriate options the Authority could consider

Based on the above description of the potential problems that could hinder the efficient use of flexibility services and the extent to which those problems are already addressed by current regulatory requirements, we recommend that the Authority focus its work on the following three issues:

1. Improving visibility of distribution networks and DER;

2. Incentives for distributors to use flexibility services and increase their DER hosting capacity; and

3. Minimising transaction costs for the use of flexibility services as non-network alternatives.

Each of these issues is discussed below.

Issue 1: The benefits of starting by improving information

Chapter 4 of the Discussion Paper correctly identifies that distributors need better information regarding their low-voltage networks to enable them to make efficient investment decisions and integrate higher penetrations of DER. Once distributors have that improved visibility, they can provide flexibility providers with access to information on network congestion, hosting capacity, and other network information so they can maximise the value of flexibility services.

We consider that improving information is a critical first step that can help grow the market for flexibility services by addressing current information barriers to the efficient use of non-network alternatives by distributors and increasing the use and value of flexibility services.

For Vector, these include data analytics, distributed energy solutions, and the digitalisation of the network. Through making these investments now, we believe we can improve our planning processes to make data-led decisions around future network and non-network solutions.

Improved data can also help the Authority assess the scale, scope, and time horizons of the potential DER flexibility market and how that varies across different distribution areas. This information can help:

1. Inform and assess whether distributors are already efficiently using DER flexibility services;

2. Identify the types of flexibility services and locations where increased use could be made of flexibility services to address network issues; and

3. Inform what DER services are most likely to be viable and of the most value in the short, medium, and long term.

We recommend that the Authority consider a range of measures to improve different aspects of information. We suggest that it would be useful to break these information requirements down into three different types of visibility:

1. **System visibility** - enabling distributors to identify and measure LV network constraints and DER hosting capacity (and recover the costs of doing so). This will require investment by distributors to improve the visibility of their LV networks, as we currently have very limited visibility of our LV network and the DER connected to it. Once that network visibility has been improved, there would also be value in providing information on network capacity and constraints to market participants, including flexibility service providers.

2. **Resource visibility** - enabling distributors and the relevant market participants to have improved visibility of the location and key characteristics of DER resources. We recommend a review of the ICP registry to extend its capability to identify DER installations at ICPs. The information needs may be similar to the Asset Capability Statements currently required by the System Operator for any generators or aggregators with greater than 1MW of generation and the DER Register maintained by the Australian Energy Market Operator (AEMO). This would improve engagement between distributors and the System Operator and provide additional data to support system security planning at regional and national levels.

3. **Provider visibility** - making it easier for distributors to identify potential DER flexibility providers who they can notify of opportunities for non-network solutions, as discussed below.

These improvements in visibility will require additional investment by distributors and other bodies. Distributors will need mechanisms to obtain funding to increase visibility of their LV networks and DER connected to their networks. Potential refinements to the economic regulation regime to address this issue are discussed in the incentives section below.

Issue 2: Potential options for reducing transaction costs

Actions that may help grow the efficient use of flexibility services as non-network alternatives by reducing transaction costs could include:

1. **Provider visibility** - There may be value in making it easier for distributors to identify potential DER flexibility providers who they can notify of potential opportunities for non-network solutions, and easier for flexibility providers to obtain information about services being sought by distributors. A centralised system may be the most efficient mechanism for doing so, e.g. the Authority or the Ministry of Business, Innovation & Employment (MBIE) operating a website (or a page on their website) where potential flexibility providers could register their interest in being notified by distributors of these opportunities. Alternatively, each distributor could operate its own register like the requirements on electricity distributors in Australia to establish a facility for parties to register their interest in being notified of network developments.

2. **Reporting on the use of flexibility services in AMPs** - As noted above, distributors are already required to disclose in their annual AMPs an overview of any network and non-network alternatives considered and the basis for selecting the preferred solution for each asset renewal or replacement project. As the potential to use flexibility services increases, there could be value in distributors providing more guidance in their AMPs on how they are considering non-network alternatives. We recommend that any expanded obligations in this area should only occur after there is sufficient evidence identifying the types of investments where a non-network solution is more likely to be

viable, rather than applying to all asset renewal or replacement projects which would likely add extra compliance costs for little benefit.

3. **Engagements with flexibility providers** - There may be value in distributors scaling up how they engage with flexibility providers and being clearer about the circumstances in which they will seek proposals for non-network solutions and what information they expect to receive as part of such a proposal. This could occur through industry workshops detailing the practical constraints that distributors are facing as well discussions around the types of solutions that flexibility providers are able to offer. Through these open discussions a better understanding of the scope for flexibility services for all parties can be obtained.

4. **Standardised non-price terms for operating agreements** - There could be value in the Discussion Paper's proposal of developing template operating agreements (only for non-price terms). This could reduce transaction costs, address any perceived concerns about the potential for discriminatory access terms, and potentially improve interoperability across distributors, however, this should be pursued in collaboration with all relevant parties to ensure that the outcome of this action addresses a real issue.

Issue 3: Potential options for improving incentives

The Authority will be aware that the Commerce Commission will start its next review of the EDB Input Methodologies shortly – which provides an important opportunity to ensure that distributors face appropriate incentives to efficiently use and support flexibility services.

As discussed above, the current IMs and DPP arrangements include several measures aimed at incentivising distributors to use non-network alternatives. However, compared with overseas examples, those incentives are relatively low powered. There is less certainty about distributors' ability to recover the costs of the additional investment needed to improve LV network visibility and integrate increasing amounts of DER.

Issues that the Commerce Commission could consider in relation to improving incentives should include:

1. **Recovery of costs of improving visibility and integrating DER** - Is there a need to implement additional measures to clarify and build confidence in how the DPP framework enables distributors to recover the efficient costs of investment to integrate DER? The nature of the DPP regime makes it challenging for distributors to recover significant 'step changes' in expenditure (e.g. no step change in allowances for cybersecurity costs or data acquisition costs in DPP3 for any EDB) to meet new obligations or government and community expectations, for example, where significant expenditure is required to improve LV visibility and connect increased amounts of DER. This expenditure may increase network costs but reduce total system costs, for example, by reducing wholesale costs if more DER can be connected and dispatched. The Australian Energy Regulator (AER) has recently published several guidance documents on how it will assess DER integration expenditure, where expenditures are viewed within the context of long term DER integration strategies and is beginning to consider the whole-of-sector benefits of DER integration.

2. **Calibrating incentives for capex and opex trade-offs** - Is there a need to consider improved incentives for efficient expenditure on non-network alternatives and ensure that the regulatory regime does not favour capex over opex? This is an issue that many overseas regulators have grappled with recently and adopted a range of incentive schemes to address. For example, the AER has developed a Demand Management Incentive Scheme that provides incentives for distributors to undertake efficient expenditure on non-network options related to demand management.

3. **Funding for innovation** - Is there a need for improved funding for network innovation? The Discussion Paper states that distributors may favour more reliable and proven

network solutions over innovative non-network solutions using flexibility services. Many overseas regulators have recognised that the CPI-X style of incentive regulation used in the DPP regime results in low levels of expenditure on innovation and frequently needs significant and targeted incentives or funds. A review of the application of CPI-X regulations could be undertaken to ensure that the range of permissible investment categories are more flexible and can easily adapt to changes in policy and customer expectations.

Overseas regulators have been more proactive in incentivising innovation that could lead to long-term reductions in total system costs.

4. **Quality requirements and incentive schemes** - How do the DPP's quality requirements impact incentives for the efficient use of flexibility services? The Discussion Paper notes that some of the problems identified by the Authority may come from distributors not having evidence that flexibility services can provide the necessary level of network reliability. Distributors are subject to quality standards and a quality incentive adjustment under the DPP, which impose strong incentives and financial penalties on distributors to maintain or improve reliability. These arrangements could disincentivise the use of flexibility services if distributors cannot be confident that they will be as reliable as network solutions.

   If the Authority wants to incentivise distributors to adopt innovative non-network solutions using flexibility services, then there may be value in reviewing the impact of these incentives. For example, should the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) measures exclude outages that arise where the distributor contracts for the provision of a flexibility service but that service is not provided or does not function as expected?

5. **Guidance materials for smaller distributors** - The Discussion Paper states that distributors may not understand the current incentives. That is unlikely to be the case – but if the Authority considers that it is a risk for some smaller distributors, then the Commerce Commission should consider whether additional guidance materials would assist. The Authority should not add new regulatory obligations to address matters that are more efficiently addressed by another regulator's incentive arrangements simply because of an unproven assertion that some distributors may not understand those incentives.

The Authority's proposed options for 'significant issues' are not necessary and could harm consumers

The Authority's proposed options to address "significant issues" are not justified by evidence of a material problem that is not adequately addressed by current regulatory arrangements.

Restrictions on distributors owning or operating DER

The Authority has not presented any evidence of competition concerns that would justify restrictions on distributors owning or operating DER. As discussed above, the potential risks in relation to competition for flexibility services are already addressed by a range of regulatory requirements.

The Commerce Commission has stated that allowing distributors to own and operate flexibility services, subject to the existing regulatory requirements including cost allocation, improves efficiency and reduces prices for consumers. The Commission considered the future impact of emerging technologies in detail in 2016 as part of its review of the IMs. As part of that work, it expressly considered equal access issues and rejected proposals for ring-fencing style requirements or restrictions on distributors including certain types of assets in their RAB.

The Commerce Commission concluded that these proposals would lead to 'costs and added complexity that are more certain than the benefits it could deliver to consumers' and that:[8]

> *…it is currently unclear to us that restrictions on EDB ownership and operation of certain emerging technologies would benefit consumers of the regulated service more than the updated cost allocation IM, although we note it is possible it (or some other form of business separation) could. The requirement of arms-length transactions risks undermining the incentive on EDBs to improve efficiency through economies of scope, consistent with s 52A(1)(b). In addition, the likely higher transaction costs associated with arms-length transactions is one important (and growing) factor that could cause this.*

The Commerce Commission concluded that its approach to revenue regulation and cost allocation would deliver a better outcome for consumers:[9]

> *By capping revenues, EDBs are incentivised to find more cost-effective ways of delivering the regulated service.*
>
> *Contact raised a concern that EDBs may not have incentives to realise the full value of investments, to the detriment of consumers. . . We do not see why an EDB would not seek to derive the full benefit from their investments, regardless of whether they are used in the provision of the regulated or the unregulated service. They have an incentive to do so, and consumers of both regulated and unregulated services benefit as a result, since the costs of the investment are allocated to both services.*

Restrictions on distributors owning or operating DER would be a major intervention in the market that could have significant costs, including the loss of economies of scale and scope referred to by the Commission, increased costs of coordination, potential impacts on reliability, and significant implementation costs.

The Discussion Paper suggests that this option could go even further and prevent distributors owning or operating DER through subsidiary companies and requiring them to sell any DER they own. Such an approach would go well beyond ring-fencing arrangements that have been implemented in other jurisdictions such as Australia – which require separate legal entities but do not require separate ownership and divestment of existing subsidiaries. There is no evidence of a problem justifying such an extreme solution, particularly given:

1. Many distributors, including Vector, are fully or majority owned by consumer trusts and so have stronger incentives to act in the overall best interests of their customers;

2. Electricity distributors have a long history of having related companies that operate in other competitive markets with no competition concerns; and

3. Electricity distributors are already subject to significant information disclosure and associated rules.

Recent examples in Australia have highlighted the potential loss of consumer benefits from restrictions on the activities of distribution businesses, particular their ability to innovate and trial new services with their customers.

Several distribution businesses in Australia are currently running grid-scale 'community battery' trials to explore the potential of storage devices for network and other purposes. However, their ability to do so is limited by ring-fencing rules. To overcome the current ring-fencing restrictions, several distributors have had to apply to the AER for ring-fencing waivers.

[8] Commerce Commission, *Input Methodologies review decisions – Topic paper 3*, 20 December 2016, pp.67–68.

[9] Commerce Commission, *Input Methodologies review decisions – Topic paper 3*, 20 December 2016, p.77.

This includes United Energy (UE), which sought and was granted a ring-fencing waiver in December 2020.[10] We understand that this waiver allows UE to grant a retail partner a right of access to the storage capacity of pole-mounted batteries as part of a trial project.[11] In setting out its reasons for waiving the relevant ring-fencing restrictions, the AER noted the potential high opportunity cost to the broader industry, and to consumers, if the trial did not proceed.[12]

Other distributors are proceeding with virtual trials that do not require ring-fencing waivers. For example, Ausgrid's community battery trial is exploring the potential of a customer battery storage service.[13] As part of phase 1, solar customers near three community batteries have been invited to 'opt in' to the trial and subscribe to a virtual allocation of the local community battery. While phase 1 of the trial does not require Ausgrid to apply for a waiver, going forward, we understand that Ausgrid intends to contract out battery capacity to a third party and to seek to trial the provision of customer battery storage services to customers for a fee.[14] The benefits to consumers from future phases of the trial will likely be conditional on the relaxation of current ring-fencing requirements that would prohibit such a service.

In contrast, in Western Australia, distribution businesses are not subject to ring-fencing requirements. This makes the community battery model straight-forward and several community-scale battery projects are underway, with distribution businesses using them to deliver significant price and reliability benefits to consumers.[15]

Competitive tenders for flexibility services

As discussed, there may be value in improving the regulatory incentives for distributors to use flexibility services and reducing transaction costs. However, we consider that adopting an equivalent of the Regulatory Investment Test for Distribution (RIT-D) in Australia would not be a proportionate solution to the potential issues expected in the New Zealand market.

The RIT-D and Regulatory Test for Transmission (RIT-T) are features of the much more prescriptive Australian approach to network revenue regulation where the AER closely interrogates all major investments proposed by network businesses as part of their individual revenue determinations. The RIT-D and RIT-T apply to all investments over a specified threshold. Their main purpose is to ensure that network businesses have tested all credible options and provide assurance to the AER as part of the revenue determination process that major investment proposals are efficient. While the consideration of non-network options is part of the process for some RITs, it was not the primary reason for introducing that requirement.

The New Zealand DPP process is very different to how the AER sets regulated revenues, and such a prescriptive investment test would be inconsistent with the DPP regime.

The Australian experience also shows that the requirement to undertake a RIT-T or RIT-D leads to significant additional costs and delays, but very rarely results in the adoption of a non-network solution.

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[10] AER, *Final Decision United Energy Ring-fencing Waiver Pole-mounted Battery Trial*, December 2020.

[11] In its application to the AER, United Energy proposed to purchase and install 40 new pole-mounted battery energy storage system (BESS) units in its LV network. The units will be used in a trial to provide distribution services to United Energy customers, with the unutilised capacity leased to an unaffiliated retailer partner, selected through a competitive tender process.

[12] AER, *Final Decision United Energy Ring-fencing Waiver Pole-mounted Battery Trial*, December 2020, p.9.

[13] See: https://www.ausgrid.com.au/In-your-community/Community-Batteries/Community-battery-FAQ

[14] *Ausgrid submission to United Energy Ring-fencing Waiver Pole-mounted Battery Trial application*, November 2020.

[15] See: https://www.westernpower.com.au/community/news-opinion/industry-spotlight-energising-a-battery-industry-from-the-ground-up/

We reviewed the RIT-Ds completed since early 2018 using a sample of four distribution businesses in Australia's National Electricity Market.[16] Of the 41 RIT-Ds completed by these businesses, only 3 resulted in a non-network option ultimately being identified as the preferred solution (either in full or in part). The time taken to complete the RIT-D process varied significantly, between 6 weeks and 18 months.[17]

Through existing competitive solicitation processes, distributors are able to pursue services with secure communication protocols, that integrate with our digital systems, and will deliver security and performance. It is important that distributors can set these requirements to ensure reliability and efficiency when planning and operating the networks. Given the nascency of the flexibility services market and current scale of resources, many providers face challenges meeting the performance and security requirements that distributors seek for services that act as an alternative to traditional capital investments. Addressing this through focused workshops with relevant industry participants would build a mutual understanding so that expectations are better aligned, and procurement processes can be efficient and effective.

Linking distributors' regulated revenue to their progress in developing the use of flexibility services

The Discussion Paper includes an option of linking distributors' regulated revenues to their progress in developing the use of flexibility services.

It is not clear to us how such a link could be created (and would appear a topic far more appropriate for the Commerce Commission to be canvassing). There would be a high risk that such an approach would not achieve the Authority's aim of incentivising efficient use of flexibility services, i.e. adopting them where the cost is lower than using a network solution. Instead, it would risk simply incentivising more use of flexibility services regardless of whether they were the most efficient solution, which would increase costs to consumers for no benefit.

A more appropriate alternative would be a more targeted incentive scheme to reward distributors for adopting efficient non-network solutions, such as a scheme like the AER's Demand Management Incentive Scheme, as discussed above. The lack of effective incentives has contributed to the gradual decline of hot water load control systems. With the revision of the transmission pricing methodology and the removal of the regional coincident demand peak charges, one of the clearest incentives for distributors and largest source of flexible demand is being expressly removed.

The Authority could clarify its views on non-discriminatory access terms for flexibility services by supporting an industry led effort to develop a template around non-price terms. This would improve interoperability across distributors.

However, there should not be 'standing offer' price information for DER. As previously noted, the value of DER is highly location and time specific. Each distributor would need to determine appropriate terms once they have sufficient visibility of their LV systems, DER behaviours, and future consumer loads (e.g. from EVs) on its network.

Appropriate funding to implement regulation

In our view, distributors must have appropriate funding to implement any new regulatory arrangements coming out of this consultation.

[16] Ausgrid, Endeavour Energy, Ergon Energy and AusNet Services. Further information on RIT-Ds completed or in progress can be found on these networks' websites.

[17] The process that a distribution business must follow when undertaking a RIT-D project assessment depends on several factors, including the estimated cost of the options being considered, and the feasibility of a non-network option providing all, or a significant part of, a potential credible option to address the identified need (that is, the network problem or limitation).

For example, the Authority recently requested, under s54V(5) of the Commerce Act, that the Commission reconsider Transpower's individual price-quality path (IPP) to recover additional costs of Transmission Pricing Methodology (TPM) development and implementation. [18]

Distributors have also incurred substantial additional costs implementing Authority regulation. For example, distributors incurred millions of dollars in costs implementing the Default Distributor Agreement (DDA). Despite this, we are not aware of the Authority invoking s54V of the Commerce Act to ensure additional distributor costs are taken into account in the Commission's price-quality regulation.

S54V requires the Authority to advise the Commission after taking various actions - including amending the Code or issuing guidelines - that may be relevant to the powers or functions of the Commission. S54V(3) requires the Authority to advise the Commission following any change in the Code that results in increased costs to Transpower or distributors. S54V(5) requires the Commission to reconsider a s52P determination if asked to do so by the Authority to take account of matters referred to in s54V(4). These matters include any guidelines issued by the Authority likely to be relevant to the Commission's powers or functions.

We request that the Authority provide guidance on when it would request the Commission to reconsider a s52P Determination under s54V(5). In particular, when it would request the Commission to reconsider a s52P Determination as a result of issuing new guidelines.

Consistent with its approach to Transpower's TPM costs, the Authority should exercise all powers available to ensure distributors can recover costs incurred as a result of new or expanded regulation developed by the Authority.

Part 2: Feedback on the issues and solutions identified by the Authority and responses to the consultation questions

Part 2 of this submission sets out our feedback on the level of significance and urgency of the issues or themes identified by the Authority in the Discussion Paper, and our views on the options the Authority identified for addressing those issues. It also sets out our responses to the consultation questions under each theme.

Issue 1: Information on power flows and hosting capacity

Vector considers accessibility of information to be a "significant" issue. However, we do not agree that the "significant option" of creating a central meter data store is appropriate for addressing data access issues, as the current best practices for reliable, secure, and adaptable data services utilise standardised interfaces (APIs) with decentralised data storage.

There is now widespread agreement amongst industry participants that access to smart meter data – both consumption data (e.g. half hourly data) and network operations data (e.g. power quality, voltage, etc) – is critical to improving visibility of the LV network and the DER connected to the network. With an expectation of more participants potentially accessing this data for both market and operational purposes it is critical that we do not depend on a single centralised resource.

Smart meter data is the key ingredient in increasing distributors' visibility of their LV network, enabling them to better support investments in data analytics, increasing their ability to understand and share data on power flows and hosting capacity. Greater access to smart

[18] Electricity Authority, *Letter to Commerce Commission: Development of a proposed new transmission pricing methodology (TPM)* (10 June 2020)

meter data will enable the provision of services that give consumers greater choice and control of how, where and when they use and discharge electricity. This supports the Authority's objective of promoting innovation and consumer participation in electricity markets.

Any consideration of data issues or proposed new data arrangements should consider the appropriate privacy and security settings.

In relation to hosting capacity, we note the dynamic and stair-step nature of capacity additions from customers, for example an area could have no capacity constraints and then several large customers could connect to the network, such as new data centres or the coincident construction of a large quantity of infill housing, creating a capacity constraint in a short period of time. As such, a hosting capacity map is always just indicative of the constraints at the time it was created, and expectations must reflect that new connection requests will still require verification and approvals.

Publicly available hosting capacity will also create an incentive to connect while availability is there. This may lead to inefficient network allocations where customers are reserving capacity but request more than they need just because it is available.

***Q1**. Have you experienced issues relating to a lack of information or uneven access to information?*

Vector's distribution business has experienced issues with accessing the half hourly consumption data currently generated by smart meters. This follows the Electricity Price Review (EPR) Panel highlighting the need to "ensure distributors have access to smart meter data on reasonable terms".

While we consider the development of the new Data Template in the Default Distributor Agreement (DDA) to be a step in the right direction, there remain a number of limitations that materially restrict the ability of distributors to use or share such data in the most effective way for their existing network operations. For example, distributors are prohibited from providing data obtained through the Data Template to third parties without the permission of individual retailers which is unworkable in practice.

The ENA and its member distributors expended significant effort to arrange data access by working with retailers to develop an amendment to the DDA Data Template. This was not adopted by the Authority, and therefore we must now pursue access to consumption data individually from each retailer. This is a time-consuming process and is a barrier to the development of flexibility services.

The result of these ongoing negotiations is that we do not expect to have access to half hourly consumption data with sufficient time to integrate it into the customer models that underlie our network planning processes. Therefore, we will again rely on the consumption data we were able to acquire from 2015 to develop load growth scenarios across our network and inform our asset management plan for 2022-2032. The Authority would help accelerate distributor's access to smart meter data by clarifying in the Code that distributors are permitted to engage directly with MEPs to access consumption data.

We are hopeful that a modified version of the existing data template will work (incorporating the changes that were declined by the Authority), however, agreeing terms for data provision with retailers and metering equipment providers (MEPs) for access to network data is a time-consuming process, and the need to negotiate terms adds to this complexity. Given that customer's may freely choose to switch to any retailer, there is a risk that the usefulness of data access will be limited if there are significant differences in how we may use data from different retailers.

As customers adopt new technology to enhance and support their lives, they are becoming stakeholders and participants in the energy system, as opposed to legacy "connection points" or “behind the meter loads”. We are seeing this already with smart EV charging in domestic environments. This shift demands a flexibility and preparedness from Vector to enable a customer-centric electricity distribution system and the integration of new technology in line with technology availability, desired policy outcomes, customers’ expectations and ensuring a secure and reliable electricity supply.

The experience of lockdowns and societal change from COVID-19 highlighted the need for flexibility and responsiveness to change, with less certainty now over future network demands as load profiles reflect changing work practices, such as an increase in working from home. Metering data on electricity use and power quality can identify these changing behaviours and their implications, and so it is critical for distribution companies to be able to access this data to understand and respond effectively.

***Q2**. What information do you need to make more informed investment and operation decisions?*

Vector is in active negotiations with two MEPs to obtain network operations data from the smart meters on our network. We have continued to use smart meter consumption data from 2015 as a foundational piece of our system planning processes in the absence of access to the data that is being collected daily from smart meters throughout our networks.

We are optimistic that, through these ongoing negotiations, we can obtain the data we need on an ongoing basis at reasonable prices, however retailers appear to have little motivation to resolve ongoing issues with distributor access to the half hourly consumption data from smart meters. This is evidenced by only a fraction of retailers, representing approximately 11% of the ICPs on our network, having agreed to the terms of our revised data template to date, and none of those retailers completing their engagement with the MEPs to allow the delivery of consumption data.

Barring any unforeseen obstacles, we expect the delivery of new network operations data services to commence in the first quarter of 2022, largely because distributors can engage directly with MEPs for these operational data services. This would be a big first step to increase visibility of our LV network, and enhance our understanding of the state of our network and the DER connected to it.

This data and the analysis that we undertake will help us manage our network more efficiently, respond to emergency situations safely and in a timelier manner. It will also allow our customers to maximise the benefits of new technology solutions that use DER and meaningfully contribute to lowering carbon emissions. See our response to question 10 for more information about how we use data to develop and use our granular customer model.

We understand some distributors are also in similar discussions about accessing network operations data from MEPs. We encourage the Authority to allow these processes to take their course and help facilitate them (where and when necessary), rather than pre-empt them with new or expanded regulation.

***Q3**. What options do you think should be considered to help improve access to information?*

Vector supports improved access to information but is also committed to complying with its obligations under the Privacy Act.

Vector agrees with the “minor issue” options set out in the Discussion Paper to address data access issues. These options involve informing and educating consumers on how to request their consumption data and encouraging distributors to collaborate in finding the most efficient way of capturing and publishing utilisation data.

We also agree with the “medium issue” options of assessing options to implement shared data arrangements and publishing guidance for distributors to report on export congestion and network investment needs.

We further support the use of Application Programming Interfaces (APIs) to share data.

However, we do not agree with the "significant issue" option of a central meter data store. A centralised approach will: 1) likely be very costly to develop and maintain, 2) duplicate existing data, 3) result in consumers paying for services they do not need or desire, 4) be less secure – if the centralised data system breaks down, everything breaks down, i.e. there is no redundancy, 5) delay the access to and use of the data, and 6) be incompatible with a Consumer Data Right (CDR) that is intended to be introduced in New Zealand. We note the shift in the CDR for the energy sector in Australia away from the centralised "AEMO gateway model" to a peer-to-peer model. This is driven by the need for more interoperability and extensibility of energy data within and across sectors – closer to the approach adopted for the CDR for the banking sector (Open Banking).

In addition to the minor and medium issue options set out in the Discussion Paper, we suggest that the Authority also explore the following options to improve access to information:

1. **Recovery of costs of improving visibility** - As indicated in Part 1 of this submission, an underlying cause of inadequate network visibility may be a lack of clarity or inability under the DPP regime to recover the costs of procuring smart meter data (e.g. ongoing rather than ad hoc access) and enable greater use of flexibility services. We suggest that the Authority and the Commerce Commission explore options on how distributors could be enabled to recover these costs, e.g. through an innovation allowance or pass-through under Part 4 and/or through some form of funding for innovation.

2. **DER register** – We consider this to be a 'no regrets' step that can provide significant value during the early stages of DER adoption. It can be a tool to help identify where DER adoption or growth on the network is occurring to assist with network planning. The Authority could consider who should administer such a register, what information is contained in it, how that information is gathered, and who can access it. In Australia, only limited parties have access to the AEMO DER Register – but our view is that it would be appropriate to make DER register data more widely available in New Zealand. A DER registry should include devices that may impact the network – in particular, including batteries and EVs. We note that the UK has acted to ensure that networks have visibility of all 'low carbon technologies' by requiring customers to notify their local network when installing solar PV, heat pumps, Electric Vehicle (EV) charging points, or battery storage to ensure safe and effective operation of the electricity networks. Ensuring that the process is easy for consumers should be a critical consideration. We suggest the most practical way to achieve this would be to extend the current installation control points (ICP) registry to include all forms of DER, but in particular EV chargers and battery storage.

3. **System visibility** – This could be enhanced by having workshops across the industry to determine what information distributors or others could provide to support DER integration, or there may be value in other bodies such as the Authority or MBIE developing resources covering all networks. For example, the Network Opportunity Maps in Australia provide interactive maps using spatial data from all distribution businesses on network constraints, planned investment, and the potential value of DER. These maps were not prepared because of any regulatory requirement and were initially developed by the Institute for Sustainable Futures and Energy Networks Australia with funding from the Australian Renewable Energy Agency (ARENA).

Issue 2: Electricity supply standards

Vector considers the issue of electricity supply standards to be of "medium" significance and a 'low hanging fruit' that can more easily be addressed relative to the other issues raised in the Discussion Paper.

Given the emergence of new technology solutions and business models in the electricity sector, we consider a review of the 'operating envelopes' for distributors (Part 6 of the Code) to be timely. This could involve, among others, determining the appropriate DER standards that would enable industry participants (including DER owners) to generate future value for the electricity system and consumers.

At this point of market development, the costs of adding "smart capability" at the time of installation are relatively low – particularly compared with the cost of retrofitting. Analysis undertaken by Frontier Economics found that even whilst 'smart' EV chargers carry a higher up front capital cost, compared with their passive counterparts, this is offset significantly by the system wide benefits that an EV smart charger adds – in terms of displaced generation costs, balancing value, as well as distribution deferral. Accounting for these system wide factors through a Whole Energy System Cost metric (WESC), a single residential smart EV charger could add a *net* benefit of $300NZD per annum in value to the system.[19] If it is accepted that EV chargers need to be regulated for health and safety proactively, which we support, the difference in cost between an Electric Vehicle Supply Equipment (EVSE) that has health and safety critical lock-out features (that would disable the flow of power if the EV is not connected correctly, for example) but no IP address *vs* one that does carry this 'smart' capability is marginal.

The value of smart EV charging is recognised by the publicly available specifications (PAS) 6010:2021 and 6011:2021. These standards – developed between Standards NZ, EECA, the Commerce Commission, the Authority, and industry participants – include a communications protocol for smart charging as well as health and safety standards. We support these standards. However, these standards are a voluntary guide. There is a risk that the market favours the product with the lowest up-front cost, but which would incur the higher whole-of life cost, and lowest health and safety, to all customers. Customers with little technical knowledge may not enforce the PAS 6011 through their purchase decisions.

As with the uptake of all low carbon technologies, the market should ensure that the option which delivers the greatest efficiency, health and safety, decarbonisation, and security and reliability – is the easiest and lowest cost. However, this does not always happen without Government action.

A trial undertaken by Australian power company, Origin Energy, found that 60% of trial participants had been plugging their car batteries into standard sockets in their garages, usually during the evenings before the trial[20]. In Vector's smart EV charger trial, no consumers were using a smart charger prior to the trial.

There are several potential levers, which sit across a number of government agencies, to ensure that safe, smart charging is the easiest choice for customers. We support for example, the review of EECA's Minimum Energy Performance Standards (MEPS) led by MBIE which included a proposal for standards to ensure that consumer energy-using products have 'smart' capability. In the UK, consumer incentives for smart EV chargers (that is, whereby 75% of the upfront cost of a smart EV charger is publicly funded through the Homecharge Scheme) has also been successful in driving uptake. Similar to energy efficiency and insulation, these investments deliver clear, and system wide, net public value.

As noted above, the draft release of Electricity Industry Amendment Bill 2021 proposes changes that would enable the Code to regulate some actors not currently understood as industry participants. However, this is only for the purposes of restricting relationships between two classes of industry participants, where those relationships would not otherwise be at arm's length. There remains an urgent need to ensure that a wider range of devices and distributed assets which are being installed today (and which increasingly have the scope to behave similarly to distributed generation – such as through bi-directional flows of

[19] https://www.weforum.org/agenda/2021/07/a-new-way-to-cost-the-energy-transition/

[20] https://www.smh.com.au/business/companies/batteries-on-wheels-the-smart-charging-tech-in-garages-needed-to-drive-ev-boom-20210621-p582tg.html

power as with Vehicle to Grid technology) have the capacity for dynamic management tomorrow. We encourage the Authority and cross-government counterparts to drive an agile and coordinated response to ensure this. (The AOG Pandemic response is a case study of where swift and coordinated action can be taken by Government – including at a legislative level.)

Given the criticality of consumer confidence in transport electrification to drive our decarbonisation pathway, this is one area where the proactive approach is the 'no regrets' approach.

***Q4**. Have networks experienced issues from the connection or operation of DER?*

Vector understands that the level of DER penetration in New Zealand remains low, and most distributors have not had to deal with systemic issues arising from DER integration. Local issues, e.g. power quality issues, can be addressed by the distributor and DER owner as they occur sporadically using current technologies.

Some distributors, however, are beginning to face significant challenges associated with the connection of DER. For this and the other reasons outlined in our response to Question 6, we would support a review of Part 6 of the Code, or aspects of it.

The rules around the application process for DG could be revisited to improve the information that EDBs 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 Certificate of Compliance 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 5 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 Certificate of Compliance (CoC). To resolve these issues, we must follow up directly with those customers to identify what has happened. In a scenario where millions of DER are being connected to the network, distributors will not be able to chase down each customer 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 distributed generation. 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, which we are currently negotiating with two MEPs that cover the bulk of the Auckland network.

Some additional challenges have emerged for DG installations on 3-phase network connections. When the DG is connected to a single phase on a 3-phase connection, customers face challenges in maximising the economic value of self-consumption of their generation resources. This is due to settlement occurring on the meter on each phase independently, whereby a customer may be exporting excess power from their DG on one phase and receiving a fraction of retail electricity rates while paying full retail electricity rates for the consumption occurring on the other two phases at their property. The Authority is the key party to address this issue via changes to the reconciliation requirements.

***Q5**. Do the Electrical (Safety) Regulations require review? If so, what changes do you think are needed (a) in the near term and (b) in the longer term?*

MBIE has already issued a discussion document on *Updating the references to standards in the electricity and gas safety regulations* in April 2021.

Our submission on MBIE's consultation, dated 1 June 2021, provided the following feedback on EV charging standards (among other electricity safety standards):

Health and safety hazards identified with the proposed amendment

Electric vehicles and charging technologies are evolving rapidly. The latest version of the electricity safety regulations should address the key safety issues associated with electric vehicle charging system for residential as well as for commercial charging stations. Associated voltage levels for charging stations and electric vehicles can be very high (up to 650V DC) and accidental contact with live parts can be fatal.

Earthing of the charging stations is a key tool which mitigates any health hazards associated with electrical faults. The proposed electricity safety regulation amendment creates confusion and conflicts around the earthing of the charging stations as it references both AS/NZS 3000:2018 and AS/NZS 3000:2007 in full. The current version of the standard introduces TT earthing system whereas the 2007 version recommends MEN earthing system in general. This will lead to health and safety hazards while working with electric vehicle chargers.

Several health and safety issues have been identified with both MEN and TT earthing system for electric vehicle chargers. British Standard BS7671:2018 and its amendmentA:2020 have addressed these issues and provide guidance. A similar approach should be taken for the New Zealand electricity safety regulations.

Issues with Existing MEN earthing system and the proposed TT earthing system as per the AS/NZS 3000 standard

The MEN earthing system which is currently adopted across New Zealand as per the current electricity safety regulations is a cost effective and safe option. But during open PEN condition (incoming neutral is broken), the voltage level on the neutral increases significantly. The chassis of the electric vehicle is metallic and poses significant health hazard during such condition. Several ways of mitigating this risk have been adopted in the UK such as having an isolation transformer, installing equipment that detects open circuit voltage, and electrical separation.

One of the other ways is to implement TT earthing system which also has several issues such as:

- *simultaneous contact between exposed-conductive-parts, such as the vehicle on charge (connected to the TT earthing system) and exposed metalwork connected to the PME earthing system;*
- *risk of striking buried services when installing earth electrodes;*
- *separation below ground between the TT earth electrode and buried metalwork connected to the PME earthing system; and*
- *return of touch potential.*

Recommended inclusion in the updated electricity safety regulations

The issues discussed above have been investigated in detail by IET UK and the British Standards Institution. MBIE's ongoing update of New Zealand's electricity safety regulations should take these factors into account and provide guidance for charging station owners to design the earthing system appropriately.

These issues are discussed in detail by IET UK (link: The IET Code of Practice for Electric Vehicle Charging Equipment Installation, 4th Edition - Electrical) in the IET Code of Practice for Electric Vehicle Charging Equipment Installation, 4th Edition.

Our submission supported MBIE's intention of developing longer-term solutions that would enable references to standards in the electricity and gas safety regulations (and any related regulations) to be updated in a more timely and responsive manner.

Section 28 of the Electricity Safety Regulations specifies network voltage operating limits of +/- 6% of nominal voltage should be reviewed and potentially changed to allow additional headroom for DG resources to inject power onto networks.

In order to meet the lower bound of the voltage supply requirements (6% less than nominal voltage), distribution transformers are often set at a default of 3.75% above the nominal voltage to ensure sufficient voltage will be available at the end of a distribution feeder during periods of peak demand. However, this setting could limit the amount of DG that can be safely injected on the network and in some cases has curtailed customer's DG output under normal network operating conditions.

The strict upper voltage bound of +6%, could be increased to 10% in the Electricity (Safety) Regulations creating more headroom for DG to inject power safely. This would also align New Zealand's settings with those used in Australia, and given our common equipment and appliance standards, there should be minimal risks to the operation of customer-owned equipment from this change.

***Q6**. Does Part 6 remain fit for purpose? If not, what changes do you think are needed (a) in the near term and (b) in the longer term?*

Vector supports a review of Part 6 of the Code (*Connection of distributed generation*) to consider, among others:

1. Reviewing the operating envelope to ensure that energy storage systems, EVs and demand response are captured;
2. Reconsidering restrictions on distributor-owned generation which can help improve local resilience and reduce dependence on additional transmission and generation at a national level. As discussed in Part 1 of this submission, there is already significant oversight of distributors by the Commerce Commission under Part 4 of the Commerce Act;
3. Connection rules for DER, including timing for and queuing of large-scale connection applications and cost recovery for these types of connections, including the costs for assessing the network impacts of a new connection;
4. The need for a DER registry which could record information on energy storage systems and batteries (and as described in our response to Question 3);
5. Reviewing the DG pricing principles which may not be fit for purpose for flexibility services, e.g. reconsideration of the incremental cost cap; and
6. Reviewing the processes, timings, and fees for connection applications.

***Q7**. Is there a case to be made for minimum mandatory equipment standards for DER equipment, specifically inverter connected DER?*

Minimum mandatory equipment standards are already in place for inverter connected DER that export power to the network, such as PV, battery systems, and vehicle-to-grid EV chargers. These standards should be regularly reviewed to keep pace with the introduction of new international standards. New Zealanders would benefit from the use of best practice international standards for these products.

***Q8**. What standards should be considered to help address reliability and connectivity issues?*

Vector supports a Code amendment relating to inverter standards that would incorporate the power quality response modes set out in the relevant standard (AS/NZS 4777).

There is an increased risk to connecting millions of DER at customer sites which may impact local and national electricity security. Attention should be paid to the cybersecurity risks associated with the communications pathways used in these devices to ensure there is no additional risk added to the system through the integration of DER.

This topic would be best reviewed across the sector and would be an additional opportunity for an industry wide workshop to assess the communication, data, and security needs at for the different levels of the electricity system.

> ***Q9**. Is there a case to look at connection and operation standards under Part 6 with a view to mandating aspects of these standards?*

The purpose of mandating standards is to support consistency and certainty across the emerging DER market – and to ensure that the greatest consumer value is realised from DER now and in the future. To implement this purpose, it is important that the Authority consider where mandating standards would deliver the most value and where it would increase certainty in the market.

A 2020 review by the ENA on distributors' connection standards found no material differences in distributors' connection and operating standards in relation to DG installation. Mandating aspects of some existing standards may therefore deliver little benefit through further standardisation and could result in the unintended consequence of disrupting effective processes, such as constraining the ability for connection agreements to evolve dynamically in response to changing customer needs as the standards body or regulator would need to be involved to update the standard.

However, as indicated above, there is an opportunity to look ahead in ensuring that the appropriate DER standards are in place to generate the most future value for the electricity system and consumers. We would support a review of Part 6 of the Code to reconsider the operating envelope for distributors, restrictions on distributor-owned generation, and connection rules for DER, among others. As discussed above, we see strong consumer value to be gained from mandating the installation of smart chargers – that is, ensuring that all EV charge points installed have an IP address and health and safety features.

The volume of applications to connect DER (PV and battery) to the LV network over the past few years has not been significant, and standards do exist to ensure the safety and reliability of the network. However, the recent acceleration of the EV market in New Zealand (which was identified in Sapere's cost-benefit analysis as the most significant opportunity from enabling DER flexibility) creates a significant opportunity for flexible EV charging – it also creates an priority for settings which enable dynamic management of EVs. This will not be possible without having chargers capable of receiving and reacting to communications signals. There is a significant opportunity to review and introduce standards for EV charging that create a future pool for flexible demand management for the very near future.

Hot water heating is another significant source of demand flexibility which is being utilised around the world. Should demand response capability become a requirement of any new electric water heaters, the magnitude and spread of that resource would grow over the next 10 years as new equipment is replaced as part of the natural lifecycle. This is a widespread resource that could be available for utilisation by the electricity sector for demand flexibility within the 2030 timeframe outlined in the Discussion Paper.

Issue 3a: Market settings for equal access – options for incentivising non-network solutions when they are more efficient than network solutions

Vector considers the development of market settings for efficient non-network solutions to be of <u>minor</u> or <u>medium</u> significance at this stage of market development.

With limited visibility of our LV network – hampered by data access issues – we do not have robust knowledge of when or where to use flexibility services most effectively. We have a limited view of available or accessible resources that could be utilised to deliver non-network solutions that are more efficient than network solutions.

Current regulatory settings do not reward opex (with risky performance characteristics) in place of near riskless capex investment. Distributors would benefit from an expanded ability to conduct trials that enable us to better understand the risks of, and opportunities from, alternative solutions.

Pursuing the Authority's options under the "minor" and "medium" issue categories (e.g. the development of voluntary guidelines, templates, and DER registry) will help advance collective knowledge based on real data and can better inform future regulatory decisions.

***Q10**. What flexibility services are you pursuing?*

Vector is currently pursuing or trialling flexibility services that use the following technology solutions:

1. **Hot water load control** - Vector has over 100 MW of instantaneous demand response available through hot water load control and we have trialled more advanced forms of load control using new technologies. Customers with load control benefit directly through a lower price for line charges, and all customers share in cost savings and reliability benefits due to load control materially reducing our peak demand. We also recently used our load control capability in Waiheke Island to manage winter peaks and avoid outages while an urgent network upgrade was undertaken.

2. **Peak time rebates** - We partnered with a retailer on a peak time rebate trial assess the products ability to help manage winter peak demand. We have also offered to provide access to our load control functionality to retailers to enable them to offer services to customers.

3. **Grid-scale batteries** - We are operating 4 grid-scale battery storage systems totalling 7 MW and are trialling aggregated behind-the-meter battery systems with third party vendors. We have recently used our grid-scale batteries to support recovery from an unplanned outage, restoring power to all affected customers within one hour instead of the usual 12 hours.

4. **EV charging trials** - We are also undertaking several EV charging trials, which will be integrated with our DERMS platform to support network emergencies and contingency events and help reduce peak demand.

5. **Standby emergency supplies** - We deployed emergency standby generation at Piha and South Head to provide local support during emergency and contingent events. These parts of the network are isolated and not accessible during severe weather events.

With low adoption rates for DER that offer flexibility services in New Zealand, it is challenging to utilise them to defer infrastructure investments. *The Value Of Integrating Distributed Energy Resources In Texas*[21] found: "When the magnitude of DER resources is a small share of the feeder capacity, say 5%, the deferral period may be insufficient at most locations to defer T&D in practice." Alongside low penetration in New Zealand, Vector have seen rapid load and customer growth in Auckland on our network, which further limits the opportunities for flexibility resources to be the most efficient investment.

EDBs need to ensure that a DER solution provides similar power system reliability as traditional investments, and that we have the systems and information flows to utilise them efficiently. If DER are not able to provide similar power system reliability, then this additional "cost" for utilising DER must be accounted for when comparing to traditional solutions. When

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[21] *The Value Of Integrating Distributed Energy Resources In Texas*, Demand Side Analytics. https://www.texasadvancedenergy.org/#report

we specify a traditional 'poles and wires' solution on the network, we know precisely what it's going to cost and how it's going to perform, whereas the performance uncertainty that exists for many DER solutions including energy efficiency, demand response, solar, EV charging and batteries creates new challenges which can only be answered through real-world trials.

Vector has developed significant in-house capabilities in data analytics, as evidenced by our recent publication, *Towards customer-centric energy utilities - A granular data-driven bottom-up approach to understanding energy customer trends* in The Electricity Journal.[22] This details the development of Vector's granular customer model that underpins our network demand modelling used in our network planning process. Developing these capabilities was driven by the need to understand the uptake of DER, customer behaviour and consumption impacts to adapt our planning processes.

In the past, distributors were delivering energy from transmission system grid exit points (GXPs) to consumers, and we were able to use generalised models for installation control point (ICP) load shapes to build and operate resilient and reliable networks. As DER and flexible resources are located at consumer ICPs, those generalised models will no longer be valid.

The core value of our granular Auckland customer model was unlocked by linking data sets from different sources to half-hourly smart meter data, something that the new data template in the DDA makes particularly challenging. Two data sets were of very high importance to the model. The first was census data from New Zealand's national statistics organisation, Stats NZ, which provided important information on customer demographics (e.g. income, family makeup, employment, tenure). The second was detailed property information for all rateable buildings in Auckland provided by Auckland Council. The Property Valuation Roll includes dwelling characteristics such building type, material, age and floor area.

In addition to those two fundamental datasets, we match ICPs to registers of premises with DG and storage, social housing sites, sales of domestic heating & ventilation products, alternative commercial and residential fuels (e.g. bottled LPG and reticulated natural gas), local government urban development plans, and building consents. Lastly the outputs from Vector's technology pilot studies (e.g. load management, EV charging etc) and the outcomes of behavioural research that we have undertaken is critical to keeping the model current and relevant to our local market.

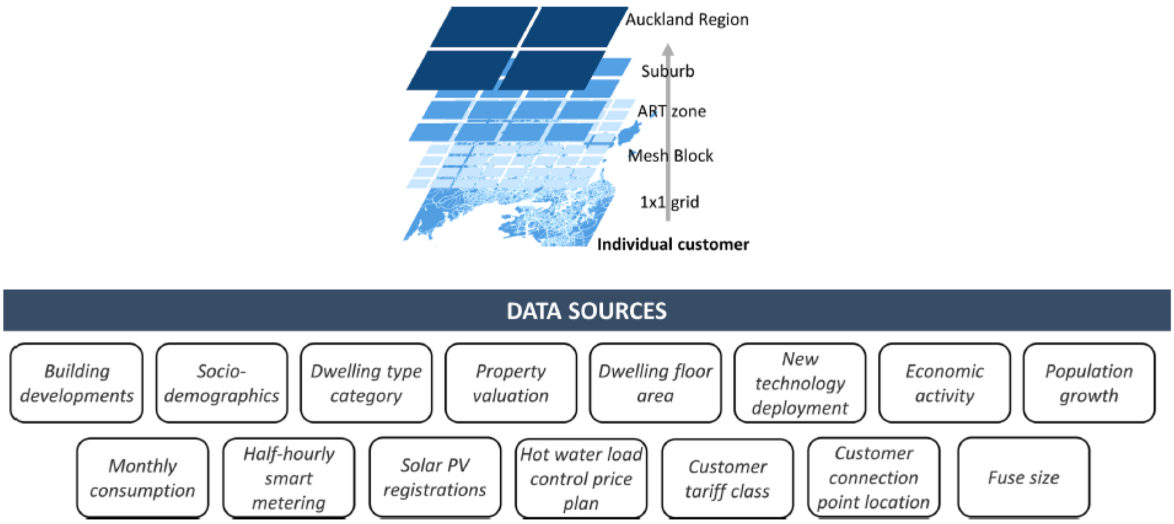


Figure 1 - Data sources and geospatial layers in Vector's Granular Customer Model

[22] Steve Heinen, Pieter Richards, *Towards customer-centric energy utilities - A granular data-driven bottom-up approach to understanding energy customer trends*, The Electricity Journal, Volume 33, Issue 9, 2020.

To date the smart meter data we have access to is from 2015, and as Electric Power Research Institute (EPRI) research noted: "Detailed modelling and analysis of DER at the feeder level is necessary to understand fully the consequences of DER. … The net benefits of employing DER as an alternative to conventional grid upgrades is hard to generalize, and depends on a complex set of parameters… including local-area load-growth rates, peak-day load profile, types of available DER, power system design, the time and location of the grid upgrades, and customer-adopted DER. DER may provide benefit in some instances; but it may not always be the best alternative."[23]

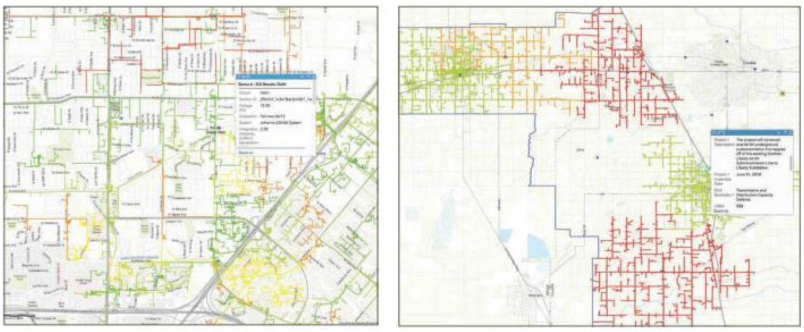
Once data access from the DDA is workable and we are able to access more recent and regular half hourly data from smart meters, we expect that we will be able to leverage the significant amount of work already undertaken internally to better understand the localised value of flexibility on our network.

We see the following generalised steps for the utilisation of DER:

1. Gain data access, build consumption forecasting and system capability models;
2. Develop system predictive (near real time) models and DER coordination capabilities;
3. Identify constraints, system optimisation and investment deferral opportunities;
4. Implement approaches and mechanisms to utilise DER capabilities; and
5. Assess the impacts and continuously improve on methods for DER utilisation

We expect that the value from distribution network infrastructure deferrals will be highly dependent on locality, as seen in the analysis done by Southern California Edison[24]. Within one suburb, the full spectrum from high deferral value to zero deferral value from DER can be seen, showing the potential shortfalls of setting generalised values for demand flexibility.

Figure 4. Maps showing integration capacity (left) and locational net benefits (right).[36]



On the left panel, green indicates distribution line segments that can easily host additional DER capacity; red indicates little or no hosting capacity; yellow and orange are in between. On the right panel, green indicates line segments with higher expected value for DER due to an opportunity for deferral of distribution capacity upgrades; red indicates little or no value; yellow and orange are, again, in between.[37]

***Q11**. Are flexibility services being pursued through a competitive process?*

Pursuing flexibility services involves contestable procurement processes or procuring services from a third-party provider, where appropriate. We already use these processes for other investments like infrastructure and digital projects. This allows solutions to be evaluated across multiple criteria including cost, timing, provider quality, and technical specifications.

As identified in our response to Question 10, we have utilised our load control functionality

[23] *Time and Locational Value of DER: Methods and Applications*. EPRI, Palo Alto, CA: 2016. 3002008410

[24] *Getting the Value of Distributed Energy Resources Right*, Institute for Policy Integrity, https://policyintegrity.org/files/publications/Value_of_DER_Report.pdf

with a retailer as part of our peak time rebate trial, and are trialling aggregated behind-the-meter battery systems with third-party vendors.

In the context of the rapidly evolving electricity sector, any party can conceptually be a producer, consumer, trader, or aggregator of electricity services. The convergence of new and emerging roles and services, enabled by new technologies, makes assessment based on existing market roles/segments less compelling and necessitates the use of competitive tenders.

Issue 3b: Market settings for equal access – options for increasing competition for flexibility services

Vector considers the development of options for increasing competition for flexibility services to be an issue of <u>minor</u> or <u>medium</u> significance.

Distributors and their customers currently bear the costs of network investment. As a majority customer-owned distributor, we are driven to enable DER connections and develop flexibility services to help make our network 'asset light' and avoid costly traditional 'poles and wires' investment. Using smart technologies and platforms that enable non-network solutions helps us to achieve that and provides our customers greater control over their energy use and production.

DER has a crucial role to play in supporting network resilience (e.g. through demand response programmes) and energy affordability (e.g. by providing consumers greater control on when they use electricity based on near-real time pricing information).

We are preparing our network to manage bi-directional or multi-directional flows of energy and the increasing uptake of DER, of which the most prevalent is electric vehicle charging. Distributors may not always need direct control of DER, but there will be scenarios where direct control is needed to ensure network security (like what AUFLS provides to the System Operator). It is therefore important for distributors to be able to build a portfolio of flexibility services – via a mix of direct control and fixed and/or flexible contracts – to manage network performance risk.

***Q12**. What options should be considered to incentivise non-network solutions?*

The Commerce Commission includes an innovation project allowance in the DPP regime, but the level of funding has been very low with stringent conditions, making it hard to access. The total allowances available for all distributors in the current DPP period is $6 million, which equates to an average of only $80,000 per distributor per year.

Overseas regulators have been more proactive in incentivising innovation that could result in short term increases in network prices but lead to long term reductions in total system costs. Ofgem has used a range of approaches to innovation funding for electricity distributors, including a Network Innovation Allowance and an Electricity Network Innovation Competition for its current electricity distribution determinations and a proposed Strategic Innovation Fund for its upcoming determination.

In Australia, the AER has established a Demand Management Innovation Allowance and a Demand Management Incentive Scheme to help electricity networks invest in non-network solutions that might otherwise not be financially practical. ARENA funds a range of innovative DER trials including several projects related to developing network 'operating envelopes' to assess and communicate DER hosting capacity.

We encourage the Authority and Commerce Commission to consider the above approaches, and those identified in Part 1 of this submission, for funding potential non-network solutions.

The nature of the DPP regime can make it challenging for distributors to recover significant 'step changes' in expenditure to meet new obligations or government or community expectations (for example, where significant expenditure is required to improve LV visibility and host increased amounts of DER). This expenditure may increase network costs but reduce total system costs, for example, by reducing wholesale costs if more DER can be connected and dispatched. As previously noted, the AER has recently published several guidance documents on how it will assess DER integration expenditure, where expenditures are viewed within the context of long term DER integration strategies and is beginning to consider the whole-of-sector benefits of DER integration.

***Q13**. What options would encourage competitive procurement processes for flexibility services?*

Vector considers the assumption in the Discussion Paper that distributors may not undertake competitive procurement processes for flexibility services, or may cross-subsidise or discriminate in favour of their business or a related business, to be misguided. There is no evidence of this behaviour or proclivity occurring, and there are extensive regulatory arrangements in place that protect against this risk, as discussed in Part 1 of this submission.

The Commerce Commission has extensive powers over distributors to address competition risks, including through:

1. Information disclosure, including scrutiny of cost allocation and related party transactions. We note that the Commission has undertaken reviews of related party transactions which found no evidence of distributors being anti-competitive;
2. Price-quality regulation;
3. Court proceedings to enforce breaches of the first two requirements;
4. Reviews of Asset Management Plans;
5. Market studies; and
6. General consumer protection legislation.

The Commission’s related party rules impose disciplines on procurement of services by the regulated supplier from related parties. The risk of cross-subsidisation only exists where there is scope for the distributor to earn supernormal returns from its regulated network services, or to inefficiently allocate assets that provide competitive services into the Regulatory Asset Base for monopoly services. As a regulated distributor, Vector will continue to transparently report its cost allocation methodology.

Distributors are internally accountable to their board and shareholders (who in many cases are also their customers) and externally to customers and regulators through the above requirements. As a highly regulated business, we are attuned to the risk of price shocks to consumers and take this issue seriously.

Significant disclosure rules and reviews by the Commerce Commission show the assumptions are not borne out by the evidence, i.e. there is no evidence that distributors are undertaking procurement processes that preclude flexibility services.

The Commerce Commission’s review into distributors’ Asset Management Plan reporting shows ample evidence of competitive procurement processes being actively used by distributors.

We therefore consider that the existing regulatory requirements (identified above and in Part 1 of this submission) adequately address this potential issue. The Authority should therefore focus on the untreated issues above rather than implementing unnecessary and costly mechanisms to address risks that are already dealt with by existing/other requirements.

Issue 4: Operating agreements – Options for reducing barriers to contracting for flexibility services

Vector considers the issue or need for operating agreements to be a minor one.

Vector already engages many third-party service providers for infrastructure, operational, and digital projects using competitive processes. These processes serve us well, allowing us to evaluate proposals by multiple criteria such as cost, technical requirements, delivery timelines, and each provider's track record and qualifications. We see no reason why flexibility services would be any different once the market reaches a higher level of maturity.

Distributors need visibility first to understand the operating envelopes that are appropriate for them and define their needs. Distributors and third parties can then work together to determine the appropriate expectations for performance requirements and risk allocation that meet the needs of both/all parties.

The costs to consumers of unintentionally stifling innovation through greater prescription in the form of a mandated operating agreement can be high. There could be merit in developing an industry-led template for non-price terms, which we describe in our response to Question 16 below.

We believe there are effective regulatory levers that can unlock consumer benefits without the downside of limiting innovation, including in contracting. These levers include improving information (i.e. greater LV visibility) and implementing wholesale market reforms, as highlighted by the EPR.

***Q14**. Have you experienced difficulties with negotiating operating agreements for flexibility services?*

Vector generally has not experienced difficulties with negotiating operating agreements for flexibility services. However, the nascent state of the market in New Zealand, and the need for visibility to assess how services would be best suited to address different operational challenges on the network can make negotiating an agreement challenging. In Auckland, we have seen rapid load and customer growth, which limits the time periods that flexibility resources could be used to defer an infrastructure investment, thus limiting the opportunities for providers and distributors to use them as an efficient investment decision. Vector does not control the location or timing decisions of new load which is generally influenced by aspects unrelated to electricity costs such as proximity to other infrastructure, urban planning changes, etc.

While there is increasing interest from the market, we have not received many requests from third party service providers. We have engaged with several electricity sector participants to explore the use of battery storage, smart EV charging, and hot water load control through commercial arrangements. Many approaches from third parties remain speculative and have not led to negotiation for an operating agreement.

***Q15**. Are the transaction costs of developing contracts a barrier to entering the market for flexibility services?*

The fledgling nature of flexibility services and rapidly evolving nature of the electricity sector demand arrangements that promote flexibility and preserve optionality. Developing a mandated operating agreement is not too far short of 'picking winners' that could 'lock in' existing solutions and 'lock out' alternative solutions that could better deliver benefits for consumers.

We prefer an industry-based approach to achieving a shared understanding and shared expectations about flexibility services. In our engagements with various industry participants on DER integration, all distributors/retailers/potential market participants have been open to preserving optionality and developing an industry led approach delivering flexibility services.

The contracting challenges for flexibility services are not due to an imbalance in bargaining positions, but rather reflect the early stage of the flexibility markets in New Zealand, and the lack of data that is affecting all parties capability to determine the value for flexibility services. Gathering the relevant industry players for workshops to answer questions on these issues would lay the foundations, after which contracting terms are left for commercial parties to negotiate.

All providers stand to gain from the terms negotiated by others without needing to negotiate those terms themselves. However, if a third party wants to negotiate better terms than are offered, then they should have the option of doing so. New entrants are then able to free ride on an ongoing rigorous contract development process.

***Q16**. Would an operating agreement help lower transaction costs and level negotiating positions?*

In Vector's view, a standard operating agreement for flexibility services will only yield the 'lowest common denominator' that limits future innovation – and is therefore not in the best interest of consumers. The development of an operating agreement in a rapidly evolving electricity sector can be challenging and time consuming, and therefore not cost effective.

The costs of establishing an operating agreement for all distributors are likely to be significant, as the experience with the DDA has shown – which took many years to finalise and still has unresolved issues around its Data Template. The efficiency gains from a one-size-fits-all operating agreement is highly diminished in a rapidly evolving sector where assumptions can change within short periods of time.

In addition, under a 'one-size-fits-all' operating agreement, consumers could end paying for features or services they do not need or desire, which is inefficient.

It is reasonable to expect that distributors may, over time, find it more cost-effective to develop modules or template agreements to facilitate the connection of more DER to their network. It is in distributors' interest to make connection agreements as streamlined as possible to reduce the transaction costs for all parties, which ultimately benefits their customers.

There is a real risk that a common operating agreement at this stage can stifle innovation that can benefit consumers. Agreements that reflect the characteristics of a distributor's network and the unique needs of its customers and the DER owners applying for connection avoids the real risk of stifling innovation, including contracting innovation.

However, as suggested in Part 1 of this submission, there could be merit in developing a template operating agreement for non-price terms. This should be led by interested industry participants with the Authority's input, rather than drafted and imposed by the Authority. Such a collaborative approach will better address the key issues faced by participants. There should not be 'standing offer' price information for DER. The value of DER is highly location and time specific, so standardised prices would be inefficient and impose unnecessary costs on customers of the distribution business. Similar proposals for standardised prices for DER services provided to distributors were rejected by the Australian Energy Market Commission (AEMC) for that reason, with the AEMC deciding that improved information was a more efficient solution.

***Q17**. What kind of operating agreement would address the issues described in this chapter?*

Vector believes that operating agreements with the following features would help address the issues described in Chapter 7 of the Discussion Paper and would be in the long-term interest of consumers.

1. **Promotes innovation** – Agreements that are adaptable to a wide range of business

models, technology services and technologies are appropriate for flexibility services which are in their infancy, rather than a mandated/common operating agreement that unnecessarily restricts market, regulatory, business model and contracting innovation. Diversity in contractual agreements reflect competitive pressures and meaningful commercial negotiations in the market.

In Vector's case, household growth in Auckland has a much greater impact on our network than in the past, creating new expectations on us to deliver on our existing functions and adopt new roles and technology which need to be supported by flexible regulatory tools. It is therefore important that our contractual arrangements/agreements provide us with greater ability to utilise new energy sources and new technologies rapidly to substitute for traditional supply when and where necessary. As such, we prefer industry-based approaches that would allow the appropriate solutions for an immature market to emerge. We want to be open to the solutions and options that emerge from gaining greater visibility into our network.

2. **Preserves optionality** – In the dynamic electricity sector, where more complex arrangements and uncertainties are emerging (e.g. load growth driven by EV uptake), regulatory innovation is both possible and necessary. An increasing number of transactions in the market will correspondingly require increased options for market participants so they can compete and deliver the best outcomes for their customers, e.g. new technology solutions that support network resilience. This involves allowing the best possible regulatory approach to emerge. In some cases, this may require suspending existing rules such as the "regulatory sandbox" approach implemented in the U.K and Canada, and which is proposed in Australia.

3. **Is cost effective** - The static efficiency value of a standard operating agreement is diminished in a rapidly evolving market where participants' roles are converging and where market segments are becoming artificial. Technological change tends to cut across different vertical segments in the electricity market. In considering the costs and benefits to consumers, we believe it is more appropriate to take a broader view of how efficiencies can be realised for consumers.

   Any cost-benefit assessment in a highly dynamic market needs to consider the possibility of chilling innovation as an unintended consequence of adopting a 'one-size-fits-all' approach.

4. **Recognises that distribution networks evolve at different speeds** - Imposing an operating agreement on distributors across the country ignores the fact that distributors operate in different contexts and will evolve at different speeds. For example, while most regulated distributors are subject to the DPP regime, some are (or in the future could be) on a customised price-quality path by virtue of their unique circumstances.

5. **Does not remove the option for negotiation** - As more service providers enter the market, and as market transactions become more complex, customers are expected to seek more customised terms that cater to their unique needs, which involves negotiation. The evolution of the regulatory framework itself could also trigger the need for new negotiations or re-negotiations of contractual terms.

Issue 5: Capability and capacity

Vector considers capability and capacity issues, as set out in the Discussion Paper, to be <u>minor</u> issues.

Auckland's population is projected to increase to 1.9 million by 2025. Leveraging the local benefits of DER will help Vector support this growth in a way that is sustainable and affordable by reducing customers' reliance on centralised sources of power. The current regulatory and market arrangements focused on existing market segments need to evolve to ensure potential efficiencies and consumer benefits can be realised.

DER have a critical role to play in supporting network resilience, energy affordability, and the transition to a net zero emissions economy. There are not many firms in New Zealand that both have the capacity and the incentive to invest in disruptive energy innovation. Allowing distributors to invest in DER in support of these objectives is unlikely to squeeze other players out, given the competition risk mitigations identified in our response to Question 13 and Part 1 of this submission. Disallowing distributors to make such investments would severely limit innovation in the market.

Meeting the challenges of the industry's transition to a smarter grid requires a regulatory approach that considers opportunities not only for innovation and competition, but also for coordination.

The cost of coordination failures is most evident in relation to the introduction of new technology, which tends to cut across the boundaries of artificial market segments. We need to ensure our network is resilient to both traditional challenges (asset age, condition, the weather) and new ones (changing technology and consumer behaviour). There are different ways of achieving resilience, including through collaboration in harnessing the capability of new technologies.

We do not consider institutionalising the role of Distributed System Operator (DSO) to be a medium or significant issue; it is not a low-regrets step. The cost-benefit analysis from Sapere itself indicates that the benefits from DER will largely be realised after 2030 and are not exclusively attributed to distribution. The Authority, in conjunction with industry participants, should ensure we move prudently to avoid 'over-regulation' that can limit future flexibility and innovation. A key question to consider is whether the DSO or Distributed Network Operator (DNO) role is substantial enough at this stage to justify it being a separate role.

***Q18**. What are distributors doing to ensure their network can efficiently and effectively manage the transformation of networks?*

Vector is partnering with other distributors, retailers, and our own customers to promote DER integration and help ensure the efficient and effective transformation of our network. Ongoing initiatives towards this end include, among others:

1. The flexibility services and trials Vector is pursuing – These include hot water load control, peak time rebates trial, grid-scale batteries, and smart EV charging trials (described in detail in our response to Question 10);
2. Vector Technology Services developing digital services that better enable networks to navigate the transition to a digital energy future, e.g. cyber-security tools, DERMS, Advanced Distribution Management System (ADMS), the recently announced collaboration with Google's X, the moonshot factory, and New Energy Platform within New Zealand;
3. Developing our scenario modelling capabilities, which are built on the Auckland Granular Customer model, and are used to inform our future planning processes. More detail can be found in our response to Question 10.

***Q19**. How are distributors currently working together to achieve better outcomes for consumers?*

Partnerships are a key element in delivering better consumer outcomes. In addition to the initiatives mentioned in our response to Question 18, distributors are currently working together to achieve better consumer outcomes through the following initiatives:

1. Distributors working with MEPs to develop a common set of smart data services that will enable distributors to have greater visibility of their LV network (described in our response to Question 2);

2. ENA members partnering with the Electricity Engineers' Association to develop technical standards for DER, i.e. EV charging and inverter standards;

3. Network Transformation Roadmap (NTR) developed by the ENA's Smart Technology Working Group. The NTR provides information, insights and recommended actions for distributors as they facilitate the transformation of their networks. It aims to guide distributors in planning and developing their networks in a way that maintains flexibility in a period of disruptive change and provide a coherent vision for the future role of distribution networks in New Zealand. The NTR is currently being reviewed and refreshed to capture recent technological, market and regulatory developments.

4. Providing support during emergency response and recovery efforts;

5. Sharing best practices and learnings from trials, such as the recent workshop on microgrids and remote power systems facilitated by the ENA, our collaborations with the Northern Energy Group, and working with other industry bodies like SEANZ such that we can learn from related best practices;

6. Collaborating during COVID-19 to ensure supply chain security and network resilience and developing collaborative solutions to strengthen community resilience during COVID-19 outbreaks; and

7. North Island Distributors are collaborating on shared equipment standards to address supply chain challenges

Vector is also partnering with the Electricity Retailers Association of New Zealand (ERANZ) in support of the EnergyMate project to deliver energy efficiency education and support for families in hardship. Our scale and community ownership make us well placed to make the most of this opportunity.

A large portion of Vector's customers live in energy hardship and as a majority customer-owned distributor, our interests are naturally aligned with our customers' interests.

In the context of the above developments, it becomes increasingly clear that a siloed Part 4 of the Commerce Act does not lend itself well to increasing collaboration between distributors and with third parties across the electricity sector and beyond, e.g. transport.

***Q20**. Could more coordination between distributors improve the efficiency of distribution?*

There is strong ongoing coordination between distributors to improve the efficiency of distribution, for example, to reduce duplication of effort and learn from each other's trials. These should be encouraged rather than stifled through premature regulation which is 'fragile by design'.

The Authority (working with the Commerce Commission where relevant) can facilitate not only stronger coordination between distributors but also incentivise distributors' engagements with third party service providers by:

1. Enabling improved visibility of distribution networks and DER through:
    a. system visibility
    b. resource visibility; and
    c. provider visibility;

2. Incentivising distributors to use flexibility services and increase their DER hosting capacity through:
    a. provider visibility;
    b. reporting on the use of flexibility services in AMPs;
    c. engagements with flexibility providers; and

d. development of an operating agreement template for non-price terms for flexibility services; and

3. Minimising transaction costs for the use of flexibility services as non-network alternatives through:

   a. recovery of costs of improving visibility and integrating DER;
   b. calibrating incentives for capex and opex trade-offs;
   c. funding for innovation;
   d. quality requirements and incentive schemes; and
   e. guidance materials for smaller distributors.

The above recommendations are discussed in Part 1 of this submission.

Sapere's cost-benefit analysis indicates that the material benefits from DER will not be realised until after 2030. This gives distributors and existing and potential industry participants opportunities to learn and innovate and deliver flexibility services that are in consumers' best interest.

While flexibility services are immature, greater prescription could create unintended barriers to DER adoption/integration, the development of flexibility services, and greater mass market participation. We need arrangements that remove these barriers and allow regulatory frameworks to evolve, innovation to flourish, and new solutions to be developed.