Issues paper: Updating the Regulatory Settings for Distribution Networks

December 2022

Contents

1 Executive Summary

1.1 This issues paper builds on the discussion paper released in July 2021 as well as the follow-up information request circulated to distributors and flexibility traders in March 2022. It is written in several chapters that address different aspects of the regulatory settings for distribution networks: access to data, market settings, capability and capacity, operating agreements, and standards. Each chapter identifies some tentative options.

1.2 In the 2021 discussion paper, potential issues were identified as follows:

(a) distributors may favour network solutions when non-network solutions could be a more efficient option. This means opportunities might be missed to support climate targets and decrease distribution costs; and

(b) if distributors do decide to invest in Distributed Energy Resources (DER)[1], they may be more likely to favour in-house investment, or use subsidiary firms, rather than follow a competitive procurement process.

1.3 There were also concerns identified around:

(a) access to information on network congestion and on the visibility of DER for both distributors and flexibility traders;

(b) obstacles for parties negotiating agreements for the provision of flexibility services;

(c) capability and capacity of the electricity industry to transform the distribution networks from delivering a predominantly uni-directional flow of electricity, to accommodating more distributed generation and two-way flows of electricity;

(d) electricity supply standards concerning the connection of DER – both in terms of connection times and additional standards that might be needed to address a range of power quality issues associated with increased competition and participation in the flexibility market.

1.4 A range of submissions from stakeholders were received, and in March 2022 the Authority circulated a survey to distributors and flexibility service traders to confirm the views on whether the above issues were a fair reflection of the consensus in the industry.

1.5 The results of that questionnaire and the subsequent engagements with stakeholders have been combined with the original discussion paper to produce this issues paper.

1.6 Analysis has also been informed by the work carried out by the Authority’s Innovation and Participation Advisory Group (IPAG), especially their Equal Access and Access to Input Services advice and their Review of the Transpower Demand Response Programme.

[1] Technologies used to generate, store, or manage energy are referred to as distributed energy resources (DER). DER are smaller–scale devices that can either use, generate, or store electricity and form a part of the local distribution system that primarily serves homes and businesses. DER can include renewable generation, energy storage, electric vehicles (EVs), and technology to flexibly manage loads (such as water heaters or pool pumps) at the consumer’s premises. Generation or storage DER operate for the purpose of supplying all or a portion of the customer’s electrical load and may also be capable of supplying power into the system or alternatively providing a load management service for customers. DER can also include front-of-meter small generation or storage located in lower-voltage parts of the network.

1.7 This issues paper largely confirms the range of issues identified in the discussion paper, but adds some perspective on the prioritisation of concerns and the urgency of dealing with these. The issues paper contains tentative options related to the most pressing issues for consultation with stakeholders.

1.8 The approach in this issues paper has been one of “least regrets”, in other words taking actions that would promote competition and efficiency regardless of how the emerging market for flexibility services develops in future. Therefore, the Authority seeks to encourage the provision and implementation of flexibility services without precluding distributors from these activities at this stage, in case that stifles the development of the market.

1.9 Nevertheless, the Authority proposes to leverage information collected by the Commerce Commission in terms of its Information Disclosure regime, to monitor the extent to which distributors are implementing non-network solutions, and whether they are using competitive procurement to do so. If it appears distributors are holding back the growth of the flexibility services market, the Authority could consider using its arm’s-length rules to encourage competitive procurement to boost the development of the market.

1.10 In relation to data, the Authority is confident there are some measures that can be undertaken without delay, such as amending the Data Template to speed up access to data. The purpose of the Data Template is to provide distributors access to Consumption Data on default terms provided by the Authority unless parties agree to a contract for sharing this data under alternative terms. It is critical at this point to ensure distributors and third parties have the data on network congestion and DER visibility to help them decide where to offer flexibility services.

1.11 The Authority has also considered the work of the UK Energy Data Taskforce and whether some of its recommendations could be applied in New Zealand. The Authority proposes to commission two separate reviews to look into the merit and practicalities of implementing the recommendations of the UK’s Energy Data Taskforce around unlocking the value of customer actions and assets and delivering interoperability in a New Zealand setting.

2 Introduction

Transition to low emissions and the role of the Authority

2.1 The New Zealand Government has a goal of net zero emissions by 2050. The electricity industry has a critical role to play in decarbonising the wider energy system, but the pace of change will present difficulties around reliability of supply and societal inclusion.

2.2 New Zealand needs to have the right amount of renewable electricity supply in the right place and at the right time to support an efficient transition to a low emissions economy, while maintaining security, reliability, and affordable electricity for all consumers. Investment in traditional network upgrades can now be delayed or replaced by implementing flexibility services, or non-network solutions (NNS)[2], but optimal market settings are required to maximise their potential.

2.3 The Authority's statutory objective[3] is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers. In this context, our independence as a regulator is valuable for promoting high performing electricity markets, reducing the risk of political intervention, and increasing predictability in how the regulatory regime operates. This is important for sectors like electricity that are technically complex and rely on long-lived, capital-intensive investments. Even though this means we give advice and are independent of government policy, we are attuned to the external environment in which we operate and the Government's key priorities.

2.4 To support the transition to a decarbonised and more de-centralised electricity system, we recognise that our role and the way we deliver our objectives must evolve. Therefore, the Authority wants to ensure our market and regulatory systems are fit-for-purpose and that we are ready to adopt new technologies to assist in the transition to a low emissions economy.

The Authority's vision for distribution networks

2.5 Distribution networks have a critical role to play in supporting New Zealand's transition to a low-emissions economy as they must transmit the greater amounts of electricity that will be demanded with electrification for decarbonisation. Distribution networks must also accommodate the growth of Distributed Generation (DG),[4] which depends on technological development and consumer behaviour. Traditional trends in both demand and supply are breaking down but distributors must anticipate both to avoid network bottlenecks as we decarbonise.

2.6 The Authority has a vision for distribution networks guided by our statutory objective and Government's goal for a more productive, sustainable, and inclusive economy, that improves the well-being and living standards of all New Zealanders.[5]

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[2] In this paper we use the terms flexibility services and non-network solutions almost interchangeably, although a non-network solution can be a package of flexibility services.

[3] The additional objective of the Authority comes into force on 31 December 2022 and is aimed at protecting the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers. Material from the amendment's passage indicates that Parliament's intention is for the additional objective "to come into play only when the Electricity Authority is considering the conduct of retailers and other participants that deal directly with small consumers, where there is an imbalance of power in those relationships that can result in adverse outcomes for small consumers". The Authority will continue to explore how this additional objective impacts its distributions networks programme of work on a case-by-case basis.

[4] Distributed generation (DG) is any form of generation connected to a distribution network, whether directly or indirectly via a consumer's electrical installation. Solar photovoltaic (solar PV or just 'solar') is the fastest-growing type of DG.

[5] See https://www.mbie.govt.nz/assets/discussion-document-accelerating-renewable-energy-and-energy-efficiency.pdf

2.7 Our vision for distribution networks is to support innovation, promote competition and consumer choice in contestable markets such as flexibility services, and maintain reliability and security of supply.

2.8 Distribution networks must develop to accommodate rising electricity demand, as well as bi-directional flows, creating new safety and technical challenges. This will make the task of operating them and maintaining reliable supply more complex.

Regulatory settings must maximise the value of new technology

2.9 Ensuring the right regulatory settings are in place to promote competition and access to the distribution network is crucial to support a rapid transition to a low emissions economy. The right regulatory settings are also needed to unlock the potential of new technologies and new investments for the long-term benefit of consumers.

2.10 The Authority is grappling with complex topics that have not yet been fully fleshed out. Therefore, it is important to follow a robust policy process to identify perceived issues and the potential for missed opportunities.

2.11 The Authority is also mindful that the system is constantly evolving. This has a dual impact on the Authority's work as proposed changes must be supported by evidence and be flexible enough to accommodate technological change and market development.

Purpose and structure of the consultation paper

2.12 This paper builds on the feedback received on the *Updating the Regulatory Settings for Distributions Networks* discussion paper released in 2021.[6] The purpose of the *2021 Discussion Paper* was to better understand stakeholder views and collect evidence on the potential issues and opportunities related to distribution networks.

2.13 The submissions[7] were helpful, but there were some conflicting views, so we decided more evidence was needed about the existence and scale of the issues.

2.14 Therefore, after the consultation process the Authority had several follow-up engagements with stakeholders, and sent an information request to all distributors, some retailers, and some Metering Equipment Providers (MEPs). The Authority's view of the issues and opportunities in this paper is based on submissions on the *2021 Discussion Paper*, follow-up engagements, and responses to the information request.

2.15 The analysis in this paper has also been informed by the work carried out by the Authority's Innovation and Participation Advisory Group (IPAG), especially their *Equal Access and Access to Input Services* advice and their *Review of the Transpower Demand Response Programme*.[8]

2.16 We have also looked into the work of the UK Energy Data Taskforce and whether we could apply some of its recommendations in New Zealand. The Taskforce was tasked with investigating how the use of data could be transformed across UK's energy system. The Taskforce produced, amongst other things, a report in January 2022 containing recommendations on how the energy sector can further enhance its digital activities, including unlocking value of customers assets and action through embedding a digitalisation culture.[9]

2.17 Now, the Authority seeks feedback on the issues and opportunities related to distribution networks that if addressed would help unlock the potential of Distributed Energy

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[6] https://www.ea.govt.nz/assets/dms-assets/28/Updating-the-regulatory-settings-for-distribution-networks.pdf
[7] Consultations — Electricity Authority (ea.govt.nz)
[8] IPAG Access to Input Services 2021; IPAG Equal Access Advice 2021: Transpower-DR-programme-review-draft-memo.pdf (ea.govt.nz)
[9] https://esc-production-2021.s3.eu-west-2.amazonaws.com/2022/01/ESC-Energy-Digitalisation-Taskforce-Report-2021-web.pdf

Resources (DER) for the long-term benefit of consumers. The Authority's focus on DER is explained in the next section, *The Potential of Distributed Energy Resources*.

2.18 The Authority wants to understand:

(a) whether the right issues and opportunities have been identified;

(b) what issues and opportunities should be prioritised; and

(c) whether there is more evidence on the issues and opportunities to be addressed.

2.19 The Authority has identified issues where there is enough evidence to support intervention that is needed now. This paper focuses primarily on the short-term changes needed. In the context of the electricity distribution sector, and for the purposes of this paper, we regard the short term as the next five years, the medium term as five to ten years, and the long term as ten years or more. The Authority has limited resources, and there is greater uncertainty about what changes might be required, and what their priority might be, the further out into the future we look. However, given the number and extent of changes that will ultimately be required, the approach of focusing on short-term changes now will only work if we commit to continuing to work in this area, so that new issues which emerge are addressed in a timely manner.

2.20 For the issues addressed in this paper, we have included options to address the issues, indicating our tentatively preferred options and asking for your views on them. Unless otherwise noted, there will be additional consultation before any option is implemented, which will include an options assessment and a cost-benefit analysis.

2.21 This paper has six chapters. The introductory chapter discusses the significance of new technology, especially relevant to DER and their role for the future of the electricity system in New Zealand. The next five chapters build on the themes in the *2021 Discussion Paper:* data; market settings; agreements; capability and capacity; and standards. The focus in some places has changed since the 2021 paper. Each chapter poses questions for stakeholders on each theme. Instructions for making a submission are set out in Appendix A.

2.22 Submissions on options that fall within the jurisdiction of another government agency (for example, those that come under the Commerce Commission's jurisdiction), will be shared with the relevant government agency. However, other government agencies have their own review processes, including consultation processes, so any submissions on options that fall within their jurisdiction should also be raised in those processes.

2.23 Whilst we have included definitions of certain terms for the purposes of this paper, these are not intended to be prescriptive, as there is limited consensus over some terms (eg, what is a DSO,[10] or what is included in DER) and because it may take time for a common understanding of the relevant terminology to take hold. Some definitions have been borrowed or developed from a range of sources such as IPAG's *Review of the Transpower Demand Response Programme*, and the FlexForum's *Flexibility Plan 1.0*.[11]

Feedback will be used to confirm and prioritise the issues identified

2.24 The Authority wants to form a clear picture of the challenges the distribution sector faces, to support the electricity distribution businesses (EDBs or distributors) as they strive to develop their networks and operations in this period of disruptive change.

2.25 Where the need for regulatory change is uncertain, interventions should be outcome-focused rather than prescriptive. The Authority wants to manage risk, remove barriers to market development, and create an enabling environment, rather than predetermine who should or should not do what. The Authority wants to stimulate the

[10] See tentative definition in Chapter 4, Option 5.

[11] https://www.araake.co.nz/projects/flexforum/

uptake and best use of DER. We should like to preserve optionality and adopt measures that are likely to have positive outcomes, regardless of how the markets for flexibility services develop (so-called 'least-regrets' measures).

2.26 The Authority plans to work with stakeholders to monitor[12] developments in generation and the distribution networks, and the rapidly evolving DER landscape. We aim to publish a paper in the first half of 2023 confirming the important issues and outlining a work programme to deal with them.

The Authority's Future Security and Resilience project

2.27 The Authority has released a final report into opportunities and challenges to the future security and resilience of the electricity system. The multi-year Future Security and Resilience (FSR)[13] workstream is investigating challenges and opportunities to maintaining a secure, stable, and resilient power system in the face of technological and other changes.

2.28 The initial focus of the FSR workstream is on addressing the challenges and opportunities across the broader transmission network. This includes issues such as system strength, and wholesale ancillary services, that impact New Zealand's electricity network at a regional or national level. This clearly overlaps with the role of DER, which can provide services to distribution networks, but also to Transpower or the system operator (eg, ancillary services, such as instantaneous reserve or frequency keeping). The effective aggregation and coordination of many smaller DER is an important factor in realising this opportunity. The Authority will ensure consistency and cohesiveness between its different workstreams addressing the transition.

The Authority is working closely with other relevant agencies

2.29 Addressing some of these issues and opportunities will require co-ordination with other government agencies to make the most of the complementary tools they have available.[14] The Authority has identified three areas of work within the wider government that clearly have flow-on impacts that will affect expenditure, innovation and behaviour in the sector:

a) the Commerce Commission's *targeted Information Disclosure Review and Input Methodologies Review* include areas relating to incentives and innovation in response to the changing economy as part of the broader aims of the projects

b) the Government Investment in Decarbonising Industry fund (GIDI fund),[15] which involves funding of around $650 million from the Climate Emergency Response Fund (CERF). The Energy Efficiency and Conservation Authority (EECA) administers the GIDI fund on Government's behalf

c) the Ministry of Business Innovation and Employment (MBIE) work, which is considering a proposal to amend the Energy Efficiency and Conservation Act 2000 to allow EECA to regulate the demand response[16] performance of energy-using products.

[12] Likely closely aligned or part of the Future Security and Resilience work programme of investigations.
[13] https://www.ea.govt.nz/assets/dms-assets/29/FSR-Phase-2-draft-roadmap-Discussion-Paper.pdf
[14] Appendix B: The complementary jurisdictions of the Commerce Commission and the Electricity Authority
[15] The objectives of the GIDI fund are accelerating business decarbonisation to support the Government's emissions reduction goals, optimising energy use by New Zealand's businesses, easing the transition and helping improve productivity, and helping achieve a just transition to renewables.
[16] Demand response normally refers to a consumer reducing their electricity demand at times of high energy system utilisation (peak demand), supply constraints or high prices, typically in return for a contracted financial reward.

The Authority acknowledges the valuable industry-led work that is going on

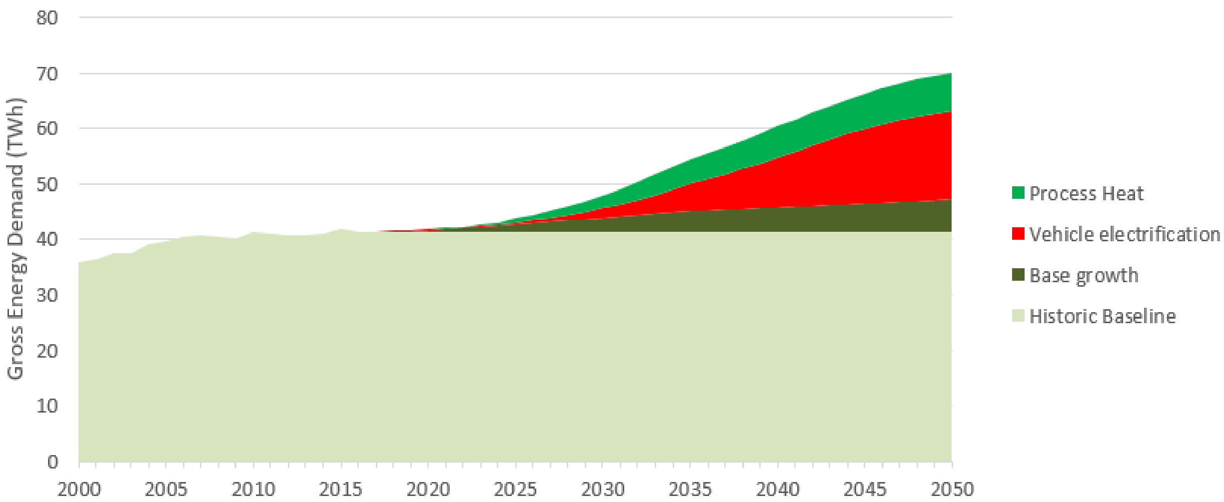
2.30 The Authority acknowledges the valuable work that is being driven by industry which will help unlock the potential of DER such as the work being carried out by the FlexForum[17] and the South Island Distribution Group.[18] The Authority also acknowledges the relevant work being carried out by the Electricity Network Association (ENA), in particular its Network Transformation Roadmap.[19] The Authority will continue to stay involved and engaged with this work. Transpower has also recently published its thoughts on flexibility.[20]

The Potential of Distributed Energy Resources

Transition to a low emissions economy impacts the electricity sector

2.31 The transition of New Zealand to a net-zero emissions economy will require the decarbonisation of the electricity industry and the wider economy. Figure 1 illustrates that gross electricity demand has been reasonably stable over the past two decades, but it is projected to increase significantly from 2025, driven by the electrification of transport and process heat. New Zealand's electricity demand is projected to be 68% higher in 2050 than 2019.[21]

Figure 1: Projected New Zealand electricity demand to 2050[22]



The rise of DER

2.32 As already noted, distribution networks will need to deliver much of the projected increase in demand for electricity. A challenge for distribution networks will be accommodating the increasing demand at the pace required, and in a cost-effective way. For example, Wellington Electricity estimates that energy consumption on it's network will increase by around 80% by 2050. It estimates that if it uses traditional methods to

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[17] https://www.araake.co.nz/services-projects/flexforum
[18] PowerPoint Presentation (ea.govt.nz)
[19] Transformation Update | ENA
[20] Enabling distributed flexibility to support whole system reliability and efficiency: a system operator view
[21] TP Whakamana i Te Mauri Hiko.pdf (transpower.co.nz)
[22] Source: D. Reeve, C. Comendant and T. Stevenson (2020) *Distributed Energy Resources – Understanding the potential*, A Sapere report for Transpower, July 2020 Distributed Energy Resources - Understanding the potential - main report - final_0.pdf (transpower.co.nz). Source data taken from Transpower's Whakamana i Te Mauri Hiko report ('Accelerated Electrification' scenario) p23: TP Whakamana i Te Mauri Hiko.pdf (transpower.co.nz)

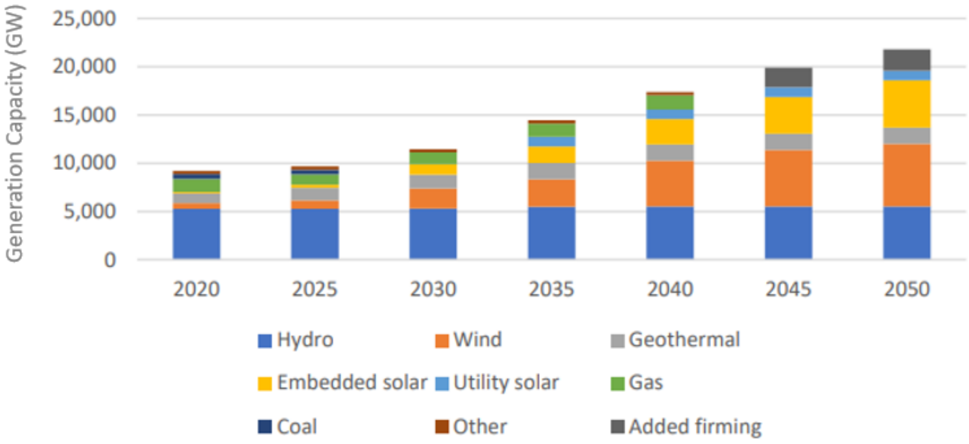
add the required network capacity, the costs would be around $1 billion, increasing the network line charges to consumers by around 80%.[23]

2.33 DER has the potential to contribute to the transition, by providing a range of benefits to households, businesses, distribution and transmission networks, and the electricity market. For example, consumers can use DER to lower their energy costs by generating some of their own electricity and shifting some of their consumption to periods when electricity is cheaper. Distribution and transmission networks can use DER to reduce network costs.

2.34 DER uptake in New Zealand has been slower than in other countries such as the USA, UK, or Australia. However, the use of DER in New Zealand is increasing, and significant growth is expected in the future. Figure 2 below shows a projection for generation capacity by type to 2050. It predicts significant growth in solar over time. This means New Zealand has an opportunity now, to get the settings right to maximise the uptake and the value that DER can provide.

2.35 We are also witnessing a rise in Distributed Generation (DG) applications to connect to the distribution networks. Even though most applications are for <20 kW (see Figure 3), distributors have received a number of large-scale solar applications in the last three years, resulting in significant growth in solar capacity. This trend is expected to continue.[24]

Figure 2: Projected New Zealand electricity generation capacity by source[25]

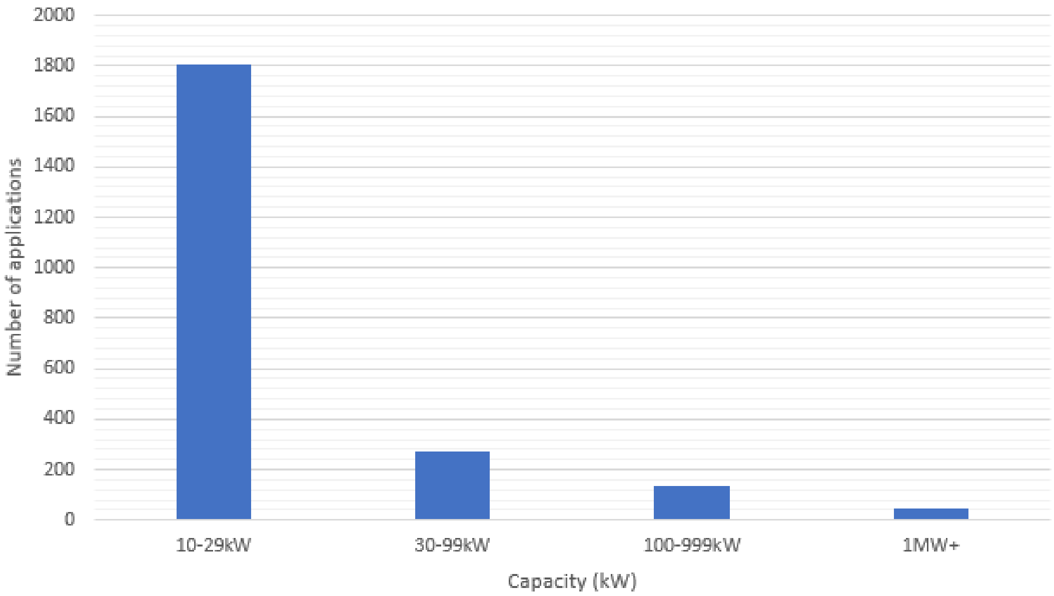


[23] Wellington Electricity EV Connect Consultation Roadmap, June 2022: [EV-Connect-Draft-Roadmap.pdf(welectricity.co.nz)]

[24] For more data around solar energy generation please see Chapter 6 .

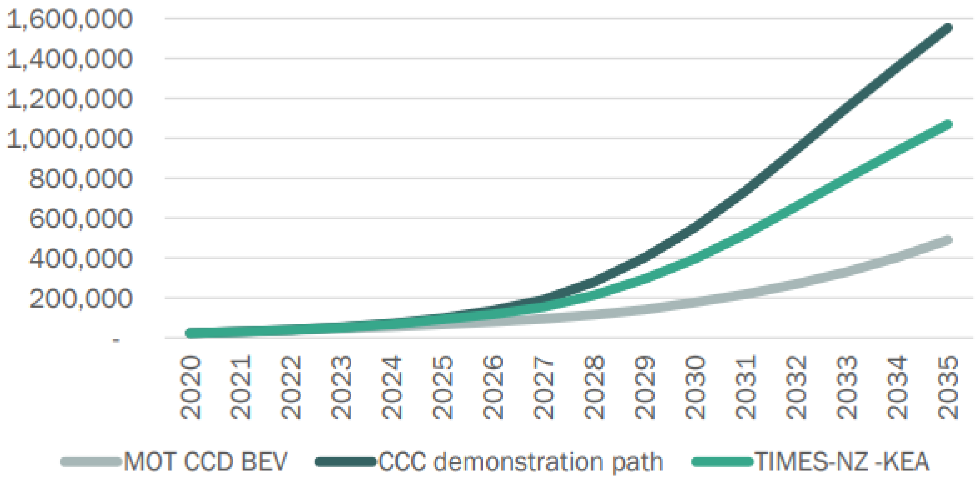
[25] Source: D. Reeve, C. Comendant and T. Stevenson (2020) *Distributed Energy Resources – Understanding the potential*, A Sapere report for Transpower, July 2020 Distributed Energy Resources - Understanding the potential - main report - final_0.pdf (transpower.co.nz). Source data taken from Transpower's Whakamana i Te Mauri Hiko report ('Accelerated Electrification' scenario)

Figure 3: Capacity of solar applications >10kW in New Zealand (Mid 2019–Mid 2022)[26]



2.36 There will also be sustained growth in the numbers of electric vehicles (EVs) on New Zealand roads over time. The Clean Vehicles Act 2022 imposes fees on high-emissions vehicles and makes rebates available for low-emissions vehicles. The Act also sets an average emissions target for vehicle importers, with fees payable if those targets are not met. Globally, many vehicle manufacturers have announced dates by which they will stop manufacturing new petrol or diesel cars. EV uptake forecasts from several New Zealand Government sources are included in the chart below (Figure 4).

Figure 4: Battery electric vehicle uptake scenarios 2020-2035 (excludes plug-in hybrid electric vehicles)[27]



[26] Source: EA information request 2022

[27] Source: Energy Efficiency and Conservation Authority (2022) *Improving the performance of electric vehicle chargers*, Wellington, New Zealand, a green paper by the Energy Efficiency and Conservation Authority https://www.eeca.govt.nz/assets/EECA-Resources/Consultation-Papers/EV-charging-Green-Paper-8-August-2022.pdf

Controllable DER provides flexibility for networks and benefits consumers

2.37 Controllable DER[28] can provide flexibility by modifying generation and/or consumption patterns in reaction to an external signal (such as a change in price) to provide a service within the energy system.[29] For example, water heating or EV charging could adjust or turn on and off in response to signals based on electricity prices. Flexibility services will play an increasingly important role in the electricity system.

2.38 The flexibility available from controllable DER can reduce the need for thermal peaking in the electricity market and offset the need for new lines investments and generation. It can also contribute to ancillary services including instantaneous reserves and voltage support. A cost-benefit analysis undertaken by Sapere estimated that if DER were to realise its potential, the net benefit from 2021 to 2050 would be $6.9 billion. These benefits are additional to the benefits expected to occur from DER under the current market and regulatory environment.[30] These savings will ultimately be passed on to consumers.

2.39 According to the Sapere cost-benefit analysis the main benefit of flexibility from controllable DER is deferring network build and generation capital expenditure, which is estimated to achieve a net economic surplus of $5.9 billion (85.86% of the total potential benefits of $6.9 b, see Table 1). The benefits estimated by Sapere are all stated as consumer benefits, whether received as increased consumer surplus ($2.8 b) in the form of lower prices, or in the form of producer surplus ($4.1 b), whereby consumers as owners of DER (ie, prosumers) are able to earn revenue on electricity generated, for themselves and others. [31] We agree with the implicit assumption that benefits which accrue to distributors will largely pass through to consumers because of the regulated environment they operate in.

Table 1. Estimates of net economic surpluses by DER value streams, net present value 2021-2050 (reproduced from: Sapere [32])

	$ billion, NPV	**% total**
Resource adequacy – offset thermal peaking	$0.347	5.06%
Resource adequacy – offset new lines and generation	$5.9	85.86%
Hydrofirming	$0.624	9%
Instantaneous reserve	$0.0007	0.01%
Voltage management	$0.005	0.07%
Total economic surplus	**$6.9**	**100%**

2.40 As illustrated by Figure 5, if new demand is shifted to less congested periods, substantial network investment could be deferred. The key to managing future demand is

[28] Controllable DER – DER whose output or consumption can be turned up or down on demand – for example, diesel generation, batteries, and controllable EV chargers, but not intermittent renewable generation like wind or solar. The Impact of controllable DER is flexibility

[29] This is the definition of flexibility developed by OFGEM and adopted by IPAG.

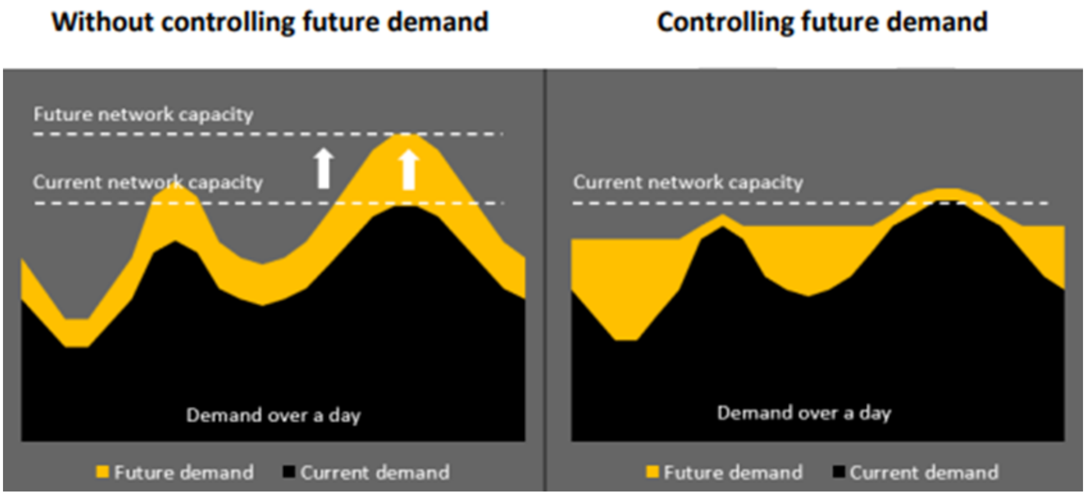
[30] D. Reeve, T. Stevenson & C. Comendant (2021) *Cost-benefit analysis of distributed energy resources in New Zealand: A report for the Electricity Authority*, Wellington, New Zealand Cost-benefit-analysis-of-distributed-energy-resources-in-New-Zealand-Sapere-Research-Group-final-13September.pdf

[31] Ibid., Table 1, p vii.

[32] Ibid., p 25.

developing the flexibility services that use consumer DER to move electricity consumption away from congested periods on the network. There are many other flexibility services that controllable DER can provide.

Figure 5: Controlling vs. not controlling future demand[33]



A staged approach to realise the benefits of DER

2.41 For the public benefits of distribution-embedded DER to be realised there are some fundamental requirements (noting that long-term issues in particular may not arise, or be addressed, in the way imagined now):

- facilitate equal access to data for competing participants
  - in the short term (the next five years), sufficient samples of ICP-level, historic consumption and power quality data are required to facilitate decisions on whether and where to invest in NNS
  - this data would provide visibility of DER on the LV network and is needed to indicate headroom / congestion of the network in order to optimise DER hosting
  - in the medium term (the next five to ten years), meter data including consumption and power quality data will be needed that is either real-time or progressively more frequent, more granular, and with increasing sample size. Data will also increasingly be available for use from EVs, EV chargers, and household appliances
  - in the long term (more than ten years ahead), real-time data from meters and many other sources will be available and necessary to facilitate the monetisation, dynamic pricing and exchange of flexibility services across value streams
- in the short to medium term, ensure that distributors and flexibility traders are sufficiently and equally incentivised to enter into or expand within the flexibility services market
  - As the Sapere report (p8) pointed out, "some services, such as instantaneous reserve (IR), could be relatively easily opened to suitable DER, but other services would require significantly more coordination and incentives"

[33] Source: [EV Connect (welectricity.co.nz)](welectricity.co.nz)

- facilitate the emergence of appropriate market arrangements for the exchange of flexibility services
    - in the short term, facilitate contracting and procurement of flexibility services, between distributors and flexibility traders
    - in the medium term, facilitate market design and the formulation of flexibility service product types[34], as the numbers of buyers and sellers rise and as bilateral contracts become inefficient
    - in the long term, facilitate the emergence of neutral trading platforms on which many buyers and sellers of flexibility services will be able to trade defined products based on dynamic (real-time) pricing signals. Note that it is mainly demand-side responses to price signals that must be developed, because wind and solar generation do not respond to price signals. Demand-side actions require digital tools to manage and access.
- facilitate the uptake of DER by consumers and businesses, especially the uptake of EVs plus EV chargers, and solar panels plus batteries

2.42 The five areas of focus in this paper can all contribute to realising these requirements. For example, a sensible approach to standardisation will make more DER available, maximise its contribution to the value stack, and contribute to a level playing field. Changes in market settings could also promote a level playing field and thereby enable the monetisation of all potential DER value streams, and improvements in access to data contributes to visibility of DER and opportunities to use them to maximum effect.

2.43 The Authority envisages that when the market is fully developed (which will take several years) this should see flexibility services being offered by many sellers to many buyers, serving the full 'value stack'.[35] In terms of sequencing, the Sapere report predicted the following availability of DER at three points in time, 2021, 2035 and 2050: [36]

(a) 2021: demand response, EV batteries and PV (solar) systems – of these three technologies that are now economic, EV chargers are not yet practically available

(b) by 2035, many DER technologies are cheaper than building new lines and generation or thermal peaking. DR becomes the cheapest technology and can possibly offset the need for new lines and thermal peaking capacity, whilst major contributions are expected from EV chargers, PV plus batteries and EV batteries paired with PV installations. Smart technology becomes common, and there should be widespread use of inverter-controlled compressors for heating, cooling and refrigeration, so that automated smart homes present a stable maximum load for the most part; and

(c) by 2050, PV and battery installations are expected to be almost economic without accessing any value other than self-supply; DR is still the cheapest way of offsetting new peaking generation, transmission, distribution and some hydrofirming. EVs are cheap DER but cannot make a marginal contribution to hydrofirming unless paired with PV; and PV installations with batteries could contribute significantly to hydrofirming if the pricing is right (somehow rewarding the capacity for its periodic availability whilst ensuring the surplus it delivers at other times does not drive spot prices below the cost of operation and maintenance). Harmonics expected to be a problem by 2050 which will require

[34] For example, the Common Evaluation Methodology document produced for the UK Energy Networks Association (see https://www.energynetworks.org/assets/images/Resource%20library/ON20-WS1A-P1%20Common%20Evaluation%20Methodology-PUBLISHED.23.12.20.pdf) suggests only four flexibility products: 'sustain', 'secure', 'dynamic' and 'restore'.

[35] See Figure 6

[36] Reeve, Stevenson & Comendant, 2021, op. cit. p21-23.

incentives for inverters with low harmonic distortion or the provision of filtering stations.

2.44 In practice, the new services offered will accommodate bi-directional (two-way) power flows that will allow consumers to sell the value of their excess energy to other users or sell the deferral of their energy consumption in times of network congestion.

Unlocking the potential of controllable DER and flexibility services for the benefit of consumers

2.45 In the near future, consumers (households and businesses) will own increasing levels of controllable DER that will have the potential to provide a range of flexibility services.[37] For consumers to be able to receive the full benefits of controllable DER and flexibility services, they will need to allow electricity sector participants such as flexibility traders[38] access and control of the DER located inside their homes and businesses.

2.46 The Authority envisages fostering a regulatory environment where consumers trust flexibility traders or other participants and can make informed decisions to allow them to manage their DER. An example of a trial to shift EV charging times in the UK showed that to access the desired flexibility of controllable DER it is best to make the process simple and automated for consumers.[39]

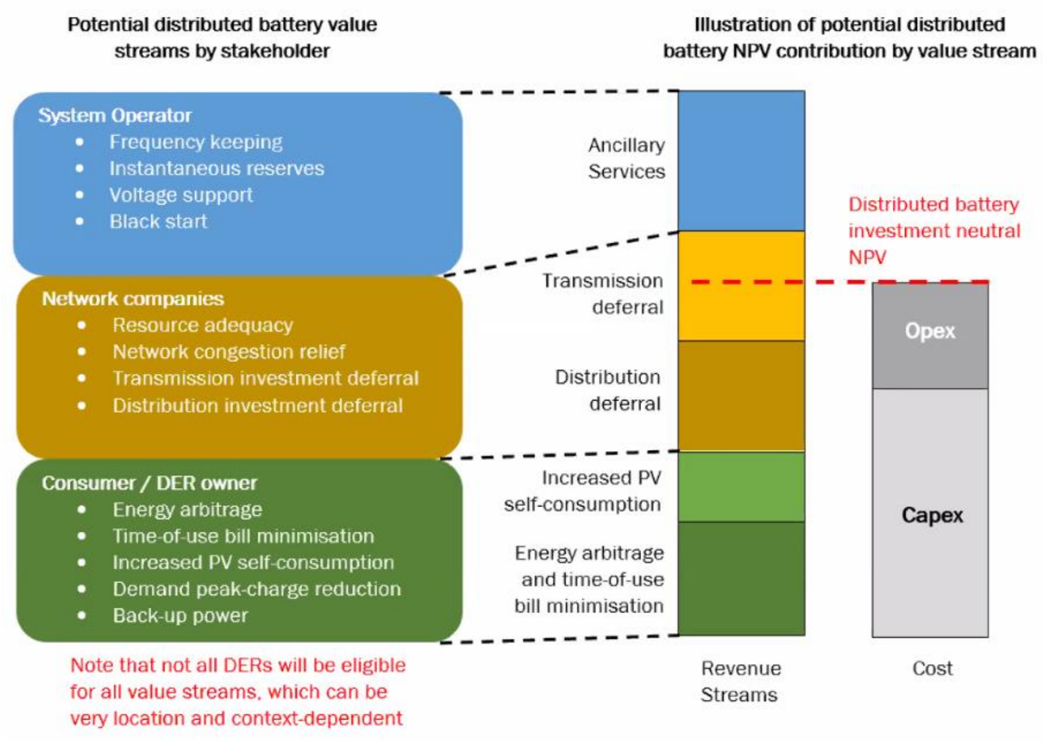
2.47 To meet the needs of current and future energy consumers, users and stakeholders, and to unlock the potential of controllable DER, all revenue streams in the value stack should be accessed (see Figure 6). The more value streams are available to be served by DER, the greater the benefit will be and the greater the uptake will be. Figure 6 is an illustrative example of the potential for solar PV plus battery to serve components of the value stack and in return, access the relevant revenue streams, although increased self consumption is a saving rather than a revenue stream.

[37] A key example of this kind of DER is smart EV chargers, but other appliances are likely to emerge including space heating. Externally-controllable batteries linked to solar PV are already in use. Domestic hot water is a form of legacy DER when subject to ripple control, and emergent forms of technology could be used going forward. A range of industrial and commercial electrical plant can be externally controlled.

[38] Owners of DER portfolios (not necessarily owners of the DER themselves) who manage these portfolios to allocate DER to their highest value uses. Flexibility Traders interact with flexibility buyers and the providers of DER to provide the flexibility services required. In time, flexibility traders will maximise the value of DER by allocating them to their highest value use in the 'value stack' rather than restricting DER to one use.

[39] UKPN_Shift_Interim_Report_v05.pdf (ukpowernetworks.co.uk)

Figure 6: Flexibility value stack



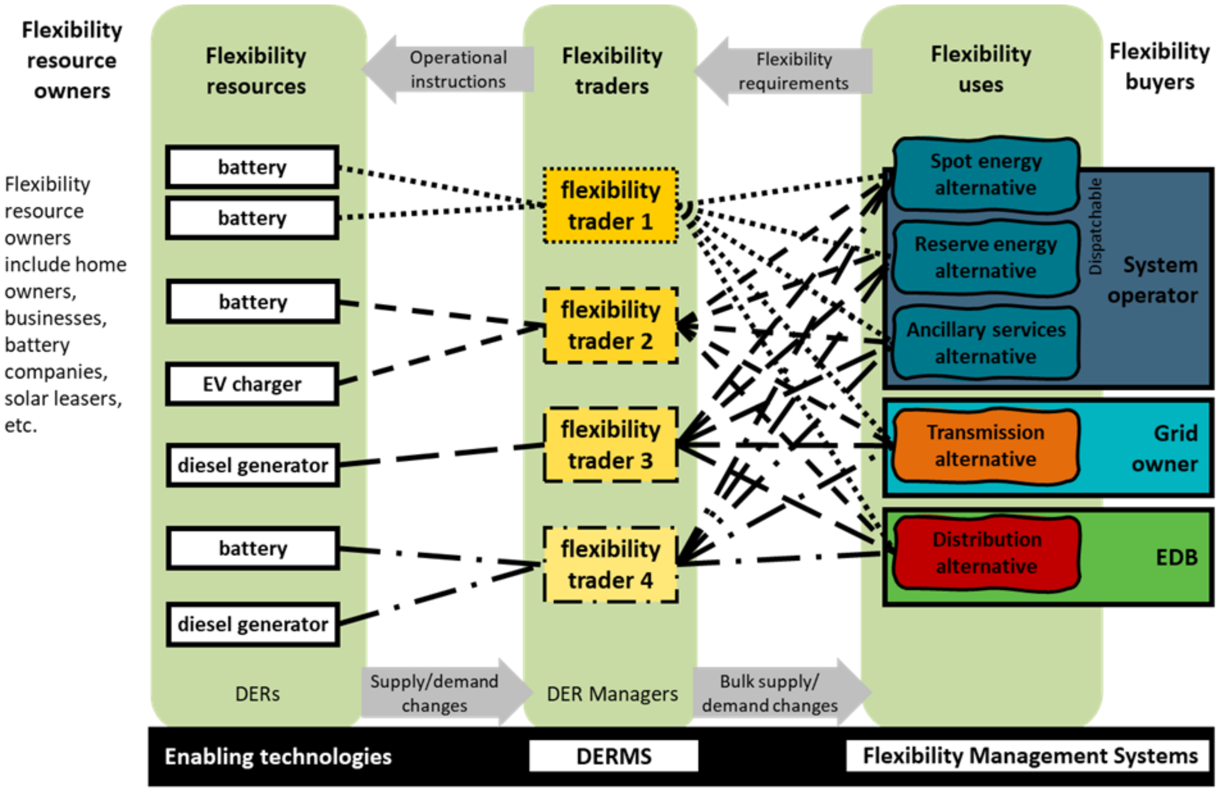
2.48 In addition to the value opportunities identified above, others may emerge. For example, the following participants may wish to encourage domestic consumption to move from peak to off-peak periods:

- intermittent generators (wind, solar)
- retailers, at times when the spot price they pay exceeds the price at which they sell to their customers
- operators of industrial equipment on capacity-constrained parts of the network which may otherwise need to throttle their production.

2.49 The Authority recognises that there can be different approaches around how government and industry can support choices for consumers on how to use their controllable DER to realise the greatest value for them from the flexibility value stack. There could also be a variety of pathways in terms of matching electricity demand with DER, which in turn might be co-ordinated by either distributors or flexibility traders, and perhaps using DER management systems, or DERMS. IPAG's vision of the future state of 'Flexibility Markets'[40] is shown in Figure 7. IPAG has expressed the view that flexibility traders should play the market-making role rather than 'smart' distributors, which could be conflicted in that their own networks are part of the value stack.

[40] Flexibility markets – mechanisms for matching and rewarding traders of controllable supply and/or demand on instruction or in response to prices.

Figure 7: Flexibility markets – clarification of terminology and roles[41]



Distributors and flexibility traders are key to maximising the value of DER

2.50 Distributors have a major role to play in unlocking the potential of DER and flexibility services. They connect and integrate DER into their networks while maintaining reliability, and they buy flexibility services that are part of the value stack.

2.51 The 29 distributors in New Zealand are different in many respects and the Authority should guard against a one-size-fits-all approach. For example, smaller distributors might not have the capacity to provide their own flexibility services or to attract interest from third-party suppliers without collaborating with larger or adjacent distributors.

2.52 Several distributors stated in their responses to the information request that it is not appropriate for them to self-supply flexibility / NNS or to act as flexibility traders. This corresponds with the view of the Council of European Energy Regulators (CEER),[42] as well as IPAG.[43] In the UK, Ofgem in 2019 supported 'optionality' in continuing to allow distributors to provide their own flexibility services, recommending 'least regrets' measures such as enhancing access to data for all interested parties in the meantime.[44] However, from 2023 Ofgem will require distributors to procure flexibility services using market-based procedures, in terms of a new licence condition 31E, [45] which transposes

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[41] Transpower review of its DR programme https://www.ea.govt.nz/assets/dms-assets/28/Transpower-DR-programme-review-memo.pdf

[42] Council for European Energy Regulators, 22 March 2019. *New services and DSO involvement: a CEER conclusions paper.* Distribution systems working group. Ref. C18 DS46-08.

[43] IPAG, IPAG Equal Access Advice 2021

[44] Ofgem, 2019. https://www.ofgem.gov.uk/publications/ofgem-position-paper-distribution-system-operation-our-approach-and-regulatory-priorities

[45] Electricity Distribution Standard Licence Condition 31E: Flexibility Procurement Statements 2022 | Ofgem

Article 32 of the EU Directive 2019/944, the *Clean Energy for all Europeans Package (CEP)*.[46] Part of Article 32(1) says:

> "Distribution system operators shall procure such services in accordance with transparent, non-discriminatory and market-based procedures unless the regulatory authorities have established that the procurement of such services is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion."

2.53 Some distributors own and operate their own batteries, and this could increase in the future. There may be efficiency benefits to distributors owning and operating batteries. Equally, efficiencies could be available to third-party owners. If distribution networks own DER, the flexibility might be used exclusively for their distribution purposes rather than being available to other parts of the value stack.

2.54 The Authority is mindful of its statutory objective, and in particular the competition limb, when considering distributors' ownership and operation of DER, and the available flexibility should not be limited to benefiting distribution networks.

2.55 A flexibility trader could operate its own and consumer owned DER in a way that optimises its value, for example reducing electricity use when electricity prices are high. Alternatively, a flexibility trader could own and optimise the use of DER installed on a consumer's premises and charge the consumer a fee for that service.

2.56 Flexibility traders are presumed to have incentives to maximise the value of DER by allocating them to their highest value uses in the value stack, rather than reserving them for one use. Allocating DER to their most productive uses is key to encouraging investment in DER uptake.

2.57 The development of the flexibility services market is still in its early stages in New Zealand. It is important to ensure the market settings are in place to promote, and not to hinder, the development and commercial establishment of flexibility traders.

2.58 As the market is just emerging, we can learn from experiences observed in comparable markets, but it seems clear that any interventions at this point should be cautiously limited to 'least regrets' measures that will not create barriers for future development of the market. Therefore, the Authority wants to avoid developing prescriptive commercial and regulatory frameworks too early, which could constrain market growth.

2.59 However, the Authority would prefer to move at the speed of the fastest adopters, not the slowest, and be able to pick up pace as the market matures. Therefore, regulatory flexibility is needed to allow participants to test and develop new services without regulatory restrictions that impede their progress. There has also been some suggestion that the Authority ought to make a "regulatory sandbox" available to encourage innovation.

2.60 That said there are some foundational policy decisions the Authority needs to make in the next 12 months namely around:

- Regulating how and what kind of data MEPs provide to distributors and flexibility traders[47]
- The threshold that when crossed will lead the Authority to extend the current arm's length rules [48]

[46] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019L0944

[47] See the relevant discussion in the *Data and Information* chapter particularly around what data and information do distributors and flexibility traders need, and why (paragraph 4.53 onwards).

[48] See the relevant discussion in the *Market settings for equal access* chapter (paragraph 5.81 onwards)

- The scope of a Part 6 review including amending Part 6 of the Code to explicitly include DER[49]
- Mandate AS/NZS 4777.2:2020 Standard for inverters in New Zealand [50]

Regulatory clarity around the above-mentioned areas will afford the sector enough certainty to plan ahead and make the business decisions necessary for the future development of a flexibility services market.

3 What you need to know to make a submission

3.1 The Authority seeks feedback on the issues and opportunities related to distribution networks that if addressed would help unlock the potential of DER for long-term benefit of consumers.

3.2 The Authority wants to understand:

- whether the right issues and opportunities have been identified;
- what issues and opportunities should be prioritised; and
- whether there is more evidence on the issues and opportunities to be addressed.

3.3 The Authority has identified some issues where there is enough evidence to support some form of intervention. In these cases, we have included options to address the issues, indicating our tentatively preferred options and asking for your views on them. Unless otherwise noted, before we implement any options, we will produce a comprehensive options assessment and do more consultation.

How to make a submission

3.4 Our preference is to receive submissions in the format shown in Appendix B. Submissions should be emailed to distribution.feedback@ea.govt.nz with "*Issues Paper—Updating the Regulatory Settings for Distribution Networks*' in the subject line.

3.5 Please note the Authority wants to publish all submissions it receives. If you consider that we should not publish any part of your submission, please:

- indicate which part should not be published.
- explain why you consider we should not publish that part
- provide a version of your submission that we can publish (if we agree not to publish your full submission).

3.6 If you indicate there is part of your submission that should not be published, we will discuss with you before deciding whether to not publish that part of your submission.

3.7 However, please note that all submissions we receive, including any parts that we do not publish, can be requested under the Official Information Act 1982. This means we would be required to release material that we did not publish unless good reason existed under the Official Information Act to withhold it. We would normally consult with you before releasing any material that you said should not be published.

When to make a submission

3.8 Please deliver your submissions by 5pm on Tuesday 28th February.

3.9 We will acknowledge receipt of all submissions via email. Please contact the Authority info@ea.govt.nz or 04 460 8860 if you do not receive an email acknowledging your submission within two business days.

[49] See the relevant discussion in the *DER Standards* chapter (paragraph 8.14 onwards)
[50] See the relevant discussion in the *DER Standards* chapter (paragraph 8.87 onwards)

4 Equal access to data and information

Introduction

4.1 Ideally, New Zealand would have a fully digitised energy system in which key data could be seamlessly accessed and exchanged in real-time by authorised parties. Having open, transparent, and real-time data will be needed to unlock the full potential of DER. However, based on information provided by the sector, the Authority considers the most pressing need in the short term is to improve the visibility of the low-voltage (LV) network and improve access to smart meter data.[51] The Authority considers this to be a key step to reaching a fully digitised energy system.

4.2 Data requirements in the short term (the next five years) will likely be for samples of, say, month-old, ICP-level, daily consumption and perhaps power quality data. When combined with distributors' knowledge of their network capacities, this could indicate congestion, headroom, and the capacity for hosting DER. These insights should then be made available for distributors and flexibility traders to decide where and when to implement NNS.

4.3 In the medium term (the next five to ten years), the likely data requirements (from smart meters) will be consumption data and power quality data to facilitate the rising provision of NNS from many sources of DER. More frequent data collection and rising sample sizes will be needed to enable more precise and interactive provision and pricing of NNS, rather than pre-defined events triggering the dispatch of DER, based on bilateral contracts.

4.4 In the long term (beyond ten years) there should be progressive steps towards total network coverage with real-time data, to facilitate the operation of flexibility service trading platforms catering for many providers of flexibility services and many buyers of those services – distributors, system operator, Transpower, and retailers. Data sources would go far beyond smart meters, to smart EV chargers and other DER, and smart water cylinders and other smart household appliances.

4.5 The Authority wants to ensure equal access to data to create a level playing field. Distributors and flexibility traders will want and need the same information to unlock the potential of DER for the long-term benefit of consumers, but they might follow different paths to get there as they are starting from different places. Therefore, distributors and flexibility traders are considered separately, but the aim is that they have equal access to data.

4.6 As noted earlier, the potential net benefits of DER were estimated by Sapere at $6.9b for the period 2021-50. This potential will not be realised if the data needed is not available or there is unequal access to it. Data is the key to efficient network planning, management, and pricing strategies. Providing equal access to data will ensure that any business can compete on a level playing field to develop and offer products and services that will maximise the value of DER for the long-term benefit of consumers.

4.7 Table 2 lists issues related to access and availability of key data and information that, if addressed, would likely help distributors and flexibility traders take the first steps to

[51] It is possible that distributors and flexibility traders would get access to more of the data and information that they need through installing their own (metering) equipment. However, this could be a costly and inefficient solution if the data and information is already collected by existing smart meters (or smart appliances e.g., smart hot water cylinders and smart heat pumps).

unlock the potential of DER. We are seeking feedback on whether these are the key issues related to access and availability of key data, and how they should be prioritised.

4.8 Table 3 lists some possible options that the Authority is seeking feedback on now. The Authority is proposing to progress some of these options as soon as practicable, while some options will take more time develop, and some options are mutually exclusive. The Authority has explained where this is the case.

Table 2: Summary of the issues related to access and availability of key data in the short term[52]

Issues related to access and availability of key short-term data and information		Priority and target time to address[53]
1	Improvements to the Data Template[54] are required to enhance its workability.	High 1-5 years
2	For **distributors** to receive ICP Data for their distribution networks, multiple retailer permissions are often needed.	High 1-5 years
3	**Distributors** are not permitted to receive Power Quality Data in the same way as Consumption Data.	High 1-5 years
4	In addition to gaining retailer permission to collect ICP Data direct from the MEP (e.g., Consumption Data through the Data Template), the **distributor** also needs to negotiate an access agreement with the MEP.	High 1-5 years
5	MEP pricing for provision of ICP Data and other services to **distributors** (and **other parties**) is not transparent.	High 1-5 years
6	**Distributors** need better visibility of customer information on the location, size, and functionality of DER (non-exporting) on their LV network.	Medium
7	**Distributors** do not have access to 'real-time'[55] Consumption Data and Power Quality Data.	Low
8	**Flexibility traders** do not have equal access to ICP Data.	High 1-5 years
9	**Flexibility traders** do not have access to granular Network Congestion Data on LV networks.	High 1-5 years
10	**Flexibility traders** do not have visibility of information on the location, size and functionality of DER on LV networks.	Medium
11	**Flexibility traders** do not have access to 'real-time' granular congestion data or ICP Data.	Low
12	**Privacy Law** transparency requirements are sometimes perceived as a barrier to disclosing ICP Data.	High 1-5 years

4.9 Table 3 lists some possible options that the Authority is seeking feedback on now. The following explains how the options could sequenced and the relationship between the different options:

[52] The issues and analysis in this workstream have been informed by the IPAG's Equal Access and Access to Input Services advice. IPAG Access to Input Services 2021; IPAG Equal Access Advice 2021

[53] The data needs and issues in this workstream are prioritised based on what is most important at this stage to achieving the desired outcomes. This is a judgement based on the feedback the Authority has received. The Authority welcomes feedback on the prioritisation.

[54] Data Template means the template set out in Schedule 12A.1 Appendix C in the Electricity Industry Participation Code 2010.

[55] The Authority acknowledges that the definitions of 'real-time' vary. Ideally, this would be instantaneous access to data, but there will be intermediate steps before reaching this point, such as receiving half-hourly Consumption Data within hours of collection, and then 5-10-minute intervals.

(a) **option a) and c):** Subject to feedback the Authority is proposing to implement these options as soon as practicable.

(b) **the other options**: Before implementation, the Authority will consult further on their design. Feedback on the options will influence their prioritisation and design.

(c) **options d), f) and g):** If d) was implemented (amending the code to clarify that MEPs must provide ICP data to distributors and flexibility traders), this would likely eliminate the need to implement options f) and g) *(amending the data template for Power Quality Data and expanding it to flexibility traders)* as the Data Template would no longer be necessary to obtain Consumption and Power Quality Data.

Table 3: Options to address the short-term data issues raised in Table 2

	Description	Issue
a)	Amendments to the Data Template to improve its workability: • allow merging of data sets • default provision of Consumption Data is monthly • MEPs by default provide the Consumption Data • clarify that MEPs are only entitled to charge reasonable costs for providing Consumption Data.	1
b)	Review and update DER information requirements captured in the registry database, for example functionality and batteries.	10[56]
c)	The Authority provides model privacy disclosure terms for retailers to include in their terms and conditions or privacy notices.	12
d)	Amend the Code to clarify that MEPs must contract directly with and provide both Consumption Data and Power Quality Data to distributors and flexibility traders for a set of permitted purposes (ie, without the need for retailer permission).	2, 3, 8
e)	Require MEPs to publish standard 'pay-as-you-go' terms open to all parties (including 'rack rates' for standard meter services), which would include service schedules, terms and conditions, and pricing that allows costs for any given ICP to be determined – as recommended by IPAG in its Input Services advice.[57]	4, 5, 8
f)	Modify the Data Template so that it includes a requirement to provide Power Quality Data.	3
g)	Modify the Data Template so that flexibility traders can use it to obtain Consumption Data (and Power Quality Data if the Data Template is modified so that it includes a requirement to provide Power Quality Data as well).	8
h)	Commission two separate reviews studies to look into the merit and practicalities of implementing the recommendations of the UK's Energy Data Taskforce around unlocking the value of customer actions and assets and delivering interoperability	All

[56] This option would mostly go towards addressing issue 10 (flexibility trader visibility of DER) as distributors already have visibility of DER that is capable of exporting. Depending on the final design of this option, it could help address 6 (improve distributor visibility of DER) but that is to be worked through.

[57] IPAG's 2021 Input Services access advice: [PowerPoint Presentation (ea.govt.nz)](#)

	in a New Zealand setting. The Authority will consult on the studies' findings and proposals as appropriate. see **Box 1** (below).[58]	

Scope

4.10 This chapter considers the issues related to access and availability of key data and information which, if addressed would help distributors and flexibility traders unlock the potential of DER for the long-term benefit of consumers.

4.11 As mentioned earlier, it would be ideal for New Zealand to move to a digitised system with seamless access to, and exchange of real-time data by authorised parties. We envisage that seamless data exchange will eventually facilitate an energy system, which can accelerate, automate, plan, and anticipate processes to unlock the potential of DER and new technologies for the benefit of consumers. To that end we are also taking a closer look at the recommendations included in a report produced by the UK Energy Digitalisation Taskforce.

4.12 Based on information provided by the sector, the Authority considers the most pressing need is to improve the visibility of the low-voltage (LV) network and improve access to smart meter data. This would be a key step to reaching a fully digitised energy system.

Desired outcomes

4.13 The desired outcomes of this workstream are:

(a) distributors have the required data and information to make optimal investment planning, Power Quality management (including outage information) and network pricing decisions

(b) flexibility traders have the information they need to make informed business decisions and compete on a level playing field.

4.14 The overarching desired outcome is that all electricity industry participants have access to the data and information they need to make informed decisions that will support the transition to a low emissions economy and provide long-term benefits to consumers. This workstream is a step towards achieving this overarching outcome.

4.15 Distributors and flexibility traders are considered separately, but with the end goal in mind that they have equal access to data.

Distribution networks – what has caused the change in data and information requirements?

4.16 Distribution networks were designed when customer load was smaller and more predictable, and electricity flowed one-way. As the levels of uptake in DER such as solar panels, electric vehicles, batteries, and technology that can control consumption increase, customer load will become larger and less predictable and two-way power flows possible. Penetration of smart meters has also changed the amount of data that can be collected, and the cost and speed involved in collection, collation, and transfer.

Status quo

4.17 This part covers who collects what data, what mechanisms are in place to facilitate data sharing, and what the data needs are of distributors and flexibility traders, to maximise the potential of DER.

[58] Catapult-Energy-Data-Taskforce-Report-A4-v4AW-Digital.pdf (esc-production-2021.s3.eu-west-2.amazonaws.com)

Who collects what data?

4.18 This section outlines the data and information relevant to LV Networks that is currently collected and received by different MEPs, retailers, distributors, and flexibility traders.

Information collected by MEPs

4.19 Retailers select an MEP to provide the metering and data services they need to conduct their business with a consumer and this arrangement is governed by a commercial contract.

4.20 The data and information that an MEP collects at an ICP[59] level is initiated by what they are contracted to provide to the retailer. The information typically collected by MEPs is:

(a) half hourly and non-half-hourly Consumption Data

(b) outage information (when the power turns off at an ICP)

(c) alerts, such as tamper and reverse power flow alerts.

4.21 However, MEPs, through smart meters, have the capability to collect additional information that would provide greater insights into LV networks.[60] Though the information capability varies depending on the age and functionality of the smart meter, some additional information that smart meters collect or can collect include:

(a) more frequent Consumption Data, for example at five-minute intervals

(b) voltage per phase

(c) current per phase

(d) harmonics

(e) reactive power

(f) frequency

(g) last / first gasp (a notification from a meter upon loss / recovery of power)

Information collected by retailers

4.22 Depending on retailer needs, they will receive half-hourly or non-half-hourly Consumption Data from the MEP. Retailers also receive some alerts from MEPs, such as tamper and reverse power flow alerts.

4.23 Retailers collect customer information, such as names and addresses. When combined with the ICP level Consumption Data, this enables retailers to bill their customers.

4.24 Retailers also receive outage information from distributors, so they can inform their customers of outages, and billing information in Electricity Information Exchange Protocol (EIEP)[61] format.

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[59] ICP means an installation control point, being one of the following: (a) a point of connection at which the electrical installation for a retailer's customer is connected to a network other than the grid: (b) a point of connection between a network and an embedded network: (c) a point of connection between a network and shared unmetered load. Each ICP is assigned a unique identifying number.

[60] Around 83% of meters are smart meters (and around 93% of these are residential). They are on approximately 2.2 million ICPs. Smart meters can record more regular and more accurate electricity consumption information than older meters. They also have two-way remote communications and depending on the configuration, may have as near as possible real-time communications between the Services Access Interface (users receive and send information into the smart meter) and the metering point. The Authority's smart meter Guidelines, help promote functionality of new technology for metering: https://www.ea.govt.nz/assets/dms-assets/8/8573Guidelines-on-Advanced-Metering-Infrastructure.pdf

[61] Details for these EIEPs are on the Authority's website: Regulated electricity information exchange protocols (EIEPs) — Electricity Authority (ea.govt.nz)

4.25 There is also a significant number of ICPs where the meters are manually read by the retailer, not the MEP. This occurs for two main reasons:

(a) a smart meter may have been installed but is not remotely communicating with the MEP. This may be because of communication connectivity issues or customer request to remove the modem

(b) there is no smart meter installed.

Information collected by distributors

4.26 To calculate their fixed and variable network charges (which are invoiced to retailers, who then invoice customers), distributors receive a range of information from retailers via regulated EIEP. This information can include monthly Consumption Data at an ICP level, half-hourly Consumption Data at an ICP level (typically this is just for larger commercial electricity connections), and customer details including names, addresses and contact details.

4.27 Some distributors also collect a limited amount of information on their LV networks, such as outage information.

4.28 Distributors can also access Consumption Data from retailers (or directly from the retailer's MEP if the retailer permits or retailer's contract with the MEP otherwise allows), by submitting requests on the Data Template, which was introduced alongside the Default Distributor Agreement (DDA)[62] template in July 2020. Distributors can only use this information for permitted purposes,[63] which include developing distribution pricing, network planning and management of the network such as contacting customers in the event of outages and some network maintenance, such as tree trimming. The Data Template exchanged between distributors and retailers specifies that the distributor must only use the data for the purpose of providing distribution services to retailers and provides for obligations on distributors to securely manage the Consumption Data.

Information collected by flexibility traders

4.29 Changes to the Code were made in March 2020 via the Authority's Additional Consumer Choice of Electricity Services (ACCES)[64] project, which were intended to make it easier for a customer's agent (which can be a flexibility trader) to access Consumption Data.

4.30 Customers (or flexibility traders that have the permission of customers) can request Consumption Data free of charge up to four times in a 12-month period, after which retailers can charge a 'reasonable' fee. Retailers have five business days to comply with data requests.

Current arrangements to facilitate information sharing

4.31 The main existing arrangements regulated or provided by the Authority to facilitate information sharing are:

(a) the Data Template

(b) electricity Information Exchange Protocols (EIEP)

(c) the Electricity Market Information (EMI) website

(d) the Registry

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[62] DDA means a default distributor agreement based on the template set out in Schedule 12A.4 Appendix C. The DDA is a standardised use-of-system agreement between distributors and traders in respect of distribution services, provides default terms for traders to access distribution networks, and is designed to reduce the contracting costs of participants [Default Distributor Agreement Decision Paper (ea.govt.nz)]

[63] Permitted Purposes are defined in the Data Template and are to develop distribution prices, and/or planning and management of the network in order to provide distribution services to traders under the distributor's agreements.

[64] [ACCES project decision paper, Jan 2020]

(e) the My Meter page / Public registry API

The Data Template

4.32 The Data Template was introduced alongside the DDA Template in July 2020. The purpose of the Data Template is to provide distributors access to Consumption Data on default terms provided by the Authority unless parties agree to a contract for sharing this data under alternative terms.

4.33 The problem the Data Template was designed to address was the impasse between distributors and retailers on negotiating reasonable terms for distributors to access half-hourly Consumption Data held by retailers for purposes other than invoicing. The Electricity Price Review of 2019 also recommended changes were needed to ensure distributors have access to smart meter data on reasonable terms.[65]

4.34 The DDA decision paper outlined that providing distributors access to Consumption Data on reasonable terms would enable them to:

(a) develop more cost-reflective distribution pricing

(b) expand their networks more efficiently by analysing consumption patterns to improve investment plans

(c) plan maintenance more easily, and

(d) respond better to the uptake of DER.

4.35 The Data Template has several key requirements:

(a) the distributor must outline what purpose the data will be used for. Where the data has not been requested for a permitted purpose, the retailer can choose not to supply it

(b) the distributor must list the parties that have access to the Consumption Data under the agreement

(c) the distributor can only receive the Consumption Data once every six months, unless otherwise agreed

(d) the distributor must pay the retailer (or the retailer's MEP) reasonable costs incurred in supplying the data

(e) the retailer must supply half-hourly Consumption Data if this is collected by the MEP, otherwise it is non-half-hourly (ie, less frequent than every half hour) data, and

(f) the retailer must provide the data within ten working days of the distributor's request.

4.36 Issues that have been raised with the Data Template are covered in issue 1 of this chapter.

4.37 Note that the Data Template does not provide for requesting Power Quality Data.

The Electricity Information Exchange Protocol (EIEP)

4.38 EIEPs set out standard file formats for the exchange or provision of information. The EIEPs are designed to enable low cost, standardised and reliable information exchange between participants.

[65] Electricity Price Review: Final Report (mbie.govt.nz)

4.39 The EIEPs have been developed and revised over many years, supported, and coordinated by the Authority, and informed by industry consultation and a panel of industry representatives called the Standing Data Formats Group.[66]

4.40 Some EIEPs are regulated under the Code, setting out operational requirements participants must comply with.[67] EIEPs in their standardised format are designed for a defined purpose and cannot be used beyond what has been mandated (unless voluntarily agreed between the two parties).

The Electricity Market Information (EMI) website[68]

4.41 The EMI website publishes data, market performance metrics, and analytical tools to facilitate effective decision making within the New Zealand electricity industry. However, for privacy reasons, EMI does not publish ICP level Consumption Data, and the Consumption Data that is published is aggregated (generally to GXP[69] level).

The Registry[70]

4.42 The registry database facilitates the exchange of information between retailers, MEPs and distributors to manage reconciliation, invoicing and switching processes. The registry also manages the retailer switching process and contains static technical ICP information (not Consumption Data) to allow prospective new retailers to make an informed offering to a consumer. Various participants are required to enter information into the registry about an ICP:

(a) distributors create the ICP and enter information about the network connection of the ICP (such as the GXP, address, pricing, and loss categories)

(b) MEPs enter information about the metering located at the ICP (such as meter serial number(s), meter status, register content codes)

(c) retailers enter information about the reconciliation process at the ICP (such as the retailer's participant ID, reconciliation type, profile).

4.43 Part 11 of the Code details the management of information held by the registry and outlines the process for switching ICPs between retailers, MEPs, and distributors.

4.44 The registry also provides a secure File Transfer Protocol (FTP) service called the registry data hub. This enables participants to exchange data files, such as EIEPs, securely.

My Meter Page / The ICP Connection Data API

4.45 The My Meter Page[71] provides publicly available information based on ICP or residential address, such as generation capacity and generation fuel type. The ICP connection data API[72] enables similar information to be retrieved but for many ICPs at once. The connection data API restricts users to 50 calls per minute for 'search' and 75 calls per minute for 'get by ID' calls and/or 10 MB of data per hour.

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[66] Standing Data Formats Group (SDFG) — Electricity Authority (ea.govt.nz)
[67] Schedule 3 of the DDA outlines regulated EIEPs and includes EIEP1, 2, 3, 5A and 12.
[68] Electricity Authority - EMI (market statistics and tools) (ea.govt.nz)
[69] Grid Exit Point
[70] About the registry — Electricity Authority (ea.govt.nz)
[71] My meter — Electricity Authority (ea.govt.nz)
[72] Application Programming Interface EMI APIs (azure-api.net)

Box 1: Energy data and digitalisation in the UK

In conjunction with Innovate UK, Ofgem and the Department for Business, Energy and Industrial Strategy published a strategy and action plan in 2021 to digitalise the energy system for net zero carbon emissions by 2050.[73] Part of this plan was establishing the Energy Digitalisation Taskforce (the Taskforce), aimed at delivering a set of actionable recommendations to facilitate the digitalisation of the energy system.

The Taskforce published a report in January 2022 containing recommendations on how the energy sector can further enhance its digital activities, including unlocking value of customers assets and action through embedding a digitalisation culture.[74] There are six core recommendations, as listed below. Recommendations (1) & (2) are probably most relevant to this paper:

1) Unlock value of customer actions & assets

Government and the Regulator need to create policy, regulation, and digital infrastructure which enables industry to deliver the trust and assurance to unlock the value of customer actions and assets.

Actions include – develop a simple customer consent dashboard; mandate smart enabled energy assets; streamline asset registration; review customer protection regime; utilise smart meter data for public good

2) Deliver interoperability

The sector needs to deliver interoperability through the development and deployment of key Public Interest Digital Assets including a Digital Spine* solution.

Actions include – adopt network data standard; deliver energy asset register; deliver energy data catalogue; evolve flexible asset standards; deliver a digital spine for the system

3) Implement new digital governance approach & entities

4) Adopt digital security measures

Digital security principles and interventions need to be embedded throughout the sector to collectively enable safe digitalisation at scale.

5) Enable carbon monitoring & accounting

6) Embed a digitalisation culture

* The Digital Spine is described as "a thin layer of interaction and interoperability across all players which enables a minimal layer of operation-critical data to be ingested, standardised and shared in near real time".

The case for digitalising New Zealand's electricity system

4.46 It is clear that a lot of work has been done and thought has been given in the UK around the importance of digitalising their energy system for the benefit of consumers[75] and how best to achieve this. Even though New Zealand's authorising environment and

[73] Digitalising our energy system for net zero: strategy and action plan 2021 (publishing.service.gov.uk)

[74] https://esc-production-2021.s3.eu-west-2.amazonaws.com/2022/01/ESC-Energy-Digitalisation-Taskforce-Report-2021-web.pdf

[75] According to the Taskforce's 2021 strategy and action plan "the benefits of a digitalised energy system will be fundamental to help and encourage consumers to participate and prosper from the transition to net zero by enabling more tailored services, including for those who are low income or vulnerable. Data-driven insights will have the power to identify and advise consumers – with their consent – on appropriate solutions such as tariffs and services. A digitalised energy system could support consumers in their daily lives by making it easy to find a free spot to charge an electric vehicle, set the right room temperature to arrive home to, and remotely switch the dishwasher on in the middle of the day (when there is more solar energy on the system) to take advantage of lower energy prices. Everyone can benefit from the more accurate knowledge, insights and analysis that help deliver better quality and fairer products, services, and entrepreneurial opportunities."

energy ecosystem is not identical to the UK's the Authority is of the view that there is considerable common ground between the two. Therefore, in the interest of time and efficiency, we could use the Taskforce's findings, particularly the recommendations around unlocking the value of customer actions and assets and interoperability, to fast-forward work around digitalising New Zealand's energy system.

4.47 To be able to digitalise our energy system, participants need data that relates to how the system operates, the markets that send signals to system users, and the physical infrastructure located on the networks. This data is fundamental to enabling the development of the products and services that consumers require to gain maximum benefit from the electricity system. This is different to the data collected about consumer energy use, for example individual smart meter data. We discuss the issues and potential options to ensure the right parties have the right set of ICP-level consumption and power quality data available at the right time in the following sections of this chapter.

4.48 To transfer the UK findings and proposed approach into a New Zealand setting requires new standards, regulations, services, roles, and possibly new institutions. To that end the Authority is considering commissioning two separate studies to look into the merit and practicalities of implementing the recommendations of the UK's Energy Data Taskforce around unlocking the value of customer actions and assets and delivering interoperability in New Zealand.

4.49 The first study would look into:

- the issues that the Taskforce's customer related recommendations[76] could resolve
- whether they could be seamlessly and readily implemented in the current New Zealand regulatory and institutional settings and if not, what incremental or fundamental changes are necessary
- recommending next steps including identifying potential quick wins.

4.50 The other study would look into the definition, scope, potential delivery options and overarching governance requirements of a digital spine. The study could potentially focus on:

- clearly defining the problems that a 'digital spine' for the electricity system would solve
- comprehensive stakeholder identification
- assessing the technical feasibility and security requirements of a 'digital spine'
- providing evidence to inform future policy, regulation, and potential delivery options

4.51 Other actions proposed in the report to deliver interoperability, such as adopting a network data standard; delivering an energy asset register; delivering an energy data catalogue; and evolving a flexible asset standard are already being considered as part this chapter as well as chapter 7 (DER standards).

4.52 The Authority will continue monitoring developments in the UK and other jurisdictions for lessons and policies that could be adopted in New Zealand for the long-term benefit of consumers.

[76] Develop a simple customer consent dashboard; mandate smart enabled energy assets; streamline asset registration; reviewee customer protection regime; utilise smart meter data for public good

Q1. Do you see value in the Authority commissioning two separate reviews to look into the merit and practicalities of implementing the recommendations of the UK's Energy Data Taskforce around unlocking the value of customer actions and assets and setting up a "digital spine" in a New Zealand setting. The Authority will consult on the findings and recommendations of the reviews as appropriate.

What data and information do distributors and flexibility traders need, and why?

4.53 This section outlines the key pieces of data that distributors and flexibility traders say they need. The list of data is not intended to be exhaustive.

Distributors

Data need 1: historical non-aggregated[77] ICP-level Consumption Data and Power Quality[78] data:

4.54 This will enable distributors to undertake more efficient:

(a) network management

(b) power Quality management (including outage information), and

(c) network pricing.

4.55 The Authority has received feedback that detailed ICP-level data is not always necessary. However, we refer to ICP-level for simplicity and the fact is that smart meters do collect this data at each ICP. The data could be collected at a level more aggregated than ICP through installation of another device, but this would likely be inefficient as it would duplicate the capabilities of smart meters. Therefore, we assume for the purposes of the paper that the most efficient way of getting access to granular data for network management, Power Quality management, and network pricing is through existing smart meters (although data can also be obtained from DER such as solar panels and EV chargers).

4.56 **Priority[79]:** Simplified access to this data is a high priority – within the next 1-3 years.

Efficiency benefits in network management
Combining non-aggregated ICP-level Consumption Data (such as half-hourly ICP level Consumption Data) with a distributor's network capacity data provides distributors with a detailed picture of congestion on their LV networks, enabling them to identify specific areas that are driving capacity issues that will require upgrade

[77] Non-aggregated in this context means granular profile data such as, half-hourly Consumption Data or five-minute Consumption Data, as opposed to weekly or monthly Consumption Data.

[78] Power Quality Data refers to a range of data sets that can be used to support network management and planning. This can include *Volts, Watts, Phase Angle, Power Factor*. This can also include event data, such as: *power outage, power restoration, reverse power*. The Authority notes that this is also referred to as Network Operational Data (NOD).

[79] The data needs and issues in this workstream are prioritised based on what seems most important at this stage to achieve the desired outcomes, a judgement based on feedback the Authority has received. The Authority welcomes feedback on the prioritisation.

solutions (which can include NNS). This data will also allow distributors to confirm where additional connections (consumption or generation) can be added safely without requiring upgrades. For example, non-aggregated ICP-level data can be used to provide a detailed picture of congestion which can enable a distributor to pinpoint a subsection of the LV network that requires a capacity upgrade. Without this data, distributors would likely need to upgrade a larger section of the network which is more expensive (or possibly defer the upgrade because it is too expensive), resulting in either higher costs or Power Quality issues for the affected customers.
Efficiency benefits in Power Quality management
Non-aggregated ICP-level Power Quality Data (such as ICP-level voltage data) will help distributors identify Power Quality issues before they become serious. Historically, distributors have relied on customers to raise Power Quality issues (when they notice their lights flickering) but having access to this data would enable distributors to identify and address any issues before they become significant. This includes meter status data, such as last gasp, which is a signal that tells distributors when power is lost.
Efficiency benefits in network pricing
The 2019 Distribution Pricing Principles[80] and 2022 Practice Note[81] provided expectations for how distributors should set their prices. Having access to non-aggregated ICP data enables distributors to overlay prices on consumer load profiles to match network costs and assets. The Authority encourages distributors to consider pricing as part of their asset management and asset planning toolkits, and therefore distributors require data for those purposes (such as data on congestion). Distributors also require data that helps them create customer groups and tariffs in a manner that is consistent with the distribution pricing principles, for example that prices are subsidy free and residual charges are allocated in a least distorting manner. This also allows distributors to identify consumers who are positively or negatively affected, and by how much when developing price changes, especially when transitioning to more cost reflective pricing. It also allows distributors to calculate the impact on income levels by meshblock, matching proposed price increases to census information.

Data need 2: visibility of location, size, and functionality of (non-exporting) DER installed on LV networks[82]

4.57 This will enable distributors to have a better understanding of:

[80] Distribution pricing — Electricity Authority (ea.govt.nz)
[81] Distribution-Pricing-Practice-Note-2021-2nd-edition.pdf (ea.govt.nz)
[82] This will mostly be DER that sits ‘behind the customers meter’, on a consumer’s property.

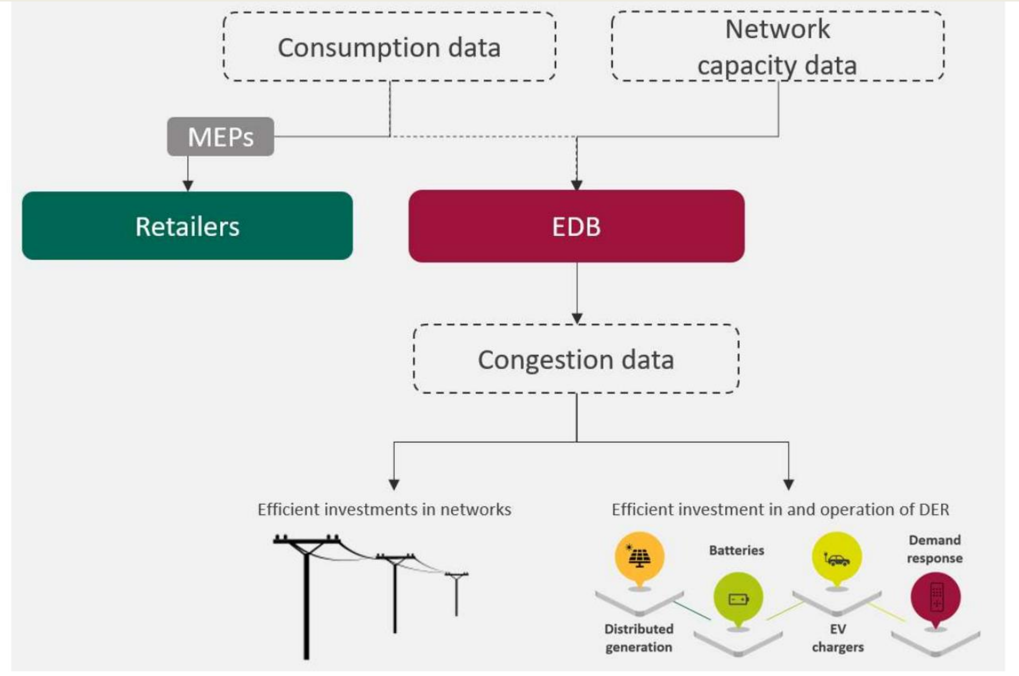
(a) the drivers of congestion on networks, to make optimal network investment

Box 2: How is congestion data generated and used?

Consumption Data is collected by MEPs who are contracted to provide it to retailers (although in some cases, distributors own the meters and collect the data themselves). Network capacity data is collected by distributors through their own network infrastructure. Distributors can negotiate access to Consumption Data from retailers or their MEPs (shown by the dotted lines). Network capacity data and Consumption Data help distributors understand congestion on their networks. The more granular the consumption and capacity data, the more useful it is.

Congestion data can be used by participants to make efficient investments to help manage congestion and expand capacity. For example, congestion data would be useful for a distributor investing in its network or a flexibility trader investing in the operation of DER to identify the most efficient solution to address capacity problems.

Figure 8: Generating and using congestion data



decisions. For example, if an LV network line is reaching capacity and EV penetration is low, this could signal to the distributor that they should look at options to increase capacity. Whereas if a line is reaching capacity and EV penetration is high, the distributor might not need to invest in a capacity upgrade, or a smaller upgrade could be more appropriate.

(b) what DER is 'controllable'; and therefore, what options could be available to manage the demand and supply of electricity and potentially avoid a costly network upgrade.

4.58 **Priority:** Access to this data is a medium priority – within the next 3–7 years. This prioritisation aligns with the FSR road map[83] (as DER operation is currently minimal,

[83] Consultations — Electricity Authority (ea.govt.nz)

visibility and observability of DER is high, therefore demand is easy to predict and forecast).

Data need 3: real-time non-aggregated Consumption Data and Power Quality Data

4.59 This will enable distributors to:

(a) understand real-time pressure on their LV network to assess when and where demand needs to be managed, and

(b) identify issues on the LV network in real-time, such as outages.

4.60 Definitions of 'real-time' vary. Ideally, this would be instantaneous access to data, but there will likely be intermediate steps before reaching this point, such as receiving data in half-hourly intervals, and then five-minute intervals.

4.61 **Priority:** based on the feedback we have received, access to real-time data is less of a priority given the low levels of DER uptake. However, as DER uptake increases, access to real-time data will become more important. No timeframe has been put forward due to the uncertainty around the data need.

Q2. Does this capture the key data needs for distributors to make informed business decisions that will unlock the potential of DER for the long-term benefit of consumers? If not, what data is missing and what would it be used for?

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

Flexibility traders

Data need 1: network congestion data on LV networks, and ICP-level consumption and Power Quality Data

4.62 Network congestion data on LV networks covers (1) a static picture of current congestion on LV networks, and (2) a projection of likely future congestion on LV networks. Ideally this would be at a granular (ICP) level, and would enable flexibility traders to:

(a) understand a customer's individual need (after being requested by the customer, rather than for unsolicited approaches) and tailor DER services to fulfil those needs

(b) identify network problems and offer solutions to distributors for these problems, and

(c) understand network capacity and therefore what DER offerings will or won't work.

4.63 ICP level consumption and Power Quality Data will enable flexibility traders to provide services to support network planning and management.

4.64 **Priority:** access to this data is a high priority – within the next 1–3 years.

Data need 2: visibility of the location, size and functionality of DER installed behind the customer's meter

4.65 This would enable flexibility traders to have a better understanding of:

(a) the drivers of network congestion. This enables flexibility traders to identify the areas of a network that will need upgrading before others and offer solutions accordingly

(b) controllable DER that can be accessed by a flexibility trader, and therefore what options could be available to manage the demand and supply of electricity and potentially avoid network upgrades. This information will also support flexibility traders' ability to develop services to provide to customers who own controllable DER (the repository of this information will be designed so it does not become a database for unsolicited approaches).

4.66 **Priority:** Access to this data is a medium priority – within the next 3–7 years. This prioritisation aligns with the FSR road map (because DER operation is currently minimal, visibility and observability of DER is high, therefore demand is easy to predict and forecast).

Data need 3: real-time granular network congestion data

4.67 This will enable flexibility traders to understand real-time pressure on LV networks. Flexibility traders will then be able to assess when demand and/or supply needs to be managed and offer services accordingly.

4.68 **Priority:** just as access to real-time data is less of a priority for distributors, this is less of a priority for flexibility traders. However, as DER become more common, access to real-time data will become more important. No timeframe has been put forward owing to the uncertainty around the data need.

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

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

How is the status quo expected to develop if no action is taken?

4.69 The data and information need of distributors and flexibility traders will become more important over time as electricity demand and DER uptake increase. If no action is taken, it is possible that distributors and flexibility traders would get access to more of the data and information they need by installing their own equipment. However, this could be a costly and inefficient solution if the data and information is already collected by existing smart meters (or smart appliances, for example smart hot water cylinders and smart heat pumps).

4.70 Over time, it is possible that distributors and flexibility traders will get access to the data they need from MEPs and retailers as they work through some barriers that are currently preventing this from occurring. However, this might not happen soon enough given there is no commercial incentive for retailers to share this information (as retailers can only recoup 'reasonable costs' for the data). In fact, there is a disincentive if a retailer considers that the data might be used to compete with it for certain services.

4.71 If no action is taken, it is unlikely that the visibility of DER (especially size, location, and functionality) installed behind the meter would improve given the challenges and costs associated with collecting this data.

4.72 If no action is taken, the Authority considers it possible, but unlikely, that flexibility traders will get access to the granular congestion, and granular consumption and Power Quality

Data that they need. It would require distributors gaining access to granular historical consumption and Power Quality Data and then sharing that information with flexibility traders. There should be an incentive for distributors to share this information as it could lead to solutions being proposed to their problems, but on the other hand there could be a disincentive if the distributor considers a flexibility trader might use that congestion data to provide services in direct competition with a distributor-owned business.

The Consumer Data Right

4.73 On 5 July 2021, the Government agreed to establish a consumer data right (CDR) to give consumers greater choice and control over their data. The CDR will require businesses that hold data (data holders) to share prescribed data that they hold about consumers (CDR data) with trusted third parties (data recipients), at the consumer's request or with their consent.

4.74 The CDR will be rolled out on a sector-by-sector basis via designations made by the responsible Minister. MBIE is preparing for further stakeholder engagement and an exposure draft Bill. Following this, the introduction of a CDR Bill to Parliament is expected sometime in 2023. Further work will need to be done on regulations and designations from 2023 onwards, as well as on implementation work, before the CDR can be applied to individual sectors.

4.75 It is likely that the CDR will not be rolled out to the Energy Sector before 2026. However, when it is rolled out it will have an impact on how data is shared as it will effectively transfer ownership of a consumer's data (including, but not limited to, personal information to the consumer). The impacts are yet to be determined as they will depend on the details of the legislation and the sector-specific design that must be finalised.

Problem definition

4.76 This section is split into three parts:

a) **Part 1:** the issues hindering access and availability of key data for distributors.

b) **Part 2:** the issues hindering access and availability of key data for flexibility traders.

c) **Part 3:** the steps that would improve data access and availability and enhance disclosure to consumers to assist with data access.

4.77 Some possible options are presented that the Authority is seeking feedback on now. The Authority is proposing to progress two of these options as soon as practicable (*amendments to the data template* and *provide model privacy disclosure terms for retailers*), while the other options will take more time to develop, and some options are mutually exclusive. The Authority has explained where this is the case.

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

Issue 1: Improvements to the default Data Template are required to enhance its workability

4.78 The Data Template was introduced alongside the DDA Template with the objective of allowing a distributor access to Consumption Data on reasonable terms for the purpose of managing its network, while also providing retailers with assurances regarding how the distributor will use and store the data.

4.79 The Authority has been made aware of issues with the Data Template that if addressed would improve its workability. The main issue that has been raised is that the Data Template prevents distributors from merging Consumption Data with other data sets, unless prior written agreement is given by the retailer. Distributors have raised that the Consumption Data holds no value in fulfilling any of its permitted purposes unless they can combine it with other datasets.[84]

4.80 In 2021, the Electricity Networks Association (ENA) and Electricity Retailers Association of New Zealand (ERANZ) worked with interested industry participants to agree on some minor improvements to the Data Template to address these issues with it.

4.81 The Authority has received feedback from distributors and retailers that:

(a) they prefer to use the ENA / ERANZ data template variation as it enables them to merge Consumption Data with other data sets.

(b) there is confusion among distributors and retailers around whether to use the Data Template or the ENA / ERANZ variation.

4.82 Retailers have also raised that every time the variation is used, they must undertake a legal review and check that further amendments have not been added.

Amendments to the Data Template

4.83 While staff are aware of several Data Template agreements that are in place, staff have been told by several distributors that they haven't engaged with retailers to negotiate a Data Template agreement yet. Therefore, the Authority considers that codifying the ENA / ERANZ variation would improve the workability of the future agreements.

4.84 The Authority has also received feedback that:

(a) changing the maximum frequency for receiving data from six-monthly to monthly would be of greater value to distributors at no (or negligible) extra cost to retailers or MEPs. The Authority accordingly proposes amending the Data Template to change the maximum frequency for receiving data to monthly.

(b) MEPs should be directed by their retailer to provide the Consumption Data to distributors by default. Distributors have provided feedback that it is preferable to obtain Consumption Data from MEPs as they will use a uniform file format for all the retailers within the relevant distribution network. Retailers have also provided feedback that they do not want to be the middle person for the provision of data. This change will go towards helping to address this. The Authority accordingly proposes amending the Data Template to make MEPs the default providers of Consumption Data.

(c) it could be clearer that 'reasonable costs' in Clause 6 of the Data Template, which provides that '*The distributor must pay the Trader's or the Trader's Metering Equipment Provider's reasonable costs incurred in supplying any information requested under clause 2'*, extends to the provision of Consumption Data by MEPs. The Authority wants to clarify that this applies to both retailers and MEPs, in other words MEPs can only recover reasonable costs for the provision of the

[84] Some examples of use cases that distributors have identified where they would like to be able to combine Consumption Data are:

(a) Weather data – to understand how the network is affected by weather

(b) Census data and Auckland University deprivation index– to understand consumption patterns of different groups of consumers/households

(c) Property valuation and council data – in order to understand how property size and age characteristics affect peak demand

Consumption Data. The Authority notes at this stage it does not cover Power Quality Data and expanding a 'reasonable costs' requirement to Power Quality Data might be required in the future.

4.85 Staff consider that the amendments are relatively minor but will have a more than minor positive impact on the flow of Consumption Data from retailers or MEPs to distributors. Subject to feedback, Staff will look to consult on the Code change alongside forthcoming consultation on proposed changes to the DDA.

Q6. Do you agree that the Authority should amend the Data Template to address the above issues to improve its workability? If not, why not?

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

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

4.86 For distributors to receive ICP-level data for their distribution network, they may need permission from retailers, for the following reasons:

(a) MEPs are collecting the ICP data for and on behalf of the retailer via their metering agreements and retailers will have various rights in relation to the ICP data collected by MEPs through smart meters. Therefore, MEPs may need to obtain permission and retailers can seek assurances that this data will be used for permitted purposes (such as network planning and management, or to develop distribution pricing), and not for any contestable services that distributors might compete with retailers for

(b) ICP Data may be personal information as that term is defined in the Privacy Act. As the retailer is the regulated 'agency' for the purposes of the Privacy Act in relation to the personal information that the retailer has contracted the MEP to collect and provide to it, then the retailer will need to understand what the data is being used for and ensure that they have complied with Information Privacy Principle (IPP) 3[85] by making their customer aware of how their personal information will be used, including on what basis it will be disclosed to third parties (such as distributors).

4.87 Distributors say that having to obtain permission from many retailers to receive ICP level data[86] directly from MEPs can mean high transaction costs, generated by:

(a) having to seek permission from every retailer on their network, which could be a very large number of retailers

(b) the time it takes to get permission as retailers are not incentivised to provide ICP level data to distributors. In fact, there can be a disincentive due to perceived risks of the data being used for competitive purposes or potential privacy concerns; and

[85] Privacy Act 1993 No 28 (as at 01 December 2020), Public Act 6 Information privacy principles – New Zealand Legislation

[86] ICP-level data is specific to an individual ICP. Each household generally has its own ICP, so this data is often referred to as ICP-level data and 'household level data'. ICP-level data includes Consumption Data and some Power Quality Data.

(c) having to get retailer permission for Consumption Data *and* Power Quality Data separately, as the Data Template is the main vehicle for accessing Consumption Data, but it does not cover Power Quality Data.

4.88 While the Authority has heard that there are now several instances of where distributors are successfully receiving data directly from MEPs after having obtained permission from retailers, the Authority considers the transaction costs associated with obtaining retailer permission are unnecessarily large and this is an issue worth addressing to make it easier for other distributors (and flexibility traders) to get data directly from MEPs.

Possible option to address: Code amendment to clarify MEPs must provide ICP data directly to distributors and flexibility traders

4.89 The Authority is considering prioritising amending the Code to clarify that MEPs must contract directly with and provide both Consumption Data and Power Quality Data to distributors and flexibility traders for a set of permitted purposes i.e., without the need for retailer permission. This would provide distributors (and flexibility traders) a mandate to access this data directly from MEPs with minimal administrative burden and would remove the need to obtain retailer permission. Further consideration would need to be given to existing contracts, the commercial arrangements, and what privacy protections are needed, but the Authority is confident these can be put in place. 7.15.4 of the National Electricity Rules in Australia is an example of a similar arrangement.

4.90 This option would also help address Issues 3 (improving distributor access to Power Quality Data) and 8 (improving flexibility trader access to ICP data), and likely render the Data Template redundant.

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

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

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

4.91 For distributors to receive ICP level Power Quality Data directly from MEPs, there are different considerations, such as privacy and commercial. As is the case with Consumption Data, whether retailer permission is needed will depend on the contractual terms between the retailer and MEP. However, unlike Consumption Data there is no Default Template in the Code for the retailer to provide Power Quality Data to distributors, so distributors must negotiate contracts from nothing to obtain this data.

Possible option to address: Modify Data Template to include Power Quality Data

4.92 There is also no default template, as there is for Consumption Data, which would help streamline the process for a distributor to obtain retailer permission from a retailer to collect this data. The Authority is considering whether the Data Template could be expanded to include Power Quality Data, which would help with obtaining retailer permission.

4.93 Consideration would also be given to whether Power Quality Data is personal information and if it is what disclosures are being made to the consumer about how their personal information is being used.

4.94 The option described under Issue 2 of amending the Code to clarify that MEPs can contract directly with and provide both Consumption Data and Power Quality Data to distributors for a set of permitted purposes (without the need for retailer permission) would also help address this issue. This might remove the need to modify the Data Template to include Power Quality Data.

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

Issue 4: In addition to gaining retailer permission to collect ICP data direct from the MEP (eg, by completing a Data Template), a distributor must also negotiate an access agreement with the MEP

4.95 Some participants have said a default template could be used to streamline negotiations with MEPs for data. A default template could cover privacy obligations, data format, delivery frequency, and payment terms. At this stage, the Authority has not developed a view on whether a default template is an option that should be pursued. It is possible that requiring MEPs to publish standard 'pay-as-you-go' terms that are open to all parties would help streamline negotiations and do away with the need for a default template (see Issue 5).

4.96 It is likely the costs of developing a template would be high and there are already several examples of MEPs providing ICP data directly to distributors, which suggests these challenges are navigable. However, the Authority is open to considering the option of a template to reduce the challenges associated with distributors (or flexibility traders) accessing data directly from MEPs.

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

Issue 5: MEP pricing for provision of ICP data and other services to distributors (and other parties) is not transparent[87]

4.97 Concerns have been raised that MEPs can use, and are using, their effective monopoly position in the provision of ICP data to distributors to charge unreasonable prices. The Authority sought additional evidence on this possible issue in its request for additional information.

4.98 Based on the information received, the Authority does not consider unreasonable pricing is an issue at this stage. It appears it is still relatively early when it comes to the provision of ICP data and the related data services from MEPs directly to distributors. This means that the type of data, format, and frequency requested often differs. The Authority expects that over time, as the market for the provision of data to distributors matures, data services will become more standardised resulting in more consistent and transparent pricing. However, given the importance of access to smart meter data, the Authority is concerned that this might not happen quickly enough.

[87] Distributors also raised concerns there are large costs associated with the IT tools and resources to collect, store, and analyse the data they receive. Also, distributors commented the default price-quality path does not provide enough operating expenditure to purchase the data required. This feedback has been passed on to the Commission.

Possible option to address: Require MEPs to publish standard 'pay-as-you-go' terms that are open to all parties

4.99 To support the standardisation, transparency of pricing, and equal access to data the Authority is seeking feedback on whether it should consider further implementing IPAG's Input Services[88] recommendation that MEPs be required to publish standard 'pay-as-you-go' terms open to all parties, which would include service schedules, terms and conditions, and pricing that allows costs for any given ICP to be determined.

4.100 This is one of the recommendations in response to the IPAG's findings that the MEP services market has significant monopoly elements that cannot be overcome by commercial pressures alone and that some existing contracts may inhibit competition by restricting access to services (see Issues 18 and 19 on slide 37 of the PowerPoint Presentation (ea.govt.nz)).

4.101 The Authority notes that more detail on how this option would work in practice is needed before it can be comprehensively assessed, however, the Authority is interested in initial feedback on whether requiring MEPs to publish default data access arrangements would help improve access to data and what these arrangements could look like.

4.102 This option could also help address Issues 4 (reducing the barriers to distributors collecting data directly from MEPs) and 8 (improving flexibility trader access to ICP data).

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

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

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

Issue 6: Distributors need better visibility of (non-exporting) DER

4.103 Distributors have information on the location and size of some DER on their network. This is because distributors are required to record in the registry the nameplate capacity and the fuel type of distributed generation that it is capable of exporting.

4.104 But distributors do not necessarily have visibility of the location, size and functionality of other types of DER that reside on their LV networks, such as electric vehicles (V2G exporting), static (stationary) batteries (including chargers where fitted to the battery), and EV chargers. It is possible for distributors to analyse Consumption Data to infer whether a household has an EV, but there are shortcomings to this workaround. For example, it is not the best way to identify the size, location, and type of DER, and it does not provide information on whether the DER is controllable or not.

4.105 The FSR project and related industry projects, such as Wellington Electricity's EV Connect Roadmap, acknowledge the importance of increasing the visibility of DER to better forecast and predict network pressures.

4.106 The Authority considers that if the visibility of the location, size and functionality of DER is improved it would help distributors in planning and preparing for the additional demand

[88] IPAG's 2021 Input Services access advice: PowerPoint Presentation (ea.govt.nz)

from DER. However, due to the low levels of DER penetration in New Zealand, the Authority considers that this is a medium priority issue and that improving the visibility of large DER should occur within the next 3–7 years (consistent with the prioritisation in the FSR roadmap).

4.107 The Authority is however considering an improvement to the registry fields as an incremental improvement in the meantime (see paragraph 3.110 below). [89]

> **Q15. Do you agree that distributors' visibility of the location, size and functionality of DER should be improved within the next 3–7 years to support network planning? If not, why not?**
>
> **Q16. Do you have any views on the type and size of DER that need more visibility?**

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

4.108 While distributors commented that having real-time[90] consumption and Power Quality Data will be important in the future as DER becomes ubiquitous, improving access to historical consumption and Power Quality Data has been the priority. Some distributors have commented that real-time Consumption Data and Power Quality Data won't be needed for at least five years.

4.109 From submissions and discussions with distributors, the key issue preventing distributor access to 'real-time' Consumption Data and Power Quality Data is that MEPs are only just beginning to offer this data service. It is also possible that in future, smart appliances will be able to provide real-time Consumption Data and Power Quality Data.

> **Q17. The Authority acknowledges that definitions of 'real-time' vary, please explain what real-time data means to you.**
>
> **Q18. Do you agree that access to 'real-time' consumption and Power Quality Data won't be needed for at least five years?**

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

Issue 8: Flexibility traders do not have equal access to ICP data

4.110 Flexibility trader access to ICP data must be improved to ensure they have the same level of access as distributors (and retailers), who they might compete with to provide

[89] We are also considering whether the threshold to install a generation meter should be modified (eg reduced from the current 10MW to a lower threshold, such as 0.1MW) and whether the requirement to provide information to the reconciliation manager should be modified. We are also considering whether the metering and information provision requirement should apply irrespective of whether a DER injects energy into the network or whether the energy is consumed behind the ICP meter. Earlier this year the Authority signalled its intention to consider such issues with availability of behind-the-meter data in the context of proposed Code amendments to support the implementation of the new TPM (Long-form report (ea.govt.nz) paragraphs 2.26 to 2.31). The Authority will consult further with stakeholders before making any specific changes in this area.

[90] The Authority acknowledges that the definitions of 'real-time' vary. Ideally, this would be instantaneous access to data, but there will be intermediate steps before reaching this point, such as receiving half-hourly Consumption Data within hours of collection, and then 5–10-minute intervals.

contestable services. For example, there is no Data Template for flexibility traders to facilitate bulk access to ICP Consumption Data.

Possible options to address: Modify Data Template and Code change

4.111 To address this, the Authority is considering:

(a) modifying the Data Template, so that flexibility traders can use it to obtain the same access to Consumption Data as is afforded to distributors (and Power Quality Data if the Data Template is expanded in this way), or

(b) amending the Code to clarify that MEPs must provide ICP data directly to flexibility traders (and distributors) for a set of permitted purposes without the need for retailer permission. This would do away with the need for a flexibility trader Data Template as retailer permission would not be needed.

4.112 These measures could be implemented alongside the IPAG's Input Services recommendation that MEPs publish standard 'pay-as-you-go' terms open to all parties to support the standardisation and transparency of pricing, and equal access to data.

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

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

Issue 9: Flexibility traders do not have access to granular network congestion data on LV networks

4.113 The main issue preventing flexibility traders from getting access to (1) a static picture of current congestion on LV networks, and (2) a projection of likely future congestion on LV networks, is that distributors do not have access to granular historical Consumption Data to calculate congestion on their LV networks.

4.114 However, once distributors can calculate network congestion, there are currently no requirements in place for this information to be shared with flexibility traders.[91] It is possible that distributors will be disincentivised to share congestion data if they feel it will be used by flexibility traders to offer services that compete with a distributor's related businesses. However, it should be beneficial to distributors to share this data as flexibility traders could offer solutions to network problems caused by congestion.

4.115 The Authority considers this is an issue that must be addressed within the next 1–3 years to support the development of a competitive and efficient flexibility services market. The Authority will continue working to improve distributor access to historical Consumption Data, and visibility of DER, for distributors to calculate granular congestion data.

[91] There are existing Information Disclosure requirements (clause 2.3.13) specific to related party transactions which require affected distributors to provide a map of their anticipated network expenditure and network constraints. However, not all distributors undertake related party transactions, meaning these requirements do not apply to all distributors. Also, Part 6 of the Code requires distributors to publicly disclose '*a list of all locations on its distribution network that the distributor knows to be subject to export congestion; and a list of all locations on its distribution network that the distributor expects to become subject to export congestion within the next 12 months*'.

4.116 The Authority notes the Commerce Commission, in its targeted Information Disclosure (ID) review for distributors, is considering options that will help stakeholders understand the current and likely future constraints on distribution networks.[92] These options range from simply requiring distributors to report on their plans and progress and different scenarios in this area, to more prescriptive approaches that could require distributors to provide information on current and expected constraints in a standardised (geo-spatial) format. The Authority will continue working with the Commerce Commission on what this requirement could look like.

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

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

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

4.117 The main source of DER information for flexibility traders is the information on distributed generation (DG) in the registry. Flexibility traders can access this information via the ICP Connection Data API on EMI or can submit one-off queries on the Authority's My Meter page (as discussed earlier in this chapter).[93]

4.118 Some shortcomings with the registry fields and/or Part 11 requirements[94] have been identified:

(a) there is only one field available in the registry for the distributor to enter a DG fuel type. This means that the complete fuel mix at an ICP is not visible to users of the registry in situations where there is more than one generation type behind the meter, (e.g., a combination of solar and battery). This also means that the capacity shown is the aggregated capacity of all forms of generation at the given ICP

(b) the requirements are only applicable to DG that can export into the network. This means there is incomplete visibility in the registry of where other DER resides, such as EV chargers

(c) batteries are not an available option for selection as a fuel type in the registry and can only be selected as 'other' fuel type.

4.119 A registry user can see the DG capacity and fuel type (albeit with the limitations outlined above). However, the functionality of the registry is such that this is only visible per ICP, after the user has searched for the relevant ICP or location. In other words, you need to know where to look.

4.120 The Authority considers that if the visibility of the location, size and functionality of DER is improved this will help flexibility traders understand the drivers of network congestion, what DER are 'controllable', and what services could be offered to owners of DER. However, relative to the other issues in this paper, the Authority considers that this is a lower priority issue due to the low levels of DER penetration in New Zealand whereas

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92 See page 83 and Tranche 2 issues for consideration in Attachment A: Targeted-information-disclosure-review-for-electricity-distribution-businesses-Tranche-1-draft-decisions-paper-3-August-2022.pdf (comcom.govt.nz)

93 EMI APIs (azure-api.net) My meter — Electricity Authority (ea.govt.nz)

94 The requirements for distributors on recording distributed generation information in the registry are set out in Part 11 (Registry information management) of the Code. Code clause 7(1)(o) places requirements on distributors to provide the nameplate capacity and the fuel type of the distributed generation connected to their network

improving the visibility of large DER should occur within the next 3–7 years (consistent with the prioritisation in the FSR roadmap). [95]

Possible option to address: Modify the DER fields in the registry

4.121 Rather than creating a separate DER registry, the Authority considers that amending the registry data fields could help improve the visibility of DER. For example, the DER fuel type drop-down list could be expanded to include batteries and other forms of DER, and different combinations of DER.

4.122 Depending on its design, this option could also help address Issue 6.

Q23. Do you agree that visibility of the location, size and functionality of larger DER needs to be improved within the next 3–7 years to help understand the drivers of network congestion, what DER is 'controllable', and what services could be offered to owners of DER? If not, why not?

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

Q25. Do you think that the Authority, instead of a DER registry, should consider amending the registry data fields and /or requirements to improve DER visibility?

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

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

4.123 The main barrier preventing flexibility traders from getting access to real-time congestion and ICP data is that MEPs are only just beginning to offer this data service. However, this has the same priority as Issue 7, which is low. Therefore, the Authority proposes prioritising work on addressing the other issues outlined in this paper.

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

Part 3: Enhancing disclosure to consumers to enable data access.

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

4.124 The Authority would like to facilitate improved transparency practices within the electricity industry, which should in turn assist with better flows of data.

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[95] However, as noted above (footnote 84) we are also considering whether to propose amendments relating to the threshold to install a generation meter and requirements to provide information on generation to the reconciliation manager. These initiatives could progress on an earlier timeframe (eg, the next 1-2 years).

4.125 At present:

(a) ICP-level data[96] can be personal information[97]

(b) retailers indirectly and MEPs directly collect ICP-level data through smart meters

(c) retailers and MEPs may disclose ICP-level data to third parties including distributors and the Authority. Where ICP-level data is personal information then the entity that controls the collection is the 'agency' for the purposes of IPP 3. When MEPs collect personal information pursuant to a services agreement with retailers, the retailer is responsible for complying with IPP 3.

(d) IPP 3 provides that if an agency collects personal information from the individual concerned, the agency must take any steps that are, in the circumstances, reasonable to ensure that the individual concerned is aware of (amongst other things) the fact that the information is being collected, the purpose for which the information is being collected, and the intended recipients of the information. The primary responsibility is on retailers to be transparent about how it is using and disclosing the information that it collects.

(e) improved transparency would also ensure better industry compliance with IPPs 5, 6 and 7, which are aimed at ensuring individuals can obtain access to, and correct, their personal information, and IPP9 that requires that personal information be deleted after it has been used for the purpose it was collected

4.126 Retailers, for the most part, maintain the direct contractual relationship with the individual to whom the personal information relates.

4.127 This focus on improved transparency is consistent with the Ministry of Justice current consultation *Broadening the Privacy Act's notification rules*[98] that suggests imposing transparency obligations on those third parties using personal information but who were not responsible for its original collection but who collected the personal information indirectly through a third party.

The Authority will provide model personal information disclosure terms

4.128 On this basis the Authority is proposing publishing some model personal information disclosure terms for retailers to include in their terms and conditions or privacy notices. These terms would ensure consumers know:

(a) what ICP-level data is being collected

(b) what ICP-level data is being disclosed to distributors and other third parties, including the Authority, and for what purpose

(c) include links to the distributor's and third party's privacy notices.

4.129 At this point the Authority does not propose making these terms mandatory, although it would consider carrying out a review after publishing the final model terms to assess industry alignment.

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[96] ICP-level data is specific to each individual ICP. Each household generally has its own ICP, so this data is often referred to as ICP-level data and 'household level data'. ICP-level data includes Consumption Data and some Power Quality Data.

[97] Personal Information is information that is 'about an identifiable individual'. It must be about a natural person, not a company, and be connected to a named or reasonably identifiable, individual. An individual is reasonably identifiable if it is possible to work out who they are using any reasonably accessible resources. Some information may not be personal information when considered on its own but may become personal information when linked with other information.

[98] https://www.justice.govt.nz/justice-sector-policy/key-initiatives/broadening-the-privacy-acts-notification-rules/

4.130 Alongside the model privacy terms, the Authority could also consider working with industry to improve privacy preserving and minimisation techniques if that was considered helpful.

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

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

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

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

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

5 Market settings for equal access

Introduction and scope

5.1 This chapter considers whether any changes are needed to the distribution market settings. There are some potential issues to consider:

(a) some distributors seem at this stage to prefer network investments over the equivalent non-network solutions (NNS);[99]

(b) some distributors, having decided to choose NNS over network investments, nevertheless prefer to self-supply NNS, rather than relying on competitive procurement; and

(c) distributors might use their unique position in distribution to secure an advantage in NNS and / or downstream, contestable markets.

5.2 We identify some tentative interventions to adjust the existing market settings and present them as options for feedback in this paper.

5.3 The potential (and desired) impact of the tentatively preferred options is that the emerging market for flexibility services will develop faster if distributors choose NNS where they are the efficient option, and then use competitive procurement to obtain these services.

5.4 As noted in the Authority's *2021 Discussion Paper,*[100] the net benefits of intervening to optimise the potential value of DER were estimated by consultants Sapere at $6.9 b for the period 2021–50. These benefits depend on getting the market settings right so that distributors, consumers, and third parties are all incentivised to invest sufficiently in DER and NNS. Market settings should also ensure an efficient mix of self-supply, competitive procurement, and competitive provision of NNS.

5.5 The emerging market for flexibility services should be nurtured to ensure controllable DER are used in a way that secures the maximum possible benefit from them. Flexibility service traders are expected to aggregate and exploit controllable DER to meet the demands of all energy market participants, including consumers themselves.

5.6 A key benefit of flexibility services is that they can make controllable DER available to relieve network congestion and thereby avoid, reduce, or delay the need for distributors to invest in upgrading, augmenting, or replacing parts of their networks.

5.7 As DER uptake increases, there should be more opportunities for DER trading and exploitation by means of flexibility services, to manage congestion and reduce network investment. Flexibility services can also supply other parts of the value stack, such as transmission alternatives, wholesale alternatives, and ancillary services. This means there are several other potential buyers of flexibility services: the grid owner, the system operator, and retailers.

5.8 In this Issues paper, we recognise that the availability of and market for flexibility services is fledgling, and distributors have a key role to play. However, the Authority needs more information on the utilisation and procurement of NNS by distributors, to evaluate whether they are making efficient choices and supporting the development of a competitive market. We note the transfer of the Corporate Separation and Arm's-Length Rules into the Code (the new Part 6A) and Parliament's intention for the Authority to be able to apply these rules to a wider range of electricity sector activities. If it seems

[99] Non-network solutions (NNS) are the same as flexibility services although in this report we tend to use NNS to mean projects that comprise flexibility services (derived from controllable DER) bundled together to deliver functionality as an alternative choice, which would be a network investment (also a solution or project). See the Appendix for some suggested definitions of relevant terms.

[100] See https://www.ea.govt.nz/assets/dms-assets/28/Updating-the-regulatory-settings-for-distribution-networks.pdf

distributors are clearly preferring self-supply of flexibility services when market options exist, these rules could be developed to promote competition in evolving contestable markets.

5.9 Several distributors stated in their responses to the information request that they would see themselves as conflicted if they were to operate flexibility service trading platforms. As mentioned earlier, this corresponds to the views of the Council of European Energy Regulators (CEER)[101] and IPAG,[102] although in the UK, Ofgem[103] continues to prefer 'optionality' in this matter, recommending instead 'least regrets' measures such as enhancing access to data for all interested parties in the meantime.

Desired Outcomes

5.10 Ideally, market settings should:

(a) ensure both network investments and NNS are considered for increasing the capacity of a distribution network, so the most efficient option is pursued

(b) ensure the benefits of market competition are realised by encouraging distributors to procure NNS by competitive tender

(c) promote a level playing field for competitors in the market for NNS, so that flexibility services can be offered to all buyers in the value stack.

Status quo

5.11 Distributors plan network upgrades based on capacity, and existing and forecast demand, and publish this information in their asset management plans (AMP). The Commerce Commission requires 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, an overview of any network investments and NNS considered, and the basis for selecting the preferred solution. This includes considering whether NNS are more efficient than traditional network solutions.

5.12 Distributors are required under Part 4 of the Commerce Act to consider whether NNS are a viable alternative to network solutions and present this in their AMP. The quality of the assessment of non-network alternatives has not yet been reviewed by the Commission, but might be in future, and this topic was touched on in its latest review of AMPs.[104]

5.13 The Commerce Commission is currently reviewing its Information Disclosure (ID) regulations and its Input Methodologies. 'Tranche 2' of the Commission's targeted review of Information Disclosure requirements for electricity distributors[105] includes the following two considerations:

(a) proposed changes to expand ID requirements for distributors to include information on distributor investigations undertaken and investment into flexibility resources; and

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[101] Council for European Energy Regulators, 22 March 2019. *New services and DSO involvement: a CEER conclusions paper.* Distribution systems working group. Ref. C18 DS46-08.

[102] IPAG, IPAG Equal Access Advice 2021

[103] Ofgem, 2019. https://www.ofgem.gov.uk/publications/ofgem-position-paper-distribution-system-operation-our-approach-and-regulatory-priorities

[104] https://comcom.govt.nz/__data/assets/pdf_file/0032/270896/Decarbonisation-AMP-Review-18-November-2021.pdf

[105] See https://comcom.govt.nz/regulated-industries/electricity-lines/projects/targeted-information-disclosure-review-for-electricity-distribution-businesses

(b) proposed changes to align AMP content requirements with work on the Electricity Networks Association's Network Transformation Roadmap.[106]

5.14 As these AMPs are published on distributor websites, third-party suppliers of flexibility services could read the AMPs to look for opportunities to provide distributors with NNS. Some distributors submitted that they have signalled their need for capacity upgrades / NNS in their AMPs but received no offers, although that could be because third parties did not pick up those signals, as the AMPs can be lengthy and the need for NNS not always readily apparent in them.

5.15 Some distributors have gone ahead and supplied flexibility services themselves or awarded the work directly to a preferred provider without running a tender, which can make it difficult for flexibility service providers to get a foothold in the emerging market for NNS. A few distributors have used a competitive process.

5.16 The Commerce Commission enforces some rules that apply to the procurement of NNS by the distributors when they choose to self-supply:

(a) the cost allocation rules[107] stipulate that only costs attributable to the regulated service of distribution can be allocated to the regulated service – for example, ripple control. If a regulated supplier uses some of its assets (or incurs operating costs) to deliver the regulated service as well as supplying services that aren't the regulated service, then they will need to apply the cost allocation rules to attribute the resulting costs between the regulated and non-regulated services. So, in the case of ripple control, some distributors might have a portion of the ripple control plant value allocated to non-regulated services, which therefore (if they are non-exempt) won't go into the revenue caps; and

(b) the related party transaction rules[108] are intended to ensure that costs paid by distributors to their related businesses in respect of assets or services are stated at prices that would apply in arm's-length transactions.

5.17 The Commerce Commission also enforces Part 2 of the Commerce Act, which prohibits (amongst other things) anti-competitive arrangements and the misuse of market power.[109] Part 2 may apply to distributors' decisions to allow or not allow third parties to provide services on their networks where those decisions have an anticompetitive purpose, effect or likely effect.

5.18 The current state of the flexibility services market is as follows:

(a) The emerging markets for NNS are open to distributors themselves, as well as third-party participants. In practice, however, there are problems with access to data (for both distributors and third parties)[110] and distributors have not presented many opportunities to third parties for them to provide flexibility. At present, most distributors seem to be inclined to self-supply NNS, as and when needed. This

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[106] See https://www.ena.org.nz/home/document/484#:~:text=The%20Network%20Transformation%20Roadmap%20has,be%20used%20in%20the%20future.

[107] See https://comcom.govt.nz/__data/assets/pdf_file/0017/60542/Electricity-distribution-services-input-methodologies-determination-2012-consolidated-20-May-2020-20-May-2020.pdf

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

[109] The prohibition on misuse of market power in s 36 of the Commerce Act 1986 has recently been significantly amended by the Commerce Amendment Act 2022. The new prohibition comes into force in April 2023 and will prevent entities with a substantial degree of market power from engaging in conduct with the purpose, effect, or likely effect of substantially lessening competition in a market.

[110] Discussed more fully in Chapter 3.

may reflect either a perception or reality that there are few third-party suppliers of NNS, but this is a circular problem.

(b) Nevertheless, it appears the market for flexibility is at least partly contestable, because several third parties have sold services to distributors, successfully competing with the self-supply options of distributors.

(c) At least one distributor is investing in some additional capabilities, to become a smart distributor, taking the next step of using more frequent data feedback from meters to control the use of DER. This would not (yet) extend to operating a trading platform, as the distributors concerned would be the exclusive buyers of any flexibility services procured.

How is the status quo expected to develop if no action is taken?

5.19 The uptake of DER and the market for flexibility services are expected to increase, but at a slower than optimal rate, because:

(a) distributors tend to prefer investment in network solutions

(b) some distributors prefer to self-supply NNS whereas competitive procurement might stimulate the market more

(c) some projects are not financially viable unless they can access all value streams and distributors are not necessarily motivated to facilitate that, which disincentivises the uptake of DER.

5.20 A minority of distributors, such as Aurora and Powerco, have pursued NNS supplied by third parties, and are likely to continue to do so, through competitive processes. Some others may follow suit.

Problem definition

5.21 Potential problems that may warrant a change to the market settings were identified in the *2021 Discussion Paper*, and following submissions have been re-cast as follows:

Issue 1:
Distributors may prefer network solutions when NNS could be more efficient

Issue 2:
Distributors may prefer to self-supply NNS rather than use competitive procurement

Issue 3:
Distributors may use their monopoly position in distribution to secure an advantage in contestable markets

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

Why is this an issue?

5.22 Opportunities may be missed to:

(a) decrease distribution costs by avoiding or delaying distribution infrastructure investments. Cost increases would ultimately be paid for by consumers

(b) support climate targets by increasing the amount of renewable energy (RE) generation and load shifting (with batteries and demand response) to reduce peak demand. Reducing peak demand lowers emissions because more fossil fuels are used for electricity generation at peak times when there is not enough RE generation to meet demand.

What are the incentives?

5.23 Traditionally, distributors built, maintained, and upgraded physical distribution networks to ensure consumers had reliable electricity supply. Today, this is still the core business for distributors, and it is where they have the skills and capability.

5.24 NNS are starting to become viable, but most distributors have relatively little experience in this area compared to network solutions (see the Capability and Capacity chapter). There may be some status quo bias or inertia affecting the decisions to stick to network investments, as these are tried and tested.

5.25 There might be other incentives and disincentives on distributors to opt for NNS rather than network investments. In their feedback on the *2021 Discussion Paper*, and in their responses to the recent information request, some distributors described what they perceive as disincentives for choosing NNS:

(a) distributors must reliably deliver electricity to consumers. Even if an NNS would save money, distributors must satisfy reliability standards and NNS might be perceived as unreliable or as introducing problems into the system, particularly where there is less understanding or familiarity with NNS than there is with network investments. Distributors might also doubt that NNS providers will survive long enough to offer flexibility services for the period contracted.

(b) distributors perceive there is preferential regulatory treatment of capital expenditure (capex) versus operating expenditure (opex). Network investments are generally capex, while NNS are generally opex. These considerations are only relevant to the 16 distributors that are subject to price / quality regulation by the Commerce Commission, whereas the other 13 are only subject to Information Disclosure regulations.[111]

(c) some distributors also stated that if they only spend and recover opex, there will be no return to shareholder investment and hence no incentive to invest. This is perhaps a misconception about using NNS, because the profit should be a portion of the amount saved relative to investing in a network solution, and in the longer term, avoiding investing in network assets that become stranded.

5.26 Note that in respect of (b) and (c) above, the Commerce Commission is currently reviewing its input methodologies (IMs), which are the overarching rules, requirements and processes used by the Commission for services that are regulated under Part 4 of the Commerce Act. It is required to review the IMs at least every seven years. The Commission published a *Process and Issues* paper in May 2022 that identified some key focus areas for the review, including ‘Risk allocation and incentives under price-quality regulation.’ A draft *Framework paper* for the 2023 IM Review was also published in May. The Commission is now working through the submissions and cross-submissions to its consultation. It is also commencing the analyses required to further develop its views and draft decisions.[112]

[111] Several distributors have urged the Commission during its review to clarify the criteria for approving innovation incentives on projects that involve opex, such as NNS.

[112] See https://comcom.govt.nz/regulated-industries/input-methodologies/input-methodologies-for-electricity-gas-and-airports/input-methodologies-projects/2023-input-methodologies-review

Evidence to suggest there is an issue

5.27 In the submissions on the *2021 Discussion Paper*, it was unclear whether distributors preferring network investment over NNS really was an issue. Therefore, in February 2022, the Authority sent a follow-up Information Request to distributors, asking them to identify when and what NNS they had considered, what assessments they made, and where they had signalled the results in their AMPs.

5.28 Evidence that some distributors do see the benefits of NNS outweighing the benefits of network investments is provided by the examples of Aurora and Powerco, two large distributors that have procured flexibility services competitively.

5.29 A few other distributors have stated they will implement NNS in the medium term. On the other hand, a few distributors have said that whilst they do not have any fixed plans to implement NNS in the next three years, nevertheless they are considering NNS opportunities as a matter of course.

5.30 The information request also found that:

(a) several distributors say they do not have major capacity issues at present, so most network investment is driven by replacement and reliability. As such, there is limited consideration of either network investment or NNS to deliver new capacity

(b) some distributors say they do consider NNS but generally reject them as the supply side of the market is immature, or the solutions brought to them are not suitable, for example diesel generators, which produce high levels of greenhouse gas emissions. NNS are also seen as less reliable than network solutions owing to several factors, including the intermittency of the underlying DER or their dependence on unreliable subsystems such as real-time communications networks

(c) nevertheless, distributors are generally optimistic they will increasingly rely on NNS in future as the market matures, as their networks reach capacity, and as battery technology improves.

What is the scale of the issue?

5.31 The scale (and economic value) of this issue will depend on the number and value of NNS opportunities being missed, where the value is the saving from pursuing NNS relative to a more expensive network solution.

5.32 Again, the survey found the scale of the issue is, at least for now, relatively minor: networks are not constrained, the uptake of DER is still low, and some flexibility service provider offerings might not be viable or fit for purpose. However, as the uptake of DER increases and as the market matures, the scale of the issue is liable to grow accordingly, especially if behavioural and other biases towards capex continue to influence distributor choices between network investments and NNS.

5.33 On balance, the Authority identifies this as an issue that might become bigger as the market develops. Indeed, the Sapere CBA estimates the potential value of DER uptake increases progressively in the later years (e.g., from 2030–2050).

Possible options to address the issue

Option 1: Education and guidance for distributors on flexibility services

5.34 Education on flexibility services would include forums, workshops, and guidance material on the pros and cons of procuring NNS rather than investing in network upgrades.

5.35 This option would be industry-led with the Authority (and Commerce Commission) playing a coordination role where needed. The Authority may also commission the guidance documents.

5.36 This option is not recommended as the behaviour and submissions of distributors indicate they are alive to the issues and their importance and have built their own networks to share information; but more engagement between the Authority and distributors on the relative merits of NNS and network investments would be desirable.

Option 2: Fund trials and / or assistance with tender and contractual arrangements

5.37 Funding for trials would mean that distributors have room to experiment before adopting technology on a wider scale. The key here would be to avoid distributors replicating each other's trials rather than sharing results.

5.38 The Authority does not have the ability to fund trials, although some distributors have funded their own trials, for example Aurora's Upper Clutha solar project.

5.39 The emerging status of the market for flexibility services suggests distributors and flexibility traders alike would benefit from assistance with tender processes, and transactional and contractual arrangements.

5.40 Funding for these purposes could be available from MBIE if it would address the lack of maturity of flexibility services offerings and if this is partly due to high transactions costs (see also Chapter 6 on negotiating operating agreements).

5.41 The Authority would tentatively support funding of trials and / or assistance of the sort that might be available from MBIE, as mentioned above.

Option 3: Require distributors to show they have explored NNS

5.42 The Authority believes a requirement for distributors to show they have explored flexibility options for network investments over a certain size would help address this issue.

5.43 This approach could require distributors to submit or publish their assessments of the options so that a third party could evaluate the distributor's comparisons between, for example respective cost-benefit analyses. There is also a need for assessments to be comparable and to include all costs and benefits (such as the option benefit of flexibility). In this regard the UK's Energy Networks Association (ENA) published a common evaluation methodology (CEM) [113] which could be adapted for use in New Zealand.

5.44 Examples from other countries that have a similar objective include the requirement from 2023 for UK distributors that invest in capital grid upgrades of more than £1 million to show that a flexibility-based alternative solution is not a reasonable option.[114]

5.45 IPAG have recommended that directors of distributors be required (by the Commerce Commission) to sign an annual declaration to certify that the business investigated the use of DER for NNS.[115]

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[113] https://www.energynetworks.org/assets/images/Resource%20library/ON20-WS1A-P1%20Common%20Evaluation%20Methodology%20Background-PUBLISHED.24.12.20.pdf

[114] Greentech Media: How the UK Is Building Grid Markets to Reward Flexible Distributed Energy, 2020 https://www.greentechmedia.com/articles/read/how-the-uk-is-building-grid-markets-to-reward-flexible-distributed-energy

[115] Innovation and Participation Advisory Group: Equal Access, 2020 https://www.ea.govt.nz/assets/dms-assets/26/26594Equal-Access-IPAG.pdf

5.46 The Authority notes that these kinds of options will be able to be considered by the Commerce Commission as part of its targeted review of Information Disclosure requirements.[116]

5.47 The Authority will engage with the Commission to contribute to that review.

5.48 Under this approach it is proposed that the Authority could analyse and evaluate the information collected from distributors by the Commission and monitor those results over time, to assess whether distributors are making sufficient use of NNS.

5.49 The Authority's review could be publicly reported to provide wider transparency of the approaches taken across the distribution sector.

> **Q31. What are your views on the three options presented above, to deal with Issue 1 (that distributors might prefer network investments to NNS)? What alternative option/s would you favour, if any?**

Issue 2: Distributors may favour in-house NNS

5.50 Assuming distributors are convinced of the relative benefits of NNS over network investments in certain circumstances, the next question to consider is whether it matters if distributors prefer to self-supply NNS?

5.51 The alternatives are that distributors can choose to invest in flexibility services in-house (i.e., self-supply), sole-source them from a preferred provider, or issue a competitive tender for them. If distributors consistently prefer to self-supply flexibility services, then they (and therefore consumers) potentially forgo any benefits of competitive provision of these services. To a lesser extent, the same would apply to sole-sourcing, where a distributor appoints a supplier without ascertaining whether its offering is competitive.

5.52 In respect of flexibility resources (eg, grid-scale batteries, or public EV chargers), there is a potential concern around distributors owning these resources. Distributors would control how those flexibility resources are used and might not make the flexibility services associated with these resources available to all parts of the value stack. The concern is muted however, as distributors would likely account for most of the demand for these flexibility services themselves (85 % by value, according to the Sapere report).

Why is this an issue?

5.53 If distributors pursue flexibility in-house or through a subsidiary, they avoid procurement costs, get to keep control of the services provided, and can exploit any economies of scope that are available. The same could be true of flexibility resources: if distributors buy flexibility resources, then they will likely self-supply the associated flexibility services and exploit any economies of scope of doing so.

5.54 In the medium to long term, however, procuring flexibility services by competitive tender could well be cheaper than in-house options, though it remains to be seen whether the benefits of competitive procurement would outweigh any economies of scope available to distributors from self-supply.

5.55 If the market for flexibility services is not a level playing field, it will discourage market entry and competition. Competition should reveal whether third parties or distributors are the lowest-cost providers of flexibility services.

Evidence to suggest there is an issue

5.56 The feedback from the information request is that some distributors still favour self-supply of flexibility services, for a variety of reasons, including the view that third-party

[116] https://comcom.govt.nz/__data/assets/pdf_file/0028/289207/Targeted-information-disclosure-review-for-electricity-distribution-businesses-Tranche-1-draft-decisions-paper-3-August-2022.pdf

approaches to date have been for solutions that are not relevant or fit-for-purpose. Also, suspecting that third-party flexibility services may not always be able to be relied on to deliver,[117] distributors perhaps trust their self-supplied NNS rather than those of third parties.

5.57 On the other hand, several distributors did indicate their intention to make use of competitive tendering for NNS in due course – once the market is more mature, and once their networks need more capacity. Right now, some distributors say that they do not see themselves self-supplying NNS, as that would be a conflict of interest.

5.58 Note that while local government is encouraged to apply government procurement rules that might require consideration of competitive tenders for flexibility services by council-owned distributors, those rules would not prevent them tendering to purchase and own DER, such as batteries.

5.59 The Authority is somewhat concerned about this issue but would benefit from feedback via submissions on this paper. It seems several distributors would likely continue to favour self-supply, which could unnecessarily delay the development of the flexibility services market, and impede access to these services by Transpower, the system operator, and other potential purchasers in the value stack, which will ultimately delay or reduce the long-term benefits to consumers.

Possible options to address Issue 2 (that distributors prefer to self-supply NNS rather than use competitive procurement)

Option 1: Education and guidelines on competitive procurement and coordination

5.60 This option would involve education and seminars for distributors to raise awareness of the benefits of competitive tenders for procuring NNS, how to run competitive tenders, and how to ensure the focus is on shared goals of efficiency and savings with third parties, rather than on sharing the revenues associated with the project.

5.61 Procurement guidelines and contract templates could be developed to assist distributors if they choose to use them. This option is not preferred, as distributors appear to be aware of their options and are learning from each other, although several still appear to prefer the status quo.

5.62 However, as with Issue 1, more active engagement between the Authority and distributors on self-supply versus competitive procurement would be desirable.

Option 2: Enable multiple trading relationships

5.63 If flexibility traders have more routes to access consumer-owned DER, they should be able to make competitive offers to consumers without these having to originate from their existing retailer. This could greatly increase the investment in and uptake of DER by increasing the return or other value consumers could get from it. One possible solution is to implement multiple trading relationships (MTR).

5.64 Current market settings mean that consumers can transact with only one supplier, typically their electricity retailer. That limits consumer choice and control, and hinders competition, in circumstances where consumers have the ability to export electricity. For example, consumers with solar panels might want to be able to gift their surplus solar energy to other households, or sell it, but a retailer which offers competitive pricing for electricity supply may not offer these mechanisms for gifting or selling surplus solar energy, or may only buy it at uncompetitive rates. Therefore, it would increase competition if consumers could sign up with one retailer to purchase electricity and

[117] Owing to the intermittent nature of certain DER, e.g. small-scale solar PV without batteries.

another to facilitate gifting or sell electricity to. This is known as multiple trading relationships (MTR).

5.65 MTR (which is also referred to by the Authority as additional consumer choice of electricity services, or ACCES) should enable consumers and 'prosumers' (consumers who can also produce or generate electricity with DER), to save on the electricity they purchase from their peers and to make more money on power they sell to their peers.

5.66 To facilitate MTR, however, distributors (and MEPs) would need either Code changes or exemptions from the Code, because current regulatory settings allow only a single retailer at each point of connection or ICP.

5.67 Ara Ake[118] is conducting a pilot to evaluate the benefits of MTR and doing this via an off-market simulation (see Box 3).

5.68 Kāinga Ora[119] is also intending to run a trial of MTR which would share solar power between social housing units with solar panels and those without. This would require MTR if the two tenants had different retailers. The trial should provide some insight into the benefits of MTR, and potentially address an equity issue and contribute to mitigating energy hardship. For the trial to go ahead it would require a number of participants to obtain Code exemptions from the Authority, or alternatively a regulatory sandbox solution (see Box 3).

5.69 Changes will be needed to the information recorded in the registry and the switching process to facilitate the additional relationships consumers could have. The current back-office systems and processes, and cost allocation methodologies, may need to change to ensure the right people pay or get paid the right amounts at the right time.

5.70 MEPs may need to amend their systems if they are to enable this functionality. Similarly, distributors, retailers and other participants might need to amend their systems to account for an increasing number of participants.

5.71 There is a risk that if consumer uptake is slow, the benefits might not materialise or could be outweighed by the implementation costs, which would be recovered from consumers.

5.72 While more competition should drive down the costs of flexibility services being offered to distributors (and other buyers of flexibility), the impact on monthly consumer electricity bills of having more than one retailer is not yet clear.

[118] See www.araake.co.nz Ara Ake is New Zealand's 'future energy centre'.

[119] Kāinga Ora provides tenancy services to nearly 200,000 customers and their whānau and owns and maintains nearly 69,000 public houses while also providing home ownership products and other services. See www.kaingaora.govt.nz

Box 3

Potential benefits of MTR

MTR (multiple trading relationships) could improve competition in the sector, thereby benefiting consumers, and potentially mitigating energy hardship.

Members of the Authority's IPAG have advocated the use of trials to develop the mechanics of the market. MTR would enable consumers to transact with more than one electricity service provider at the same time and location, rather than being restricted to the services of only one retailer.

Importantly for this review of the distribution market settings, if MTR can facilitate competition and choice in the provision of flexibility services, then that should accelerate the uptake of DER by making it more attractive for homeowners to install DG, help reduce network congestion, and benefit the environment by reducing thermal electricity generation and related emissions.

The Ara Ake MTR trial

Ara Ake is conducting an off-market trial that relates to multiple trading relationships (MTR).

Ara Ake is considering how the trial, which involves several use cases, might be extended under the existing Code, perhaps with Code exemptions or a "regulatory sandbox" approach, where certain regulations or parts of the Code would be suspended for the participants for the duration of the trial. If the results of the trial are favourable, there will be parts of the Code that would need to be amended to enable the wider implementation of MTR.

The Ara Ake trial involves retailers, distributors, and industry associations as participants or observers.

It is an 'off-market pilot', in which participants will not interact directly with the wholesale electricity market, but market settings will be simulated as closely as possible, to provide equivalent services to the registry, reconciliation, and settlement functions.

The object is to explore how consumers can benefit from unbundled electricity services, especially consumers with DER such as rooftop solar and EV chargers.

Potential use cases range from: a farm with a large solar PV array; to a managed EV charging service; to a large employer wanting to share excess generation from rooftop solar with its workers; and energy sharing for social and Māori housing (funded by MBIE and Kāinga Ora).

The trial will run until April 2023.

The Kāinga Ora peer-to-peer (P2P) trial

Separately, Kāinga Ora has developed a trial that would allow the sharing of excess solar energy generated on certain social housing unit rooftops, with other units, for the mutual benefit of all the participating tenants in the area.

The financial peer-to-peer methodology proposed by Kāinga Ora might be described as 'MTR lite', as it requires fewer resources and no systematic overhaul of the Registry. It will, however, require Code exemptions for participating retailers and MEPs. It is hoped the trial will highlight any challenges and indicate the potential benefits of MTR in alleviating energy hardship.

Option 3: Encourage distributors to make 'standing offers' for DER (tentatively preferred)

5.73 IPAG recommended the Authority should encourage distributors to make available 'standing offer' price information for DER to support longer term alternatives to network investment.[120] This may include a list of offers based on the service and location and presented on a distributor's website. For example, a distributor might offer owners of solar a price per kWh for electricity fed back into the network at certain times of day.

5.74 IPAG's view was that the difference between controlled and uncontrolled use of system charges (for ripple-control hot water) is a standing offer for flexibility. Likewise, standing offers could be extended to other DER to kickstart the market.

5.75 DER owners and flexibility traders would have ready access to information on locations and network need so they can identify where they could assist if coordinated effectively with the distribution network operator.

5.76 This option is recommended, as it could be a quick and easy win and a step in the right direction towards market development.

Option 4: Monitor distributors' use of competitive procurement

5.77 The Authority considers useful information on distributors' reliance on competitive procurement versus self-supply could be obtained from the Commerce Commission.

5.78 As mentioned above, the Commerce Commission is conducting a targeted review of its Information Disclosure requirements for distributors. The Authority will work with the Commission in relation to what information would be helpful for this option, for example details of whether investments in NNS or flexibility resources are made in-house or procured competitively.

5.79 The Authority would analyse and evaluate the information collected from distributors by the Commission, and monitor those results over time, to assess the degree to which distributors are using competitive procurement for NNS. The information collected could be publicly reported to provide wider transparency of the approaches taken across the distribution sector.

5.80 The Authority tentatively supports this option.

Option 5: Impose Arm's-Length Rules on distributors involved in flexibility services

5.81 Based on monitoring the information collected under Option 4, it could be found that some distributors might still be reluctant to use competitive procurement for NNS. The Authority would then evaluate whether this was because third-party offerings were not forthcoming or turned out not to be fit-for-purpose. If it was apparent that third-party offerings were available which would deliver better outcomes than self-supply the Authority could consider extending its Arm's-Length Rules to require distributors to operate NNS through separate entities, and to deal with those entities on an arm's-length basis. [121]

5.82 Imposing arm's-length rules on distributors with respect to their NNS activities would preclude them from supplying NNS directly out of their existing distribution businesses. Now that the Arm's-Length Rules have been transferred from the Act into the Code, the Authority is in a position to consider extending the rules to cover relationships between distributors and businesses involved in flexibility services and / or flexibility resources.[122]

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[120] https://www.ea.govt.nz/assets/dms-assets/26/26594Equal-Access-IPAG.pdf

[121] There would be a range of ways such a requirement could be implemented, including grandparenting any existing NNS but requiring any new NNS to be implemented through an arm's-length entity.

[122] Section 109 of the Electricity Industry Act 2010, as amended by the Electricity Industry Amendment Act 2022, provides for the Authority to identify new types of industry participants by way of regulation.

This would potentially separate (or 'ring-fence') contestable services from the monopoly service of distributors (see Box 4 which sets out how ring-fencing has been applied to certain NNS in Australia).

5.83 The Authority might consider this option if distributors persist in self-supply of flexibility services and ownership of flexibility resources, and if this appears to be slowing the development of the market for flexibility services and, in turn, the uptake of DER.

5.84 The Council of European Energy Regulators (CEER) effectively recommends that distributors should not be involved in contestable services. Rather, they should act as neutral facilitators providing the information, system operation, network infrastructure and management functions.

5.85 It states (and note that the references to DSOs refer to the equivalent of distributors in New Zealand for the purposes of this discussion):

(a) 'To avoid market distortions, it remains essential that DSOs[123] are neutral when performing their tasks and are sufficiently unbundled. The greater the responsibilities given to the DSOs, and the more DSOs are involved in non-core activities, the greater the need for regulatory control or effective unbundling.'[124]

(b) 'When there is the potential for competition to develop across new activity areas, regulators usually have the option to either allow the DSO to undertake the activity under special conditions (imposed by the regulator) or disallow DSOs from undertaking such activity. The rationale for such regulatory intervention is twofold. Firstly, CEER believes competition is considered the best means to meet customer requirements in the most cost-efficient way; therefore, competition should not be impaired. Secondly, the DSO has access to lower cost capital which it can use to finance investment in competitive activities; this would be an abuse of the DSO's privileged position of having its cost covered by regulated tariffs, therefore providing it with an advantage to other market parties.'[125]

5.86 The Authority acknowledges the need for care with the timing of this option, as some distributors have submitted that they struggle to get fit-for-purpose flexibility service offerings from third parties.

5.87 Another risk in adopting Option 5 is that distributors might have economies of scope in self-providing NNS, or in owning flexibility resources, in which case these efficiencies would be forgone if they were forced to go to market for NNS.

5.88 On the other hand, the existence of economies of scope and whether they are real efficiencies, is yet to be demonstrated. The Authority is conscious that the advantages derived by distributors from better access to data than their downstream competitors, or from being in control of their competitors' connection times, are not real efficiencies and may reflect an abuse of market power.

Q32. Do you agree with the tentatively preferred intervention to deal with Issue 2 (Option 3: encourage standing offers) and the collection and monitoring of

[123] The term DSO stands for distribution system operator and has been avoided in this paper, as there does not seem to be consensus on its meaning in New Zealand. However, in this context a DSO can be seen as the equivalent of a New Zealand distributor.

[124] https://www.ceer.eu/documents/104400/5937686/ACER-CEER+White+Paper+3-European+Energy+Regulators+White+Paper+3+Facilitating+Flexibility+2017+05+22/4e03e0b4-0886-606d-b69b-ff48225e83f3

[125] https://www.ceer.eu/documents/104400/-/-/ef4d6e46-e0a5-f4a4-7b74-a6d43e74dde8

information proposed under Option 4? If not, what alternative option/s would you favour, if any?

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

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

5.89 The nature of this potential problem is that distributors could use their market power in their regulated services, to gain an advantage in one or more potentially contestable markets for themselves (including NNS, but also other markets that are not necessarily considered as NNS).

5.90 Distributors control essential inputs (especially data and connection) for several downstream markets and could impede the supply of those inputs – by means of outright refusal, or delaying supply of the inputs, or charging high prices for them.

Why is this an issue?

5.91 The concern here is completely different to that in Issue 1, which asks whether there is a problem with distributors discovering, by trial and error, whether self-supply or competitive procurement is the least-cost option for NNS in the long term. It is also different to Issue 2, which is that some distributors prefer to self-supply NNS.

5.92 Issue 3 arises where a distributor that prefers to self-provide NNS chooses to increase its involvement in NNS and / or other contestable markets by restricting access to those markets for third-party competitors.

5.93 Note that distributors might engage in such conduct in markets that, while related to distribution, are not necessarily markets for flexibility services, such as domestic solar PV or public EV charging stations.

5.94 In the case of solar PV, connecting these to the network is an example of a key input that can be withheld or delayed from third-party providers.

5.95 Next, we consider some strategies that distributors could use to exclude third-party competitors from these and other contestable markets.

Distributors could use information gained from their unique position as network operators to identify business opportunities to provide contestable services

5.96 Distributors receive Consumption Data as part of their regulated activities and are restricted as to how they may use that data.

5.97 Distributors could use their access to this data when they self-supply NNS, combined with their own data on their network capacity to give them a better indication than flexibility traders have, of where for example solar PV should be deployed / promoted next. It is hoped the solutions proposed in the data workstream will level the playing field somewhat.

5.98 Distributors use the Consumption Data and network capacity information to determine their network congestion and plan network upgrades. This is then included in their asset management plans (AMPs) which are made public. Third parties should then have access to this information, although the information contained in these AMPs may be delayed, incomplete or difficult to interpret.

5.99 Concerns were raised five years ago in a letter from ERANZ to the Commerce Commission, about the lack of information in AMPs.[126] Since then, there have been isolated instances of third parties referring to this sort of difficulty.

[126] https://www.ea.govt.nz/assets/dms-assets/24/2460001B-ERANZ-September-2017-Letter-to-ComCom-re-information-disclosure-limitations-with-redactions.PDF

Box 4

Ring-fencing of contestable services by the Australian Energy Regulator

Ring-fencing is the legal and functional separation of a distributor from a related business, and is designed to prevent regulated businesses from:

- discriminating in favour of their related businesses, to the disadvantage of competitors or potential competitors in these markets;
- using revenue earned from regulated services to subsidise contestable services.

In 2016, the Australian Energy Regulator (AER) published[1] its Ring-fencing Guideline (Electricity Distribution) (Version 1), which was applied across the Australian National Electricity Market (NEM). This sets out obligations applicable to distribution network service providers (DNSPs), with the objective to provide for the accounting and functional separation of the provision of direct control services by DNSPs from the provision of contestable services by them, or by their related businesses, and to promote competition in the provision of contestable electricity services. The Guideline also has a compliance reporting and breach reporting framework that is used to monitor compliance with the Guideline. Most obligations of the Guideline can be waived on application to the AER except for certain key obligations (such as the general obligation for a DNSP not to discriminate in favour of an affiliate).

In 2021, the AER published Version 3 of the Ring-fencing Guideline (Electricity Distribution), which commenced on 3 February 2022.

The AER's updated ring-fencing guideline provides the regulatory frameworks and controls that will support key emerging markets in Australia's transitioning energy sector: For example the deployment of batteries, including community-scale batteries, and regulated Stand-Alone Power Systems (SAPS – for example, solar panels, diesel generators and/or batteries).[1] The controlled and proportionate measures in relation to contestable services provided by these assets are in place to ensure DNSPs do not cross-subsidise them using their regulated allowances (paid for by their distribution customers) and thereby prevent third parties from competing in these markets.

Distributors might not connect third parties, and then 'gazump' their opportunities

5.100 Distributors might expedite connection for their subsidiary to execute a project proposed by, or tendered by, a third party. This involves exerting their control over the essential input of connection to the network, and also involves a conflict of interest, in that the third party must notify the distributor in its capacity as a potential competitor, of pending deals with consumers. This would frustrate the efforts of third parties to compete in the market for flexibility services, as consumers are likely to choose the quicker and easier option provided by the distributor.

5.101 Third parties must submit commercially confidential information to distributors when requesting to connect, for example, DER. Distributors could potentially use this information to inform their own business plans, investments, and target those same customers.

5.102 Part 2 of the Commerce Act (in particular, the prohibitions against anti-competitive arrangements, cartel conduct and misuse of market power), is enforced by the Commerce Commission, and may also influence distributors' decisions in respect of connecting third parties to their networks.

5.103 Ultimately distributors might decide they are not competitors or potential competitors of third-party providers of NNS, solar, batteries or EV chargers, but rather their partners in reducing network investment costs, as well as in sharing any revenues derived from these goods or services.

5.104 Most distributors responded to a particular question on this point in the Information Request by saying they do not regard relationships with third parties as competitive or contentious.

5.105 Nevertheless, it remains an open question whether the sharing of costs and revenues between distributors and downstream flexibility service providers is a matter of competition or collaboration – or a mix of the two. This is at the heart of Issue 3: will some distributors come to see these services as a competitive space and therefore potentially engage in exclusionary strategies to reserve these markets for themselves?

5.106 As the contestable markets for flexibility services, including grid-scale batteries, EV charging, solar generation, and perhaps other related goods and services develop, the need for coordination of buyers and sellers on one or more market platforms raises the further question of whether distributors can operate such platforms in a neutral manner, or whether only independent parties can do so. The Authority could wait and see whether distributors are predominantly competitive and adversarial, or collaborative towards third-party downstream service providers, before making that decision too soon.

Distributors might use revenue from their monopoly business to subsidise their activities in contestable markets

5.107 Using revenue earned from their monopoly services to fund contestable services could give distributors an unfair advantage over other competitors.

5.108 There are isolated reports of distributors using revenue from monopoly services to subsidise contestable services when these are not used as inputs to the regulated service. For example, free EV charging and free batteries could be seen as one-off pilot studies or demonstrations of new technology. However, if the conduct persists, it could be seen as an anti-competitive measure, designed to secure a first-mover advantage and foreclose any competition from third parties. Note, however, that distributors are unable to record ongoing subsidisation of contestable services like EV charging as a regulated service cost. So, if they use the revenue from the monopoly business to subsidise EV charging, for example, they will be taking it straight out of their profits (i.e., it would not increase line charges of non-exempt distributors).

What is the scale of the issue?

5.109 The Authority does not regard this as a serious issue at present.

5.110 Note that the Commerce Commission can address unilateral anti-competitive conduct, such as leveraging market power in the way described above, by applying Part 2 of the Commerce Act, in particular the revised Section 36, which will provide for both a purpose and an outcomes (effects) analysis of the relevant conduct.

5.111 In terms of potential responses by the Authority, there are two interventions proposed for consultation, the first of which is tentatively preferred, although Option 2 could be reserved for use as needed on a case-by-case basis.

Possible options to address Issue 3 (that distributors might use their monopoly position in distribution to secure an advantage in contestable markets)

5.112 The Authority has identified two potential measures to prevent or dissuade distributors from participating in contestable markets.

Option 1: Monitor the behaviour of distributors in contestable markets

5.113 Again, as referred to above, the Authority could rely on its monitoring of information disclosed to the Commerce Commission by distributors in respect of their Information Disclosure obligations, to determine the extent of distributors' activities in contestable markets. This information could be published to provide greater transparency of the approaches taken by different distributors.

5.114 The Authority tentatively supports this option and will continue to engage with the Commerce Commission on its targeted review of the Information Disclosure regime as it applies to electricity distribution businesses.

Option 2: Impose arm's-length rules on distributors involved in certain downstream contestable markets

5.115 A means of preventing the actual or potential anti-competitive leveraging of market power by distributors into specific contestable markets would be for the Authority to impose its arm's-length rules on distributors with respect to their participation in those markets. This approach could be considered if the monitoring approach set out under Option 1 identified that distributors were hindering or preventing competitive conduct in downstream markets.

5.116 Recent amendments to the Act have brought the Arm's-Length Rules into the Code and these could potentially be amended to require certain business activities to be conducted by a subsidiary or parent business, to which the Arm's-Length rules would then apply.

5.117 The Authority's view is that this intervention could be considered for contestable markets or market segments in which there have been instances of, or complaints about, anti-competitive conduct.

5.118 We would value your views on whether this would be a proportionate and reasonable option in contestable markets where there have been allegations of anti-competitive conduct by distributors.

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

6 Capability and Capacity

Introduction and scope

6.1 If the massive potential for DER indicated by the Sapere research is to be realised, there are several prerequisites, including significant uptake of DER, equal access to data, and sufficient human and financial resources. This chapter focuses on the latter – capability and capacity, as it relates to the availability of skilled staff to integrate DER and assess and implement NNS.

6.2 There are shortages of key skills that reflect general economic conditions, but these could become more acute as the demand for DER uptake increases and as distributors increasingly choose NNS projects. Enabling more collaboration and extending this to joint ventures between distributors could be a promising option for consideration, as it could multiply the availability of skills available to each distributor and increase the downstream opportunities for undertaking NNS projects.

Desired Outcome

6.3 The sector should have sufficient capacity to enable the significant uptake of DER as well as its connection and application to provide a dramatic increase in the supply of flexibility services, to facilitate the transformation of a low-emissions economy.

Status quo

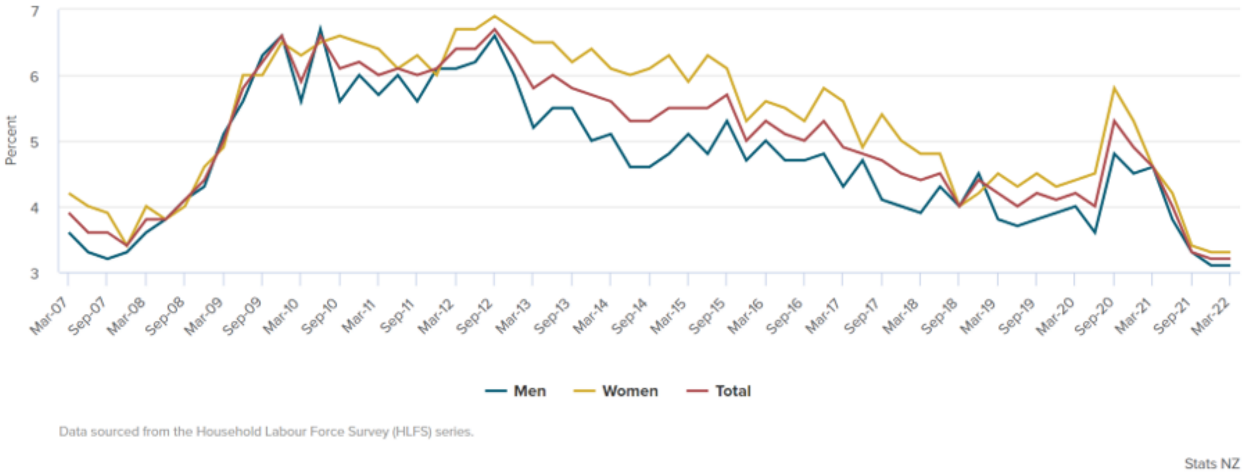
6.4 There are significant shortages of skilled personnel in the electricity industry and to a degree this reflects broader trends in the labour market. Unemployment in New Zealand has been falling gradually for the last ten years, and despite a Covid-related surge in 2020, fell to only 3.2 % in the March 2022 quarter (see Figure 8). This is exacerbating staff shortages in the electricity sector and is associated with rising wage costs and delays in the availability of key staff such as engineering contractors.

6.5 Research undertaken by the EEA in 2019 provided some details about the size of the problem facing the electricity supply sector and is relevant to electricity distribution, as 38 % of respondents were from the distribution sector.

6.6 Relevant statistics gleaned from that survey are as follows:

- age profiles by role indicated the 55–65 age group is overly represented in technician (21 %) and project management roles (27 %),with 23 % of engineers aged over 55.
- the contractor sector employed 88 % of trainee technicians, and the consulting sector employed 49 % of engineering trainees.
- gender analysis of the sector indicates males continue to represent over 87 % of all roles in the sector.

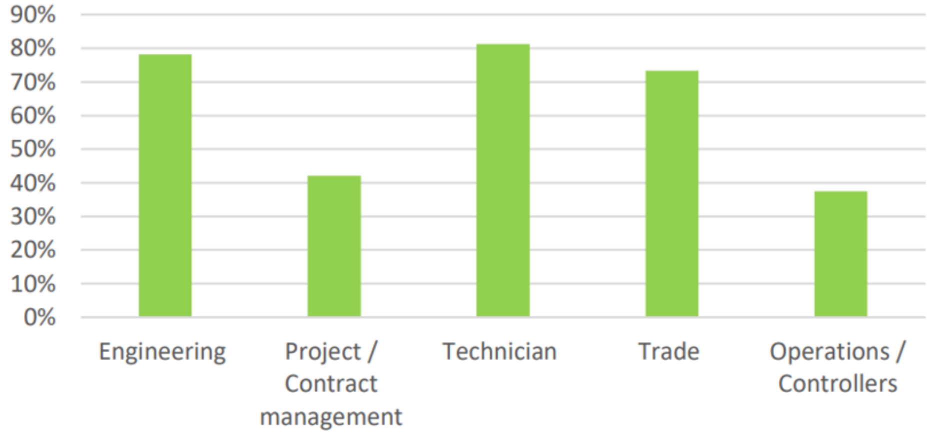
Figure 8: Unemployment rate by sex, seasonally adjusted, March 2007–March 2022[127]



6.7 In general, the survey concluded the ageing workforce is not being matched by new trainees to transfer over core skills. Organisations are struggling to fill roles, as shown in the graph below (Figure 9).

6.8 Another study on gendered employment trends[128] showed that while distribution had the highest share of overall employment in electricity, it had the smallest proportion of women (25.6 % in 2018).

Figure 9: Organisations finding it hard to recruit roles[129]



Problem definition

6.9 The electricity industry faces some difficulty in sourcing adequate capability and capacity. Distributors will need to transform their networks in the next ten years by integrating DER and drastically increasing capacity if they are to accommodate the increasing electrification of the economy. This is a mammoth task and engineering and related technical, IT, and project management skills (among others) are limited. Also, the fragmentation of distribution into 29 distributors multiplies the number of skilled

[127] Source: Statistics New Zealand.

[128] Julie MacArthur and Cathrine Dyer, 2021. Transition inequity: gendered employment trends in New Zealand's energy industries. *Policy Quarterly,* Vol 17 No. 3, August 2021, p31-38. https://ojs.victoria.ac.nz/pq/article/view/7130

[129] Source: EEA

personnel required to integrate DER and assess and implement the optimal network and NNS needed over the next ten years.

6.10 The potential problem is that without adequate access to skilled human resources, distributors will not be able to transform themselves fast enough or support the optimal mix of DER integration, network investment, and NNS projects in the overall growth required. Depending on the severity of the problem, there may be one or more interventions the Authority could implement to alleviate the capability and capacity issue.

6.11 Ideally, one would like to increase the availability of skilled engineers and technicians, whether by means of increasing the number of graduates or increasing immigration into New Zealand. However, the opposite is happening, with numbers of relevant personnel in the younger demographics merely replacing those in the older demographics who will retire soon; and New Zealand is battling to prevent skilled people from emigrating to other markets, never mind encouraging people to immigrate.

6.12 The *2021 Discussion Paper* asked distributors what they are doing to ensure their networks can transform efficiently and effectively, how they are working together in this regard, and whether more collaboration was needed. Through the relevant submissions the Authority noticed concerns around capacity and capability appeared to be a common theme emerging from the distributors' answers.

6.13 Submissions from distributors detailed several NNS initiatives, though there were some submissions from third parties that distributors were potentially delaying sector transformation by tending to defend their legacy assets and were not doing enough to innovate and manage electrification.

6.14 Distributors generally indicated they have been collaborating in various working groups and forums (e.g., the ENA), especially in the South Island. There have also been instances of joint EV trials and sharing of some strategies. Some submissions from flexible service providers disagreed, however, saying collaboration was missing.

6.15 Some distributors submitted that they were collaborating enough, and the Authority should indicate its expectations around any further collaboration. Some distributors anticipate further collaboration could involve distributors transitioning to become smart distributors and potentially trading platforms, which would require clarification in due course.

6.16 Other submissions from flexibility service providers noted a digital trading platform was required but that duplication across 29 distributors would be impractical. There was a concern expressed that collaboration between distributors could entrench the monopoly positions of distributors in respect of the emerging market for flexibility services.

Information Request

6.17 As a result of distributor responses following the release of the *2021 Discussion Paper*, an Information Request was sent to distributors including follow-up questions on the concerns around capability and capacity.

6.18 The questions were aimed at establishing the extent to which a lack of capacity or capability is a factor in deciding not to use NNS. Distributors were also asked to rank their reasons for not using NNS. Was this mainly because of capability and capacity, or was it more down to the emerging status of the flexibility services market, the superiority of network solutions, or the potential for contentious interactions with third parties? Finally, distributors were asked about the importance of three capability and capacity factors in their decisions not to use NNS: lack of skilled personnel; personnel have the skills but not the experience; and not enough collaboration between distributors.

6.19 The responses indicate some concern across distributors about the availability and cost of (mainly contracted) engineers and other skilled personnel, to assess and implement

NNS. However, these concerns did not seem to be any greater in respect of network services, than for sourcing engineering skills in any other sector of the economy, given the current tight labour market conditions in New Zealand.

6.20 The overall impression from the submissions on the *2021 Discussion Paper* and responses to the Information Request was capability and capacity is a minor issue, at least at this stage. The Authority tentatively accepts that but will monitor any developments in this regard.

6.21 To put the submissions into context, it is worth reflecting on the findings of the Authority's *2019 Review of distributors' capacity to respond to changing technology*.[130] We also spoke to representatives of the EEA for their point of view.

The Authority's 2019 review of distributors and the EEA's views

6.22 The *2019 Review* found distributors reported some difficulty in securing certain skills, but they did not see this as insurmountable, and distributors generally saw themselves as more innovative than other (non-electricity) sectors.

6.23 Most distributors cited a lack of management resources and a moderate level of difficulty in recruiting trade, technical and management staff. Some 78 % of distributors thought the lack of appropriate personnel was a barrier to innovation.

6.24 Distributors identified shortages of skills, particularly in management, customer service/sales, and (increasingly) data management. Candidates with IT skills including data science skills were difficult to find. The regional locations of some distributors made it difficult for them to attract candidates. In general, distributors found it difficult to recruit people with the necessary skills and training, across the electricity supply industry.

6.25 Nevertheless, the survey found distributors do not have a deficit in innovation activity relative to other industries, a good indicator that distributors can adapt to changes. The survey found almost all distributors collaborated on innovation with each other (rather than with stakeholders).

6.26 To get a more recent (post-Covid lockdowns) view about sector capability and capacity, we spoke with the Electrical Engineers' Association (EEA). They said NNS is a global market and so there is a worldwide shortage of the relevant skills. Therefore, the domestic shortage of engineers, line mechanics, cable joiners, IT staff and so on, might be exacerbated rather than alleviated by the re-opening of the borders following the Covid restrictions, as New Zealand salaries might not match what is available overseas.

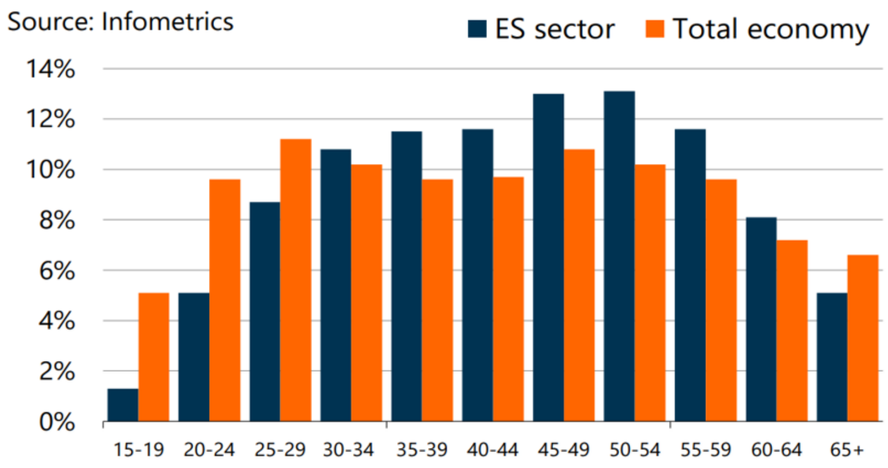
6.27 The EEA researched the skills pipeline and found the number of engineers in the younger demographic is not enough to cope with the increased size of the task, given the number of engineers who will retire in the next decade.

6.28 The chart below (Figure 10) is from an Infometrics report[131] commissioned by the EEA. It shows a key vulnerability of the electricity supply sector (denoted 'ES' in the chart). As mentioned earlier, the electricity supply sector relies heavily (relative to the economy as a whole) on employees in the older demographics. About 25% of industry employees were aged 55 and over in 2018, most of whom will retire in the next ten years.

Figure 10: ES Employment by age 2018

[130] https://www.ea.govt.nz/assets/dms-assets/25/25822Review-of-distributors.pdf

[131] Infometrics (April 2021). Environmental Scan for the Electricity Supply Industry, for Kohi Whakaaro, the Electricity Supply Industry Workforce Development Strategy. https://static1.squarespace.com/static/6110ae058b287208e9bf17ba/t/615e2e7ee1aa2027d16033c1/1633562240219/ESI+eScan+summary+FINAL+2021.pdf



Issue: Distributors have insufficient capability and capacity

6.29 Given the submissions and other evidence, we assess the potential problem of insufficient capability and capacity of distributors is serious enough to consider some options for intervention.

6.30 Potential interventions that are in the Authority's sphere of influence include encouraging more collaboration (and perhaps combining this with the training and education initiatives proposed in other chapters of this paper). However, longer-term interventions that are part of the wider government policies around building New Zealand's workforce and attracting skilled migrants, would need to be explored further in collaboration with the responsible agencies.

6.31 The Authority is of the view the following options are worth considering and we would like your views on them. These are among the options that were raised in the *2021 Discussion Paper*, or amended following submissions:

1) Encourage collaboration, training, and education
2) Encourage joint venture arrangements / regional clustering.

Option 1: Encourage collaboration, combined with training and education

6.32 The submissions by distributors made extensive reference to examples of their cooperation and collaboration with each other. For the most part, distributors were positive about these experiences, but they did not indicate they needed any further encouragement in that direction. In fact, one distributor asked the Authority what it thought more collaboration would look like.

6.33 On the other hand, there were a few submissions from third parties who were somewhat suspicious that distributors might collaborate on ways of sustaining their entrenched / monopoly position in the flexibility services market, to the exclusion of third parties. Some collaborative efforts might restrict competition. Distributors are in the same business as each other and would be potential if not actual competitors, were it not for their (historical and regulatory) status as separate monopolies.

6.34 It is possible that certain types of collaboration between distributors could involve discussions around ways of ensuring NNS work stays in-house and excludes third parties, which would not be desirable. Therefore, seeing as we are considering training and education efforts in respect of standards issues identified in Chapter 7, it might make sense to use that as a forum to discuss what further collaboration between distributors is needed and desirable in the future.

Option 2: Encourage joint venture arrangements (tentatively preferred)

6.35 This was an option proposed in the *2021 Discussion Paper* to address a 'medium issue'. It might multiply the available capability and capacity on an NNS project by the number of participating distributors, but also to aggregate the 'size of the prize' in terms of DER connections or flexibility services aggregated for a project.

6.36 If joint venture activity would benefit both or all participating distributors rather than excluding them or impinging on their reserved markets, it seems this could be a way of not only making a project viable, but also more affordable.

- For example, two or more geographically adjacent distributors could jointly provide or procure flexibility services aggregated in an area of geographical overlap between the distributors, and the project could be designed using the pooled expertise of both distributors.

6.37 Joint ventures are of course a form of collaboration and so this option is like the first option – 'encourage collaboration' – for it responds to the submission from one of the distributors, which asked "in what way should we collaborate more?" As such, the first two options could be combined.

6.38 The premise is that if the market for flexibility services is too small and under-developed, then allowing or encouraging joint venture activity could make participation in NNS more viable for sellers (DER and flexibility service providers) as well as buyers (distributors).

6.39 Costs would mainly be administrative expenses for the Authority to publicise the option and to set ground rules that would avoid any regulatory or competition law transgressions.

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

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

7 Operating agreements for flexibility services

Introduction

7.1 The Authority considers that there are no large issues with operating agreements for flexibility services to address at this point. The Authority does consider there will likely be value in providing some guidance on best practice, templates and / or standardisation, but considers that resource would be better prioritised to progressing the work in the other chapters. That said, where possible, the Authority will support industry-led work on this.

7.2 Submissions on the *2021 Discussion Paper* did not provide evidence of any issues associated with operating agreements for flexibility services. This might be because there are very few agreements for flexibility currently being negotiated, or it could indicate parties are too far apart commercially to enter negotiations. The Authority has not had any submissions from flexibility traders that they are facing such problems, but even if they are, this does not necessarily indicate there are problems with the agreement process.

7.3 The Authority supports the IPAG's recommendation from its *2021 Review of Transpower's Demand Response Programme*[132] that Transpower should work with Aurora and distributors more generally to agree a standard offer form for procuring flexibility as a NNS and enforce the use of this standard nationally for procuring non-network inputs through default agreements. The Authority agrees that this should occur and will monitor progress, but at this time will not mandate it. The Authority will also continue to monitor whether issues associated with operating agreements for flexibility services are developing, and any relevant overseas developments.

Scope

7.4 In this chapter, operating agreements are the contracts that detail the terms and conditions that apply to the flexibility services a distributor is purchasing from a flexibility trader (separate to connection agreements).[133] While operating agreements could vary greatly, there will be common provisions such as:

(a) a description of the type of flexibility services that will be provided and when they will be required (often described as the 'event' that triggers the need for the flexibility, which could be a change in the demand and / or supply of electricity)

(b) the amount paid for the flexibility service and the method for calculating payment

(c) flexibility trader and distributor obligations and general responsibilities

(d) confidentiality, dispute, *force majeure,* and termination provisions

(e) audit provisions to ensure compliance with the requirements of the agreements

(f) health and safety obligations.

7.5 This section considers whether:

[132] Microsoft Word - Transpower DR programme review - recs memo (IPAG template) (ea.govt.nz)

[133] A connection agreement generally refers to an agreement for DG to be connected to the distribution network. A connection agreement is 'passive', ie, does not make provision for demand or supply response to a signal from the network. An operating agreement is a 'dynamic agreement', in that it includes provision for demand or supply response and the various service levels surrounding that.

(a) the transaction costs associated with negotiating operating agreements for flexibility services between a distributor and a flexibility trader are unnecessarily high[134], and

(b) there is a power imbalance between distributors and flexibility traders in the negotiation of operating agreements for flexibility services.

7.6 These potential problems could prevent potential flexibility traders from entering the market or existing flexibility traders from expanding within the market by offering new services. They could also prevent distributors from seeking NNS, which might:

(a) Inhibit growth, innovation, and competition in the flexibility services market, and

(b) Lead to inefficient investments in addressing network issues.

7.7 This chapter is related to the market settings workstream. Like the market settings workstream, this workstream is considering whether guidelines, education and templates for operating agreements could support the uptake of NNS and competition for flexibility services.

Desired outcome

7.8 The process of negotiating operating agreements between distributors and flexibility traders for flexibility services does not impede the development of the market.

Status quo

What is the current state within which action is proposed?

7.9 The 29 distribution networks have monopoly rights to distribute electricity over their networks, while the market for flexibility services is contestable and comparatively new.

7.10 Distributors may provide flexibility services themselves or through a subsidiary company, or through an unrelated third party. Flexibility traders may either approach a distributor with an offer to provide flexibility services, or a distributor may go to market to procure flexibility services as an alternative solution to upgrading their network.

7.11 Aurora's agreement with solar Zero[135] for non-network capacity is an example of a flexibility service that has been fully procured by a distributor (Aurora) from a flexibility trader (solarZero). There are other examples of flexibility projects that are in the procurement stage, such as Powerco's Request for Proposal (RFP) for the Coromandel. Transpower have indicated that where flexible DER can provide Grid Support, they will tender and contract for this in the same way as any other Grid Support service.

7.12 Knowledge sharing on operating agreements for flexibility services is taking place within the distribution sector. For example, the Authority understands Aurora Energy's operating agreement with solarZero for their Upper Clutha project has been shared with other distributors.

How is the status quo expected to develop if no action is taken?

Transaction costs will fall over time

7.13 Due to the comparatively new nature of flexibility services in New Zealand and therefore limited contractual precedent, the Authority expects that operating agreements will initially require more upfront technical, commercial, and legal resources to draft and negotiate than if flexibility services were a more established market.

[134] While some distributors may not find these initial costs to be material to them (when compared to the overall cost of the project), they might be material for Flexibility traders and deter them from entering the market.
[135] solarZero - A cheaper, cleaner, smarter way to power your home. (solarcity.co.nz)

7.14 As flexibility markets become more liquid, it is anticipated that distributors will refine their negotiating process to an extent, for example some distributors would develop standard clauses in operating agreements for contracting with flexibility traders to provide services to their own network.

7.15 Similarly, flexibility traders will likely refine their negotiating process as they benefit from experience. The transaction costs involved in negotiating agreements are therefore expected to fall over time as certain contract provisions become standardised.

7.16 The Authority expects that as procurement practices develop and mature this will have positive impacts on negotiating operating agreements. This is because the requirements around flexibility services, and the general obligations and responsibilities for both distributors and flexibility traders will become clearer and more standardised during procurement which will flow into the negotiation of the operating agreement. Options to support the procurement process will be considered in the market settings workstream.

7.17 While distributors and flexibility traders are expected to continue to refine their individual processes and knowledge, a flexibility trader looking to expand across New Zealand would still need to engage with up to 29 different sets of agreements, which could be prohibitive.

The bargaining power imbalance could worsen

7.18 As the flexibility services market develops, it should become easier for a distributor to negotiate with multiple flexibility traders to find the best deal for themselves. However, flexibility traders will still have only the one distributor per region as a potential buyer for their services. This potentially strengthens the negotiating power of distributors relative to flexibility traders, though the welfare consequences are unclear. If distributors manage to use their bargaining power to procure flexibility services at least cost, then consumers should benefit, if those savings are passed on to consumers.

7.19 But if flexibility traders are burdened with disproportionate contract negotiation costs that make even their best bids less attractive than an investment in upgrading the network, then these contract costs could be contributing to inefficiency.

Problem definition

7.20 IPAG, in its *2019 Equal Access Report*, stated that transaction costs for facilitating flexibility services are high and the Authority should consider extending the default distribution connection and Use-of-System Agreements (UoSAs) for all types of network users.[136] A common theme in the feedback on the *2019 Project Spotlight on Emerging Contestable Services* was there was difficulty in forming a suitable contract between a distributor and a third party for services intended to support network performance.[137] However, no examples were provided.

Higher-than-necessary negotiation costs hinder growth in flexibility markets

7.21 Bilateral negotiations associated with negotiating individual operating agreements with each distributor could be considered a barrier to entry or expansion across networks by flexibility traders. A trader looking to expand its offering would be required to negotiate several separate operating agreements – one for each network they are looking to operate their service on.

7.22 ERANZ submitted on the *2021 Discussion Paper* that:

> "Flexibility service providers will include small start-up sized businesses. They have a lower capacity to negotiate with monopoly distributors and to deal with the

[136] PowerPoint Presentation (ea.govt.nz)

[137] Commerce Commission - Commerce Commission/Electricity Authority joint project – Spotlight on emerging contestable services (comcom.govt.nz)

complexities of 29 different regimes. High market entry costs could deter new players, lowering competition, and, therefore, the amount of innovation in the industry."

7.23 For a distributor, the transaction costs associated with negotiating a suitable operating agreement may be a deterrent to procuring flexibility services, therefore inhibiting growth in the market for flexibility. Alternatively, even if the costs are not considered material to the distributor, they may deter flexibility traders from responding to competitive tenders. Unsuccessful tenders would further deter distributors from going to market for flexibility services, also hindering growth in the flexibility market.

7.24 Less growth in the flexibility market will increase the cost of network services for consumers. This is because consumers will ultimately pay for network upgrades that are necessitated by the lack of any flexibility alternatives, or for the additional costs incurred in the negotiation process as flexibility traders build these into their pricing.

7.25 This problem is like one of the three issues the DDA sought to address as outlined in the *2020 Decision Paper*: 'higher than necessary costs and the need to negotiate multiple UoSAs introduces a barrier to traders entering and expanding across new distribution networks.'[138]

Bargaining power imbalance

7.26 As mentioned earlier, distributors may be able to dictate unfavourable terms to flexibility traders. This would be more likely to occur in a situation where there are many flexibility traders competing for very few opportunities to provide flexibility solutions to networks.

7.27 An uneven bargaining position was one of the three issues the DDA sought to address. In a retailer-distributor relationship, a distributor only needs one retailer to operate on its network to offer its distribution service. Each additional retailer wanting to trade on its network offers no additional benefit to the distributor. A retailer wanting to service consumers on a network has no option but to negotiate with that distributor to enter that market.

7.28 On the other hand, there is possibly less likelihood of a bargaining power imbalance between distributors and flexibility traders as there are incentives on distributors to conclude operating agreements, if the business case for seeking a non-network alternative is preferred when viewed against a lines upgrade (presuming that is the case, since they have taken steps to seek a NNS and proceeded to the contract negotiations).

On this point, Unison and Centralines submitted that:

> "we recognise that flexibility services will likely be capable of providing our consumer-owners with material benefits…in that respect we do not see how procurement of a flexibility service would differ from procurement of any other service.

Is there evidence to suggest there is a problem?

Responses to the 2021 Discussion Paper

7.29 No submitter on the *2021 Discussion Paper* stated they were experiencing difficulties in negotiating agreements for flexibility services. Several submitters commented that transaction costs could be a barrier but were likely to fall as the agreements become more common.

7.30 Submissions on the *2021 Discussion Paper* emphasised the market for flexibility services is comparatively new. One of the main examples of where flexibility services

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[138] *Default DistributorAgreement Decision Paper* (ea.govt.nz)

have been competitively procured is Aurora's Upper Clutha project with solarZero. In response to the *2021 Discussion Paper* each party commented:

> solarZero: "We would be in a much better position to answer this when we have had much more experience negotiating operating agreements."[139] "We see a need for some standardisation, but at this early stage we also see a need for innovation that should not be constrained by early-stage standardisation."
>
> Aurora: "While the agreement for flexibility services in the Upper Clutha took some time to develop, it was not unexpected."

7.31 Most distributors commented that standardising agreements would not lower transaction costs. Three commented that it was too early to do so. Alpine Energy commented: "As flexibility services is currently still in its very early stages, designing a standard operating agreement would be exceptionally difficult, costly and time consuming."

7.32 One retailer said a standardised agreement would not help. Three said that it would (but one commented that it is too early to do it in an affordable manner). Four third parties said that a standardised agreement would help, while one said no and that standardised terms would emerge over time.

7.33 While the submissions on the *2021 Discussion Paper* did not provide any evidence of issues associated with operating agreements for flexibility services, this could be because there are not many agreements being negotiated, or it could be that parties are too far apart to even begin negotiating. However, the latter would not be a problem that a standardised agreement could resolve.

IPAG Review of the Transpower Demand Response Programme

7.34 In the IPAG's *Review of Transpower's Demand Response Programme*, Transpower indicated that the future of their DR programme would be awards of a (specific type of) Grid Support Contract (GSC) which could accommodate establishment and / or availability payments. The IPAG explained how useful GSCs could be, in giving the market an opportunity to respond to the GSC tender with a potential solution.

7.35 Rather than leaving the form of offer to GSCs open, the IPAG recommended that the Authority require Transpower to work with Aurora and the distributors more generally to agree a standard offer form for procuring flexibility as a NNS and enforce the use of this standard nationally for procuring non-network inputs through default agreements. The Authority agrees that this should occur and will monitor progress, but at this time will not require it formally.

Next steps

7.36 The Authority considers that there is no issue to address now. The Authority does consider that there will likely be value in providing some guidance on best practice, templates and / or standardisation to help ensure that the barriers associated with negotiating operating agreements are low. Where possible, the Authority will support industry-led work on this.

7.37 The Authority will monitor progress between Transpower and the distributors more generally to agree a standard offer form for procuring flexibility as a NNS. Additionally, the Authority will continue to monitor whether there are any concerns around operating agreements, and any relevant overseas developments.

The Default Distributor Agreement

[139] In response to the question: Have you experienced difficulties with negotiating operating agreements for flexibility services?

7.38 If, at a later point, the Authority concludes that a standardised operational agreement for flexibility services is necessary and desirable, the DDA template could be used as a starting point for a solution to address. The DDA was introduced to address the following issues:

(a) higher-than-necessary costs and effort in negotiations,

(b) an imbalance of bargaining positions limiting retail competition and inhibiting innovation in distribution services, and

(c) concerns that access to contestable services was being inhibited by terms distributors were imposing in their UoSAs.

7.39 Even though the issues the DDA was designed to address seem to overlap with the potential issues with operating agreements and therefore a DDA-type option might seem worth pursuing, the DDA covers matters that concern the far more mature distributor-retailer relationship and addresses confirmed issues.[140] Also, the DDA was the end product of a long and extensively consulted process that commenced in 2010, which for the first time required a model UoSA.[141]

7.40 In the DDA decision paper, it was noted that there may also be contract negotiation problems among other types of network users. The DDA template was therefore structured so that the Authority could provide default agreements for other types of services (such as flexibility services) in future by appending extra schedules, striking out irrelevant schedules, and retaining the effect of any terms in the DDA that would be relevant to the flexibility arrangement (for example the dispute resolution procedures in the existing DDA).

Q37. Do you agree with the proposed approach to monitor progress between Transpower and distributors in developing standard offer forms for procuring NNS, and monitor whether issues associated with operating agreements for flexibility services are developing, and prioritise resource to progressing the other chapters? If not, why not?

Q38. Do you have any views on the best way the Authority can monitor whether issues associated with operating agreements for flexibility services are developing?

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

[140] The decision paper estimated that introducing the DDA would reduce transaction costs relative to the status quo of between $1.1m and $1.3 m per annum across the entire industry through lower technical, commercial and legal resources required to draft and negotiate distributor agreements

[141] Use-of-System agreement was the defined term in the Code for an 'agreement between a distributor and a participant trading on, connected to, or using the distributor's network or equipment connected to the distributor's network'. This term was revoked in July 2020 and replaced with 'Distributor Agreement'.

8 DER Standards

Introduction

8.1 This chapter considers the DER standards[142] that New Zealand may need to unlock the $6.9 b of net benefits identified in the Sapere report.[143] It responds to feedback on the Authority's *2021 Discussion Paper*, 2022 information request, and subsequent discussions with stakeholders.

8.2 In summary, the chapter considers:

- possible changes to DER connection processes, so DER can be connected more efficiently
- ways to improve the performance of DER, so it can realise greater value (eg, smartness).

Table 4: Proposed DER standards actions

Standards issue		Priority and target time, if progressed
1	Review Part 6 of the Code: *Connection of distributed generation*	High 1-3 years
2	Investigate whether the inverter Standard (AS/NZS 4777.2:2020 *Grid connection of energy systems via inverters, Part 2: Inverter requirements*) should be made mandatory	High 1-3 years
3	Work with stakeholders to improve the performance of smart products, particularly EV chargers	High 1-3 years

8.3 This chapter considers standards for DER connected to distribution networks. It is possible some of the standards discussed here also have relevance for DER connected to the transmission network.

Scope

The Authority's work on Future Security and Resilience (FSR)

8.4 The Authority's FSR work has identified standards as a short-term priority. This includes a review of Part 8 of the Code: *Common Quality* requirements and grid connection standards. As such, there is likely to be some overlap between the FSR work and the Authority's work on DER standards discussed here. The Authority will ensure that both workstreams are aligned as they move forward.

8.5 However, this chapter mainly discusses Part 6 of the Code: *Connection of distributed generation.* A Part 6 review could make DER connection more efficient. The Authority seeks your views on:

- a proposed review of Part 6 of the Code

[142] The term 'standards' is used broadly here, encompassing formal standards published by Standards bodies (e.g. AS/NZS, IEEE and IEC Standards), regulatory standards (e.g. Code requirements drafted by the Authority) and informal standards (e.g. industry guidelines).

[143] D. Reeve, T. Stevenson & C. Comendant (2021) *Cost-benefit analysis of distributed energy resources in New Zealand: A report for the Electricity Authority*, Wellington, New Zealand [Cost-benefit-analysis-of-distributed-energy-resources-in-New-Zealand-Sapere-Research-Group-final-13September.pdf] (page 25).

- the scope of such a review if it were to happen, including the areas of Part 6 that are most in need of change.

8.6 As it currently stands, Part 6 refers to DG only and not to DER and, for that reason, DG is the term mostly used below. However, as part of the Part 6 discussion, the Authority seeks your views on amending it to include DER.

Desired outcome

8.7 The objective is that New Zealand has the DER standards it needs to underpin a competitive, reliable, and efficient electricity industry for the long-term benefit of consumers.

Status quo

8.8 Part 6 of the Code sets out the application processes, connection requirements, and fees for DG. The last substantive review of Part 6 occurred between 2011 and 2015.[144] Recognising that most DG applications are small-scale, it implemented a streamlined connection process for DG of < 10 kW.

8.9 Based on submissions to the Authority's *2021 Discussion Paper* and subsequent discussions, stakeholders seek a Part 6 that:

- ensures a competitive, reliable, and efficient electricity system
- encourages DER uptake
- enables consumers to get the greatest value from their assets
- supports flexibility markets and value stacking
- assigns equitable costs and benefits
- supports market access and innovation
- creates a level playing field for participants
- promotes best practice.

How is the status quo expected to develop if no action is taken?

8.10 Part 6 of the Code was written when solar applications were fewer in number and mostly residential in scale. Today, solar DG applications are typically larger, with industrial and commercial-scale solar DG more common, and there is increasing activity in large-scale DG (eg, solar farms).[145] Distributors are processing more solar DG applications of greater complexity and dealing with increasing network challenges (eg, declining hosting capacity, competing applications).

8.11 Today the importance of DER is recognised. Some DER are controllable and have greater capability than uncontrollable DG and, if well supported, can deliver significant benefit for consumers. Ideally, Part 6 should be adapted to enable the evolving capability of DER to deliver benefits for consumers.

8.12 If the status quo continues, it will become increasingly difficult to process and connect larger-scale DG, and the connection and operation of all DG will be less efficient. This would increase costs and reduce benefits for consumers.

Problem definition

8.13 The Authority considers that Part 6 of the Code should be reviewed and updated.

Proposed scope for the Part 6 review

8.14 The Authority proposes including the following issues as part of the Part 6 review:

[144] https://www.ea.govt.nz/development/work-programme/operational-efficiencies/operational-review-of-part-6/outcome/outcome

[145] www.emi.ea.govt.nz and EA 2022 Information Request.

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

8.15 The Authority seeks your views on whether other issues should be added to the proposed Part 6 review, and whether some of the issues above should be removed from the scope. The following sections explore the above issues in more detail.

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

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

1) Amend Part 6 to explicitly include DER

8.16 Part 6 of the Code sets out the application processes to connect DG to networks, but does not refer to DER. The Authority seeks your views on whether Part 6 should be amended to specifically include DER. As DG can be considered a subset of DER, this would widen the ambit and complexity of Part 6.

8.17 A range of issues would need to be considered as part of this work, including the following:

- whether battery energy storage systems are DG – batteries are net-negative forms of energy storage, so although they can export electricity, they can also be considered sources of electricity demand
- how an amended Part 6 might respond, if at all, to the flexibility presented by DER. The current Part 6 is concerned with DG nameplate generation capacity only, and doesn't consider the ability of DER to shift generation and demand
- how an amended Part 6 might respond, if at all, to aggregate DER applications that exceed the thresholds for System Operator involvement.

8.18 The Authority seeks your views on the issues above and any other pertinent issues.

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

2) Amend Part 6 DG application processes

8.19 The Authority is considering whether changes to better respond to an increasing number of DG applications of increasing size and complexity, including large-scale solar (eg, solar farms) are appropriate.

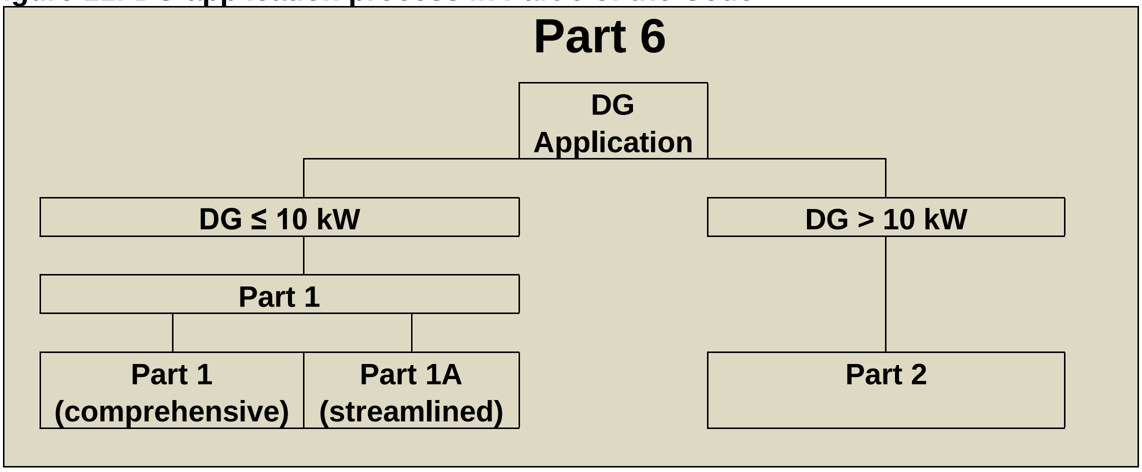
2a) Increase the Part 1 application process size threshold

8.20 The Authority is considering an increase to the size threshold for Part 1 applications, so a greater percentage of DG applications could be processed more readily and at less cost.

Status Quo

8.21 There are currently two DG application processes within Part 6 of the Code: Part 1 (DG ≤ 10kW) and Part 2 (DG > 10kW).[146]

Figure 11: DG application process in Part 6 of the Code



8.22 The Part 1 application process for DG < 10 kW has two options, Part 1 (comprehensive) and Part 1A (streamlined). Part 1A (streamlined) provides a simpler and quicker path to process DG and can only be used under certain circumstances (eg, it requires a Standards compliant, minimum level of inverter performance). The Part 2 application process (for DG > 10 kW) is more comprehensive than Part 1.

8.23 Part 1 is designed to enable the safe and efficient connection of small-scale DG. As the majority of DG applications are small-scale (see Table 4 below), it is important that Part 1 works effectively.

Table 5: Number of solar installations in New Zealand by size to 30 June 2022[147]

	DG ≤ 10 kW (Part 1)	DG > 10 kW (Part 2)
Number of solar installations	39,274	1,342
Percentage of total solar installations	96.7%	3.3%
Total capacity (MW)	165.5	52.2
Percentage of total solar capacity	76%	24%

8.24 The Authority has received feedback from distributors that Part 1 works well. It provides a relatively straightforward process for DG applicants, with the Authority advised by distributors that most small-scale applications now use the Part 1A (streamlined) approach.

8.25 The share of DG applications above and below 10 kW is expected to continue largely unchanged into the future. The number of small-scale DG applications will increase at a faster rate than larger-scale applications (DG > 10 kW). As more large-scale solar is progressed, DG > 10 kW could become a greater percentage of overall DG capacity.

Issues

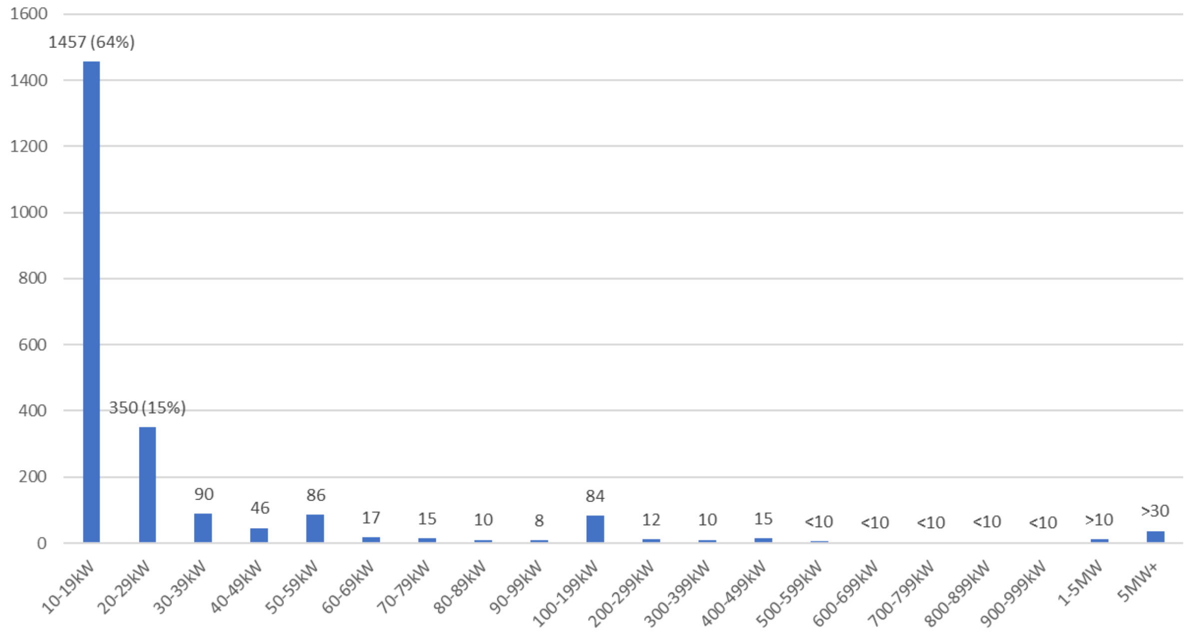
8.26 The Authority is considering whether the current 10 kW threshold for Part 1 is appropriate. As Part 1 is simpler and quicker than Part 2, there may be advantages to

[146] These should not be confused with Parts 1 and 2 of the Code.

[147] Solar makes up almost all DG applications. As DG connections are added to the Registry historically, the current DG numbers shown in EMI may differ slightly to those shown here. Source: EA EMI dashboards www.emi.ea.govt.nz

processing a larger percentage of DG applications through Part 1. Figure 13 below shows that if the threshold for Part 1 were increased from 10 kW to 20 kW or 30 kW, then most DG applications >10 kW could be processed through the simpler Part 1 process.

Figure 12: Number of >10 kW DG applications by size (mid 2019–mid 2022)[148]



8.27 The Authority proposes to consider the following questions if this proposal is addressed. We seek your views on these:

- is Part 1 suitable for DG larger than 10 kW? If the threshold were raised to 20 kW for example, would Part 1 need to change and how? Is there a size limit where no change would be required and, if so, is this preferable? Would Part 1 (comprehensive) be more suitable for this purpose than Part 1A (streamlined)?[149]
- What types of DG would be affected? Raising the Part 1 threshold may capture more small-scale commercial / institutional and rural installations (eg, farms)
- what would be the impact for network planning? – if there is greater throughput of DG between 10-20 kW say, how might distributors need to respond?[150]
- are the current Part 1 processing timeframes sufficient? Would these need to change and how?[151]

8.28 The benefits of this change could include increased DG uptake, lower DG application fees and shorter approval times. The Authority seeks stakeholder views on the extent of these and any other benefits, and potential drawbacks.

[148] Source: EA 2022 information request.
[149] eg, as Part 1 (comprehensive) provides more checks and balances than Part 1A (streamlined).
[150] Options might include, if the impacts were substantial enough, more proactive network planning, increased use of network modelling and forecasting, and greater application of maximum export limits.
[151] Many distributors are concerned about the ten business day threshold in S6.1.9 of the Code. This is discussed in Option 2b) below.

> **Q43. What are your thoughts on increasing the size threshold for Part 1 DG applications, including the benefits and drawbacks?**
>
> **Q44. If the threshold were to change, what do you think the new threshold should be and why?**

2b) Adjust the Part 1A (streamlined) processing time

8.29 The Authority is considering whether the timeframe to approve or decline a DG application via Part 1A (streamlined) should change.

Status Quo

8.30 The Part 1 (comprehensive) and Part 2 application processes allow distributors to seek time extensions to process DG applications, where reasonable. In contrast, the Part 1A (streamlined) process does not allow extensions. It requires a distributor to approve or decline a DG application no later than ten business days after it is submitted.[152] If this does not occur, the application is deemed approved.

Issues

8.31 A number of distributors say the ten-business day timeframe to process Part 1A (streamlined) applications is reasonable only if the volume of DG applications is low, the applications are not complex, and the hosting capacity of the network is abundant. Concurrent Part 1A applications for the same part of a network can be particularly challenging.

8.32 Other distributors say they easily meet the processing timeframe in Part 1A (streamlined), with some approving applications on the same day or shortly thereafter. This could be because they have relatively low numbers of DG applications and / or sufficient hosting capacity on their network. They may more actively model and plan for future network demand, and / or apply more stringent connection and operation standards.[153] They may also employ more staff to process DG applications.

8.33 It is important that the Part 1A process encourages the rapid uptake of DG and supports consumers to get the greatest benefit from their DG. The Authority seeks your views on whether the ten-business day timeframe in Part 1A (streamlined) should be adjusted (shortened or lengthened) and why. Submitters should also consider the case for change if the size threshold for Part 1 applications were to increase, as proposed in Option 2a above. We are particularly interested to hear how some distributors process Part 1A applications more readily than others.

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

2c) No change to Part 1 (comprehensive) and Part 2 approval timeframes

8.34 The Authority is considering not changing the approval timeframes in Part 1 (comprehensive) and Part 2.

[152] S6.1.9F.

[153] e.g. AS/NZS 4777.2:2020 states that inverters should have generation and export limit control, and that these capabilities shall be disabled by default.

Status Quo

8.35 Part 1 (comprehensive) requires a distributor to approve or decline a complete DG application within 30 business days of receiving it.[154] The distributor can seek several extensions of up to 20 business days each, and a distributed generator must not unreasonably withhold their consent for these.[155]

8.36 Part 2 sets the following timeframes for distributors to approve or decline a DG application:[156]

- DG less than 1 MW – 45 business days after receiving the final application
- DG 1 MW to less than 5 MW – 60 business days after receiving the final application
- DG 5 MW and greater – 80 business days after receiving the final application.

8.37 Part 2 allows distributors to seek successive time extensions of up to 40 business days each. A distributed generator must not unreasonably withhold their consent for an extension.[157]

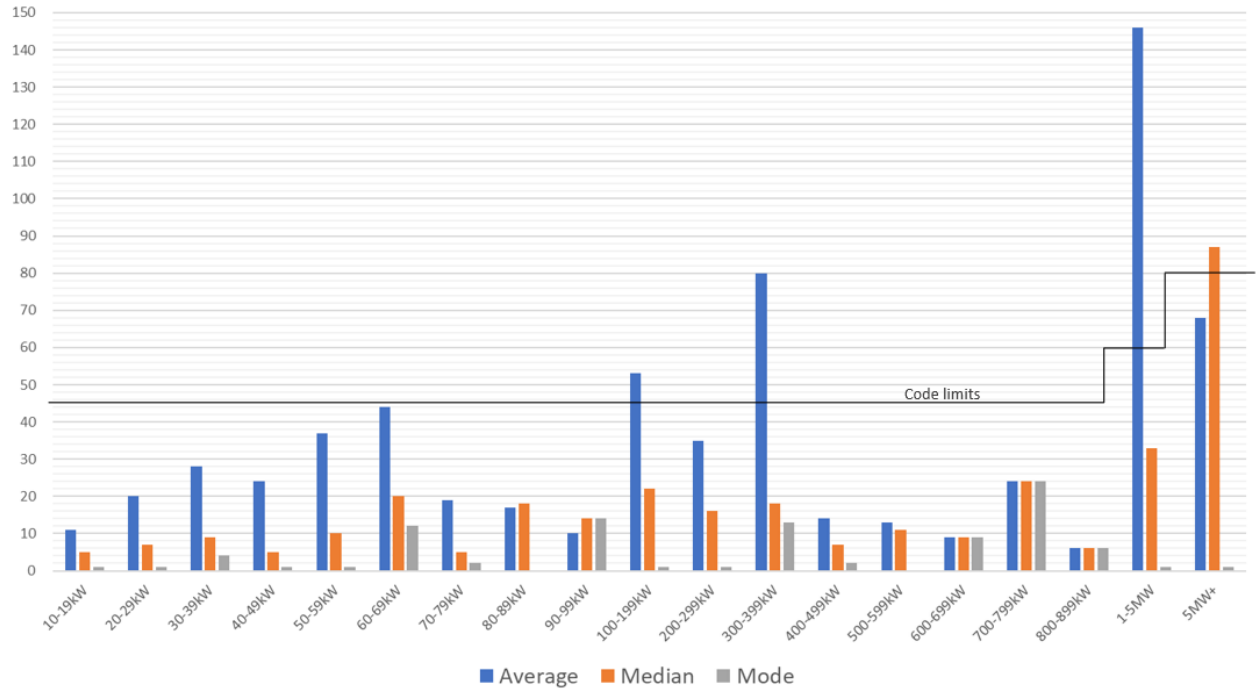
Issues

8.38 Many distributors seek longer approval timeframes for Part 2 applications. As Part 2 applications have grown in both size and complexity, some distributors say they are struggling to meet the statutory processing timeframes in the Code. This can be particularly challenging when concurrent applications are received for the same part of the network.

8.39 Figure 13 below shows the processing times for DG applications >10 kW from mid–2019 to mid–2022. It shows that most average and median times to approve DG >10 kW are within Code limits (without extensions).[158] However, the average time to approve 1–5 MW applications is somewhat longer, although this time can be expected to shorten as distributors and distributed generators become more experienced with applications of this size.

[154] Part S6.1.3
[155] Part S6.1.4
[156] Part S6.1.19
[157] Ibid.
[158] Also, the mode times show some applications are approved rapidly. This may be a function of how the application is processed eg, much of the pre-work being completed before the application is made.

Figure 13: Days taken to approve DG applications >10 kW by size (mid 2019–mid 2022)[159]



8.40 However, the maximum times to approve DG >10 kW can be sometime be extensive.[160]

Table 6: Maximum time to approve DG applications >10 kW by size

Size	10–19 kW	20–29 kW	30–39 kW	40–49 kW	50–59 kW	60–69 kW	70–79 kW	80–89 kW	90–99 kW	100–199 kW
Days	375	451	376	188	395	180	56	29	19	270
		200–299 kW	300–399 kW	400–499 kW	500–599 kW	600–699 kW	700–799 kW	800–899kW	1–5 MW	5 MW+
		160	406	41	32	9	24	6	730	97

8.41 The large-scale DER market is still emerging in New Zealand. Distributors and applicants are learning as they go, so early discussions can be exploratory, and it is common for proposals to progress slowly. Distributors and applicants often work collaboratively.[161] There are many opportunities for delay, and applicants can drop out. Although the Code sets timeframes to process applications, there is usually some give and take on both sides.

8.42 Despite the above, some distributors are concerned about the risks if applicants should start insisting on strict adherence to the approval timeframes in Part 2. They submit these should be lengthened. However, as distributors can seek multiple extensions, and a distributed generator cannot unreasonably withhold their consent for these extensions, the Authority does not currently see a strong case for change.

8.43 Maintaining the status quo of these timeframes is consistent with the views of most distributed generators. They submit that Part 2 is well established and, while there can be agreed delays, it works well as it stands. Distributors can seek time extensions, the

[159] Source: EA 2022 information request.

[160] Option 2d below discusses an option to include an additional application process for large-scale DG in Part 6 and this, if implemented, may require longer timeframes than the current Part 2 for approval.

[161] eg, distributors may assist applicants to progress their proposals for a time before applying the application fee, and applicants accept that delays can occur throughout the process.

work distributors undertake for one application can sometimes be used elsewhere, and the time distributors need to process applications can be shortened by fully considering flexibility in asset management plans. They also argue that many distributors could increase their internal capacity and capability to process DER connection requests.

8.44 The Authority seeks your views on maintaining the current approval timeframes in Part 1 (comprehensive) and Part 2.

Q46.	**What are your thoughts on maintaining the current approval timeframes in Part 1 (comprehensive) and Part 2?**
Q47.	**If you seek a change to approval timeframes, what evidence can you give to support this?**

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

8.45 Given their complexity, the Authority is considering adding a new application process for large-scale DG to Part 6.

Status Quo

8.46 At present, Part 6 provides a single application process for DG greater than 10 kW (Part 2). This means, for example, that an 11 kW application is treated much the same as a 1 MW (1,000 kW) application.

Issues

8.47 The Part 2 application process in its simplest form (flow chart) can be found in Appendix A of the Authority's guide *Connection of distributed generation (greater than 10 kW) to a local network*.[162] In practice, distributors say the process for larger-scale DG applications often deviates from the process set out in the EA guide, as the process is complex and multi-faceted.

8.48 Larger-scale DG is inherently more difficult to connect to networks than small-scale DG. It is more likely to require distributors and distributed generators to commission and respond to technical studies,[163] the use of specialist consultants, conversations with the system operator, and to trigger the testing/inspection and priority of applications clauses in Part 6.[164] It may require a network upgrade, land purchase and building / resource consents, and more in-depth contract negotiations.

8.49 In response to a number of submissions from distributors, the Authority is considering whether a new Part 6 application process is required for large-scale DG, to better respond to the complexity involved. However, the Authority has also received feedback from distributed generators and some distributors that the current Part 2 process is fine, and that the status quo should continue. Given this difference of opinion, the Authority seeks your views on this issue, including reasons why change may or may not be required.

8.50 In terms of where the threshold for a new application process might sit, if progressed, one option is 1 MW. This represents a relatively large DG system and is the size at which DG information must be provided to the System Operator through Part 8 of the Code. Some distributors have suggested a lower threshold, in the order of 300400 kW, saying this is the size at which the complexity and work associated with processing applications often steps up.

[162] https://www.ea.govt.nz/assets/dms-assets/24/24761Guidelines-for-connection-of-DG-greater-than-10kW.PDF
[163] e.g. feasibility studies, network and engineering studies.
[164] S6.1.17 and S6.1.22 of the Code.

8.51 A few submissions have suggested a further additional process for very large DG applications e.g., over 5 MW. Once again, the Authority seeks your views on this.

8.52 If a new application process is added for large-scale DG, changes could be made to the current Part 2 process, so it better responds to medium-sized DG applications (as often installed in the industrial, commercial, and institutional sectors).

8.53 A new large-scale DG application process, if progressed, would need to align with the relevant Parts of the Code (e.g., Part 8) and the Authority's FSR work.

8.54 The benefits and drawbacks of adding a new process for large-scale DG may include:

- potential benefits
  - a more efficient process for large-scale DG applications that provides the necessary level of assurance and reduces the need for rework, potentially delivering cost, time, and resource benefits
- potential drawbacks
  - some loss of productivity as the sector shifts to new application processes
  - risk of reduced DG investment if applicants perceive the new process as more onerous, time consuming and / or expensive.

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

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

2e) Review the priority of applications clause in Part 6

8.55 The Authority is considering a review of the priority of applications clause in Part 6.

Status quo

8.56 Part 6 currently has a simple process to prioritise Part 2 applications on the same part of the network.[165] If a distributor receives two applications within 20 business days of each other, the distributor may consider the final applications together as if they are competitive bids. The distributor can determine which application to progress, which *must* then take priority over subsequent applications.

Issues

8.57 Distributors have raised concerns about a 'race for capacity' with some DG applications highly speculative and exploratory in nature, which can be time and resource intensive for distributors. The say some applicants are 'land banking' and / or seeking to sell applications to the market once approved, with no intention to build, and some applicants seek to transfer incomplete applications to others mid-process. Applications can stall for a variety of reasons, sometimes beyond the applicant's control, but still retain priority. In the meantime, viable DG applications may be awaiting the distributor's consideration.

8.58 Distributors seek Part 6 changes to better prioritise DG applications, including the ability to queue connection requests and to focus on the most active proposals.

8.59 One option may be to create a framework (based on a range of criteria, eg, estimated date of supply, capacity, risk, level of progress) that distributors could apply to new and existing applications. This approach would take some discretion away from distributors,

[165] S6.1.17 of the Code.

which are best placed to determine how to connect DG to their network. It would also be challenging to determine and weigh the relevant factors to consider.

8.60 The benefits of amending the priority of applications clause may include:

- distributors can progress more DG applications and more quickly
- distributors can re-allocate their scarce resources to where they make the biggest difference
- distributors are better able to meet the Part 2 DG approval timeframes.

8.61 A potential risk is

- distributors could progress DG applications which are the easiest and/or of most value to the distributor.

8.62 The Authority recognises this is an important but difficult issue to resolve, having been considered but not fully resolved in previous years. Any change, if made, would need to ensure that all DG applications are prioritised fairly.

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

3) Strengthen Power Quality standards

Investigate the mandatory use of the inverter performance Standard AS/NZS 4777.2:2020

8.63 The increased uptake of DER presents both opportunities and challenges for New Zealand. A critical area of importance is managing Power Quality (e.g., frequency, voltage) to maintain electricity supply and support greater DER uptake. The Authority is considering whether the latest inverter performance Standard AS/NZS 4777.2:2020 should be made mandatory in New Zealand.[166]

Status quo

8.64 AS/NZS 4777.2:2020 sets the latest Power Quality performance requirements for inverters.[167] It was made mandatory for all new inverters in Australia in December 2021.

8.65 In New Zealand, AS/NZS 4777.2:2020 is required only for DG that uses the Part 1A (streamlined) application process. It is not required for Part 1 (comprehensive) and Part 2 applications.[168] It must also be used where required by distributors through their connection and operation standards, but currently only around half of distributors cite the latest version of the standard.[169]

Issue

8.66 The 2020 version of AS/NZS 4777.2 is a significant improvement over the previous version of the Standard. The main area of improvement is in security and Power Quality, with the introduction of new Power Quality response modes and passive anti-islanding requirements.[170] These deliver two key benefits:

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[166] The Authority is not able to reference ‘evergreen Standards’ where the latest version of a Standard would always apply in regulation.

[167] Inverters convert one form of electricity into another, most commonly from direct current (as generated by solar panels and stored in batteries) to alternating current (used in the wider electricity system, homes, and businesses).

[168] Code S6.1.1D

[169] Based on an Authority review of Distributor connection and operation standards.

[170] This includes new volt-var and volt-watt response modes, passive anti-islanding voltage and frequency limits, and sustained operation limits for voltage and frequency variations.

- to provide a staggered response to transmission-level events, so inverter systems can stay connected to the grid in these cases
- to adequately protect distribution networks from islanding.[171]

8.67 To future-proof the Standard, the 2020 Standard includes new references to energy storage, standalone systems and EVs, with the latter potentially valuable for when EVs export to networks. It also specifies requirements around external connections for EVs.

8.68 The benefits of mandating AS/NZS 4777.2:2020 could include:

- deferred investment in network upgrades – by improving the ability of inverters to respond to network issues
- greater DER potential – by lifting the performance of inverters across New Zealand
- greater consistency of distributor connection and operating standards
- support for the Authority's work on Future Security and Resilience (FSR) – through better management of inverters and Power Quality.

8.69 The drawbacks of mandating AS/NZS 4777.2:2020 could include:

- increased monitoring and compliance costs
- reduced value for some DER customers during periods of constraint – by limiting electricity generation and/or export
- reduced distributor and consumer choice – by requiring AS/NZS 4777.2:2020 compliant inverters[172]
- increased inverter cost – by requiring inverters to meet the latest Standard.

8.70 The impact of making AS/NZS 4777.2:2020 mandatory may be lessened by:

- the possibility that many inverters sold in New Zealand already comply with AS/NZS 4777.2:2020 as Australia and New Zealand share a common product market[173]
- the product lifetime of inverters (estimated at around ten years) – meaning older, less capable inverters will automatically be replaced by higher performing units as they fail.

8.71 The mandatory adoption of AS/NZS 4777.2:2020 may allow the removal of the Part 1 (comprehensive) application process from Part 6, simplifying the process for small-scale DG.[174] It may also provide some benefit for Part 2 applications.

8.72 The ENA has put a proposal to MBIE to raise the maximum allowable voltage limit in New Zealand, a change previously implemented in Australia.[175] If this change is adopted here, New Zealand has the option to pick up the relevant Australian values in AS/NZS 4777.2:2020.[176]

8.73 A regulatory impact assessment would be required to determine if there is a case for change. An alternative and simpler approach to regulation would be for all distributors to require the Standard through their connection and operation standards.[177]

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[171] Islanding is part of the network being electrically live and presenting risk to network users.
[172] Currently a distributor can choose to accept a lower level of inverter performance, which may be appropriate if it has a low number of DER applications and/or high hosting capacity.
[173] The Authority has not investigated to what extent inverter sales currently comply with AS/NZS 4777.2:2020.
[174] As previously noted, distributors tell the Authority most small-scale DG use the Part 1A application process.
[175] Increasing the maximum upper voltage limit from 6 % above 230 V to 10% above.
[176] eg, Tables 3.6, 3.7, 4.3. It is the Authority's understanding that most Australian jurisdictions have adopted the 'Australia A' settings.
[177] The option to use a practice note has been discounted as these are not mandatory and are typically used to interpret requirements only.

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

4) Review Part 6 prescribed maximum fees

Option 2a) Review the prescribed maximum fees in Part 6

8.74 The Authority proposes to review the prescribed maximum fees in Part 6. These have not changed since 2015.

Status quo

8.75 The prescribed maximum fees that a distributor can charge are set out in Part 6 of the Code and are included below. These fees cover a distributor's costs to process DG applications.

Table 7: Prescribed maximum fees in Part 6

Description of fee	$ (exclusive of GST)
Part 1 of Schedule 6.1 application	
Application fee under clause 2(2)(c)	200
Fee for observation of testing and inspection under clause 7(5)	60
Part 1A of Schedule 6.1 application	
Application fee under clause 9B(2)(c)	100
Fee for inspection under clause 9C(3)	60
Deficiency fee under clause 9E(4)	80
Part 2 of Schedule 6.1 application	
Application fee for distributed generation with nameplate capacity of more than 10 kW but less than 100 kW under clause 11(2)(c)	500
Application fee for distributed generation with nameplate capacity of 100 kW or more in total but less than 1 MW under clause 11(2)(c)	1,000
Application fee for distributed generation with nameplate capacity of 1MW or more under clause 11(2)(c)	5,000
Fee for observation of testing and inspection of distributed generation with nameplate capacity of more than 10 kW but less than 100 kW under clause 22(5)	120
Fee for observation of testing and inspection of distributed generation with nameplate capacity of 100 kW or more under clause 22(5)	1,200

Issues

8.76 The Authority has received feedback from distributors that the current fees are insufficient to cover their costs to process DG applications. This is particularly true for Part 2 applications which can require technical expertise[178] that comes at a cost that far exceeds the current fees. This shortfall in fees means that other network users are potentially cross subsidising the cost to process DG applications.[179]

[178] Often external consultants provide this technical expertise. Some large-scale DG applications near grid exit points may require the use of a Transpower approved consultant.

[179] Distributors are sometimes able to recoup the full cost of applications through connection fees, but only where applications progress to that stage.

8.77 The Authority proposes to review the prescribed maximum fees in Part 6 to ensure they are fit for purpose. This would require the Authority to consider the fee setting guidelines from Treasury, DPMC and the Legislation Design Advisory Committee.

8.78 Reviewing the prescribed maximum fees in Part 6 could:

- ensure distributed generators pay the full cost to process their DG application
- save other network users money, by removing the cross-subsidisation of DG application costs that currently occurs
- increase costs for distributed generators, with some reduction in DG applications possible.

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

Part 6 pricing principles

The Authority is considering the adequacy of the pricing principles in Part 6 as part of another project

8.79 The Authority has received feedback that the pricing principles in Part 6.4 need to be revised. In particular, stakeholders are concerned about the impacts of the 'incremental cost' rule on DG uptake.

Status quo

8.80 The pricing principles in Part 6.4 require distributors to charge incremental costs only. This approach allows distributed generators to connect to the network at incremental cost, until the hosting capacity of that section of the network is reached. Once capacity is reached, the next applicant seeking to connect will face substantial costs as a network upgrade is required. This is commonly known as 'first-mover disadvantage' and is more likely to be experienced by large DG applicants (as the size of their application is more likely to exceed the network's current hosting capacity). The costs can be even more substantial if a grid exit point is nearby, and a transmission upgrade is required.

Issue

8.81 Distributors seek a review of the pricing principles, including the removal of the incremental cost cap. They argue for fair cost allocation, where distributed generators pay a cost that reflects their current and future impacts on the network.

Next steps

8.82 This issue is being considered elsewhere as part of the Authority's work on distribution pricing,[180] which is running parallel to this work. As such, it is not part of the proposed Part 6 review.

8.83 This concludes the discussion on the proposed Part 6 review. The remainder of this chapter considers the importance of smart products.

Smart product standards

8.84 Smart products are important for a competitive, reliable, and efficient electricity system going forward. They are a key building block for flexibility markets, enabling the sector to move from *ad hoc*, manual control of DER products to large-scale, automated management of DER populations. This transformation will deliver a significant ramp-up in benefits for New Zealand.

[180] https://www.ea.govt.nz/operations/distribution/pricing

What are smart products?

8.85 In short, smart products have greater capability / controllability than normal products and can be managed remotely in real-time. More specifically, smart products can have the following features:

- interoperability and connectivity[181] – smart products can send and receive signals, and adjust their operation in response to those signals
- open communication protocols – authorised agents can engage with smart products, both directly and remotely
- visibility – smart products can display their status, readiness, and operation in real-time (or near real-time) to authorised agents
- smart capabilities – smart products have functions that can generate additional value, and support the efficient operation of the grid (eg, automated response to price signals, default off-peak charging mode with manual override)
- cyber security / privacy – smart products operate securely and protect sensitive information.

8.86 The path to smart products will occur over time, and it may be that products progressively adopt the capabilities listed above.

The Authority considers EV chargers to be the most important smart product to address at this time

8.87 The introduction to this report discussed the expected growth of EVs in New Zealand, and how this will drive a major increase in electricity demand over time. Without active management of EV chargers, New Zealand will face significant costs to meet this added demand. On a positive note, EVs offer more flexibility potential than all other products combined, with hot water the next most valuable.[182]

Status quo

8.88 Currently there are no smart product requirements for EV chargers in New Zealand. Sales of EVs and aftermarket EV chargers are increasing, impacting overall electricity demand.[183] Some distributors are managing local EV-related events (eg, where there are high concentrations of EVs on a street). To date, the market response is largely limited to EV tariffs,[184] offered by some retailers and designed to encourage charging outside of peak hours.

8.89 Internationally, there is strong interest in regulating the performance of EV chargers, in recognition of their importance to flexible electricity systems.

Issues

8.90 Without intervention, EVs and EV chargers will place a more significant burden on the New Zealand electricity system.[185] Peak demand will increase, requiring greater investment in new generation and transmission / distribution, and there will be more use

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[181] There are different definitions for interoperability and connectivity. Here we suggest interoperability is the capability of different electricity networks, smart devices, or smart device systems to connect and exchange information, and connectivity is the capability of a device to receive and react to external signals.

[182] Concept Consulting and Retyna (2021) *How New Zealand can accelerate the uptake of low emission vehicles Report 2: Consumer electricity supply arrangements, 5 October 2021*, Wellington, New Zealand https://www.concept.co.nz/uploads/1/2/8/3/128396759/ev_study_rept_2_v2.0.pdf

[183] Wellington Electricity estimates a small EV increases a typical household's electricity demand by about 35% (source: EV connect).

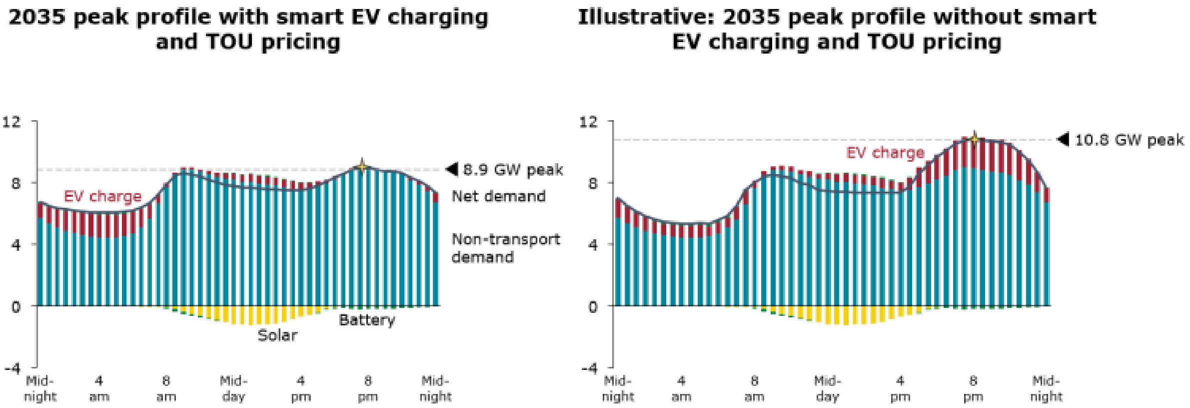
[184] eg, as offered by Meridian and Mercury. EV owners may also make use of free periods of electricity use, as offered by Contact and Electric Kiwi.

[185] Some natural improvement in product smartness can be expected without market intervention, and some consumers will respond to electricity price signals with or without the presence of smart products.

of thermal generation. This would place unnecessary costs on New Zealanders, as well as increase greenhouse gas emissions.

8.91 The illustration below, taken from a Transpower submission to MBIE, shows how smart EV charging in combination with time of use (TOU) pricing could reduce New Zealand's peak electricity demand by 2035.[186] In terms of the additional peak demand needed without intervention, the submission states: "if this 1.9 GW of peak capacity was to instead be met with gas-fired generation, the total cost of these gas generators and associated transmission and distribution infrastructure would be approximately $3 billion."

Figure 14: Illustration showing the potential value of DER and TOU pricing[187]



8.92 Internationally EV chargers are being regulated, with the UK being one recent example.[188] From 30 June 2022[189] EV chargers (called 'charge points' in the UK) for private charging must meet the following requirements:

- smart functionality, including the ability to send and receive information, the ability to respond to signals to increase the rate or time at which electricity flows through the charge point, demand side response services and a user interface
- electricity supplier interoperability, allowing the charge point to retain smart functionality even if the owner switches electricity supplier
- continued charging even if the charge point ceases to be connected to a communications network
- safety provisions, preventing the user carrying out an operation which could risk the health or safety of a person
- a measuring system, to measure or calculate the electricity imported or exported and the time the charging lasts, with visibility to the owner of this information
- security requirements consistent with the existing cyber security standard ETSI EN 303 645.

8.93 Charge points must also:

- incorporate pre-set, off peak, default charging hours and allow the owner to accept, remove or change these upon first use and subsequently
- allow for a randomised delay function.

[186] Transpower (2020) *MBIE Accelerating Renewable Energy and Energy Efficiency Consultation Submission*, Accelerating renewable energy and energy efficiency submission by Transpower (mbie.govt.nz)
[187] Source: Accelerating renewable energy and energy efficiency submission by Transpower (mbie.govt.nz)
[188] https://www.gov.uk/guidance/regulations-electric-vehicle-smart-charge-points
[189] By 30 December 2022 for security requirements.

The Authority will work with stakeholders to improve the performance of EV chargers

8.94 In recognition of the importance of EV chargers, EECA released a green paper in August 2022 titled *Improving the performance of EV chargers*.[190] This sought stakeholder views on whether regulation is required or not in New Zealand, what should be done to improve the performance of EV chargers, and the role of mandatory and voluntary standards.

8.95 The Authority has received much feedback on the importance of EV chargers in recent times and has reviewed valuable work undertaken by industry, concerned by the emerging impact.[191] The Authority has a strong interest in the results of the EECA consultation and is committed to work with EECA and other agencies to improve the performance of EV chargers. This will consider the respective roles and responsibilities of agencies, the smart product capabilities of benefit to New Zealand, when we might need these, and how the various agencies can work together to effect change.[192]

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[190] Energy Efficiency and Conservation Authority, (2022), Improving the performance of electric vehicle chargers, Wellington, New Zealand, a green paper by the Energy Efficiency and Conservation Authority Improving the performance of electric vehicle chargers | EECA

[191] e.g. the EV Connect work undertaken by Wellington Electricity https://www.welectricity.co.nz/about-us/major-projects/ev-connect

[192] EVs and EV chargers that export to the network will fall under the purview of Part 6, administered by the Authority. This is expected to occur in the next few years.

Appendix A: Format for submissions

Submitter	

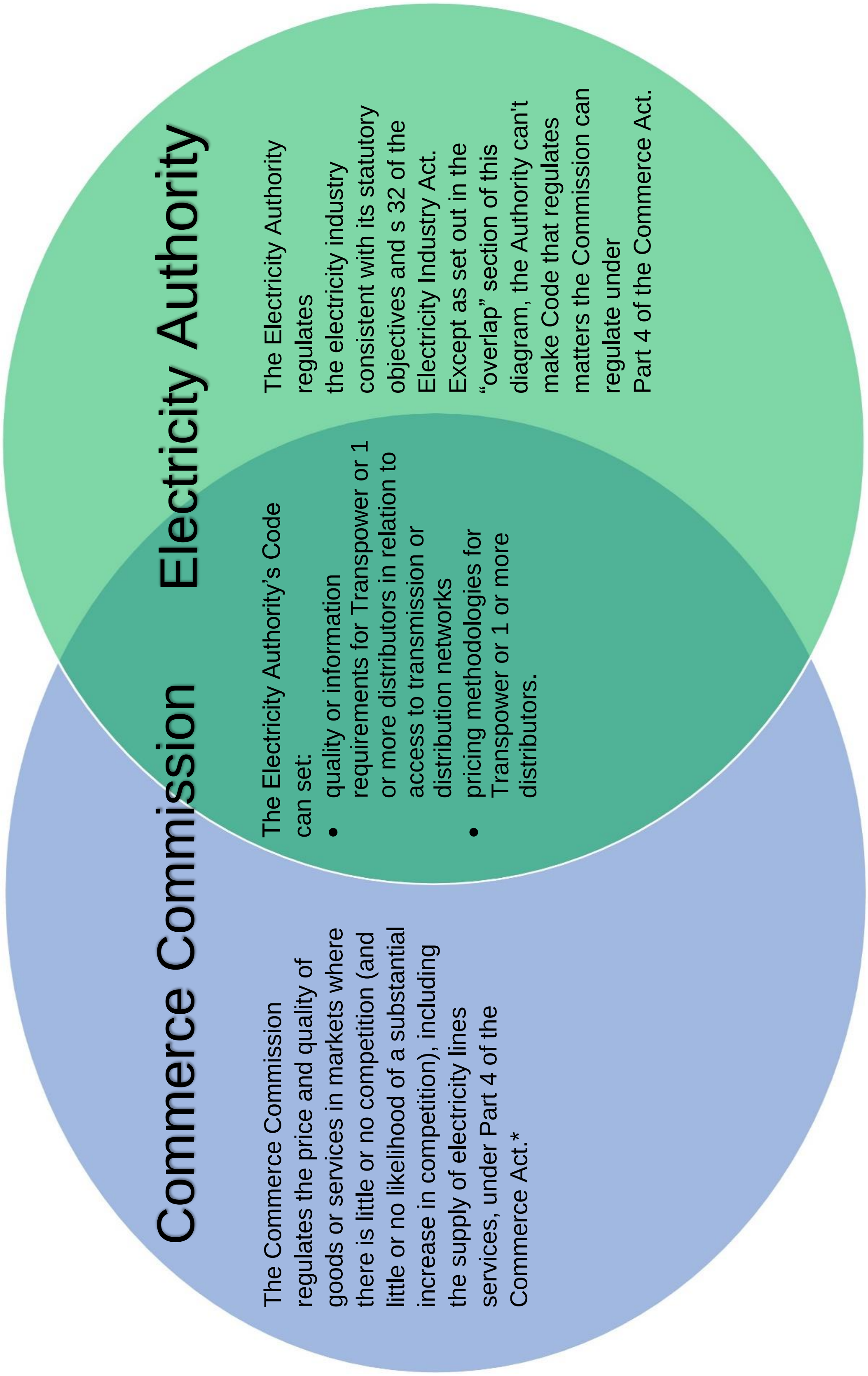
Question		Comment
Q1.	Do you see value in commissioning two separate reviews to look into the merit and practicalities of implementing the recommendations of the UK's Energy Data Taskforce around unlocking the value of customer actions and assets and delivering interoperability in a New Zealand setting?	
Q2.	Does this capture the key data needs for distributors to make informed business decisions that will unlock the potential of distributed energy resources (DER) for the long-term benefit of consumers? If not, what data is missing and what would it be used for?	
Q3.	Do you agree with the prioritisation of the key data needs for distributors? If not, why not and how would you suggest the priority is changed?	
Q4.	Does this capture the key data needs for flexibility traders to make informed business decisions that will unlock the potential of DER for the long-term benefit of consumers? If not, what is missing and what would the data be used for?	
Q5.	Do you agree with the prioritisation of the key data needs for flexibility traders? If not, why not?	
Q6.	Do you agree that the Authority should amend the Data Template to address the above issues to improve its workability? If not, why not?	
Q7.	Are there other changes to the Data Template that would improve it and assist it to be a useful mechanism for open access to data?	
Q8.	Do you agree that this is an issue? If not, why not?	
Q9.	Should the Authority amend the Code to clarify that MEPs can contract directly and provide both ICP data to distributors (and flexibility traders) for permitted purposes? If not, why not?	
Q10.	Should the DDA Data Template be updated to include Power Quality Data? If not, why not?	
Q11.	Do you think that the transaction costs associated with negotiating access to MEPs is a problem that the Authority should prioritise? If no, why not? If yes, do you think there is merit in developing a template to develop a default template to help reduce transaction costs?	
Q12.	Do you agree that MEP pricing for ICP Data (including Power Quality Data) and related data services is not unreasonable at this stage? If not, why not?	

Q13. Do you agree that MEP pricing for the provision of ICP Data to distributors (and other parties) could be more transparent? If not, why not?	
Q14. To support the transparency of pricing, standardisation, and equal access to data, do you think that the Authority should consider further implementing IPAG's Input Services recommendation that MEPs publish standard 'pay-as-you-go' terms open to all parties? If yes, why and what do you think this could cover? If not, why not?	
Q15. Do you agree that distributors' visibility of the location, size, and functionality of DER needs to be improved within the next 3–7 years to support network planning? If not, why not?	
Q16. Do you have any views on the type and size of DER that needs more visibility?	
Q17. The Authority acknowledges that definitions of 'real-time' vary, please explain what real-time data means to you.	
Q18. Do you agree that access to 'real-time' consumption and Power Quality Data won't be needed for at least five years?	
Q19. Do you agree that flexibility traders' access to ICP data must be improved so they have the same level of access as distributors (and retailers), with whom they might be competing to provide contestable services? If not, why not?	
Q20. Do you think the Authority should prioritise modifying the Data Template, so that flexibility traders can use it, or should the Authority prioritise amending the Code to clarify that MEPs must provide ICP data directly to flexibility traders and distributors for a set of permitted purposes without the need for retailer permission? If neither, please explain why.	
Q21. Do you agree that flexibility traders need access to granular current and likely future Congestion Data on distribution networks within the next 1–3 years?	
Q22. Are there any other issues preventing distributors from providing granular current and likely future congestion data?	
Q23. Do you agree that visibility of the location, size, and functionality of larger DER needs to be improved within the next 3–7 years to help understand the drivers of network congestion, what DER is 'controllable', and what services could be offered to owners of DER? If not, why not?	
Q24. Do you have any views on the type and size of DER that flexibility needs to have improved visibility?	
Q25. Do you think that the Authority, instead of a DER registry, should consider amending the registry data fields and / or requirements to improve DER visibility?	

Q26.	Do you agree that the Authority should prioritise work on addressing the other issues outlined in this paper?	
Q27.	Do you agree that flexibility trader access to real-time congestion and ICP data won't be needed for at least five years?	
Q28.	Do you agree that model privacy disclosure terms are appropriate?	
Q29.	Do you agree that model privacy disclosure terms would facilitate data access?	
Q30.	Do you see any practical issues with this proposal?	
Q31.	What are your views on the three options presented above, to deal with Issue 1 (that distributors might prefer network investments to NNS)? What alternative option/s would you favour, if any?	
Q32.	Do you agree with the tentatively preferred intervention to deal with Issue 2 (Option 3: encourage standing offers) and the collection and monitoring of information proposed under Option 4? If not, what alternative option/s would you favour, if any?	
Q33.	Do you think there are circumstances in which the Authority should extend the arm's length rules? If not, why not?	
Q34.	Do you agree with the Authority that Option 1 should be implemented, and that Option 2 could be considered in the event of allegations of, or instances of anti-competitive harm in contestable markets (Issue 3)? If not, what alternative option/s would you favour, if any?	
Q35.	What do you think of the Authority's option of using the education option proposed elsewhere in this paper, to include some guidance on how distributors should collaborate in future?	
Q36.	Do you think it would be helpful for the Authority to encourage the use of joint ventures between distributors to increase their integration of DERs and their procurement of NNS projects? And should this be combined with the first option?	
Q37.	Do you agree with the proposed approach to monitor progress between Transpower and distributors in developing standard offer forms for procuring NNS, and monitor whether issues associated with operating agreements for flexibility services are developing, and prioritise resource to progressing the other chapters? If not, why not?	
Q38.	Do you have any views on the best way the Authority can monitor whether issues associated with operating agreements for flexibility services are developing?	
Q39.	Do you have any suggestions for how the Authority can support industry-led work on providing guidance on best practice and templates for operating agreements?	
Q40.	What are your thoughts on the proposed scope for the Part 6 review? What, if anything, would you include or exclude, and why?	

Q41.	In order, what are the three most important issues that should be addressed as part of a Part 6 review, and why?	
Q42.	What are your thoughts on amending Part 6 of the Code to explicitly include DER, and what do you think are the key issues to be considered?	
Q43.	What are your thoughts on increasing the size threshold for Part 1 DG applications, including the benefits and drawbacks?	
Q44.	If the threshold were to change, what do you think the new threshold should be and why?	
Q45.	What are your thoughts on adjusting the ten-business day timeframe in Part 1A?	
Q46.	What are your thoughts on maintaining the current approval timeframes in Part 1 (comprehensive) and Part 2?	
Q47.	If you seek a change to approval timeframes, what evidence can you give to support this?	
Q48.	What are your thoughts on adding a new DG application process for large-scale DG to Part 6? Please provide examples in support of why you think change is or is not necessary.	
Q49.	If you think a new application process should be added, where should the threshold be and why?	
Q50.	What are your thoughts on reviewing the priority of applications clause in Part 6 of the Code?	
Q51.	Should the AS/NZS 4777.2:2020 Standard be mandated for inverters in New Zealand? If so, how should this be accomplished?	
Q52.	What are your thoughts on the Authority reviewing the prescribed maximum fees in Part 6 of the Code?	

Appendix B: The complementary jurisdictions of the Commerce Commission and the Authority



*Under s 54C(1) of the Commerce Act, 'electricity lines services' means:

- the conveyance of electricity by line in New Zealand; and
- with respect to services performed by Transpower, includes services performed as system operator.

There are a number of exclusions from in s 54C(2), which essentially cover generation, services that are subject to actual direct competition, and services excluded on the basis of their small scale.

Glossary of key terms

This glossary defines the key terms that are used throughout the paper. These definitions have mostly been taken verbatim from various sources such as IPAG advice, Ofgem and other industry work.

The Authority notes that there is debate about the exact definition for some of these terms. We note that the definitions will likely change and evolve over time and therefore they are not designed to be definitive for the industry. We also note that the FlexForum is working to develop terminology that can be adopted as an industry-standard – we support this work.

Demand Response (DR)	Demand response is a load management method that is used during periods of peak demand to relieve grid stress. For example, a charger or a load could be throttled to reduce energy consumption temporarily, until grid stress is relieved.
Distributed Energy Resources (DER)	Distributed Energy Resources (DERs) – small-scale, distribution-connected assets that either reduce load or export more power – whether generation (e.g., solar panels), storage (e.g., batteries), EVs, or technology to flexibly manage loads (such as water cylinders or pool pumps at the premises). DER can use, generate, or store electricity and form a part of the local distribution system, which primarily serve homes and businesses. Generation or storage DER mainly operate for the purpose of supplying all or a portion of the customer's electrical load but may also be capable of supplying power into the system or alternatively providing a load management service for customers. DER can also include front-of-meter small generation or storage located in lower-voltage parts of the network
(Controllable DER)	A subset of DER. Controllable DER's output or consumption can be turned on or off, or increased or decreased on demand – for example, diesel generation, batteries, and controllable EV chargers, but not intermittent renewable generation like wind or solar. Although when combined with storage, intermittent renewable generation can provide controllable DER. The impact of controllable DER is ***flexibility***.

DER Management (DERM)	The business process of selling, contracting with, operating, and paying for controllable DER portfolios.
DERM System (DERMS	The software and digital information flows that enable DERM by controlling DER.
Distributed Generation (DG)	Distributed generation is any form of generation connected to a distribution network, whether directly or indirectly via a consumer's electrical installation. Generally, DG is a type of DER.
Flexibility	The ability to modify generation and / or consumption patterns in reaction to an external signal (such as a change in price).
Flexibility markets / flexibility service markets	Mechanisms for matching and rewarding traders of controllable DER supply and / or demand on instruction or in response to prices.
Flexibility resources	Flexibility resources are DER assets such as batteries, solar panels and EVs. Flexibility resources can be used (controlled) to deliver a service. DER and larger resources like grid-connected generation or batteries can provide flexibility services. Distributed solar without a battery is not regarded as a flexibility resource because it is not controllable.
Flexibility resource owners	Owners of DER assets that can be used to provide flexibility services.
Flexibility traders	Traders who aggregate and manage portfolios of DER and buy flexibility services from their owners (unless they themselves are the owners), and then allocate (sell) the flexibility services derived from these DER to their highest value uses. Flexibility traders will in future increasingly endeavour where possible, to maximise the value of DER by allocating them to their highest value use ('value stacking') rather than a single use in terms of an exclusive agreement. Flexibility traders include commercial aggregators (aggregators who build flexibility portfolios of existing or new DER, eg, Enel X), parties that offer flexibility services using DER they own (eg, solarZero, distributors), and parties who are

	flexibility traders 'by accident' (eg, Contact purchased DER to manage NI reserves but is also using the DER in Transpower's DR programme).
Flexibility uses / the value stack	What flexibility is used for – including energy, ancillary services, transmission investment deferral, distribution investment deferral, outage restoration, etc.
Flexibility buyers	Parties (eg, the system operator, the grid owner, distributors, or retailers) who buy flexibility services.
Flexibility management	The business process of identifying need for, procuring, issuing operating instructions, and paying for flexibility services.
Flexibility Management Systems (FMS)	The technology that allows the flexibility manager to forecast and respond to the need for, procure, manage, contract for, issue instructions to check and reward flexibility providers.
Flexibility services	Services that take the flexibility available from controllable DER, and sell it on behalf of DER owners, to buyers of flexibility, at an agreed price, thereby fulfilling the demands for flexibility that are represented as the components of the value stack.
Flexibility trading platform	A market for trading (buying and selling) flexibility services, recognised by both buyers and sellers and operating according to agreed market rules, specifying for example the units to be traded, minimum quantities to be traded, how prices are to be set and how often, dispatch, settlement, etc. A flexibility trading platform might need to be an IT platform, especially if price-setting is dynamic and real-time and involves many buyers and sellers. The term flexibility trading platform implies this is a two-sided market (like for example card payment systems, where the platform sells cardholder services to consumers and acquiring services to merchants), but this is probably not the case: the flexibility that is sold is the same flexibility that is purchased, although there is the unusual feature that some participants may be sellers one day but buyers the next.

Non-Network Solutions (NNS)	NNS (or non-wire alternatives) are projects chosen to deliver flexibility services, as an alternative to investing in greater distribution network capacity.
Smart grid	An electrical grid which includes a variety of operational and energy measures including smart meters, smart appliances, renewable energy resources, and energy efficient resources. Electronic power conditioning and control of the production and distribution of electricity are important aspects of the Smart Grid.

Glossary of acronyms and abbreviations

Acronym	Definition
ACCES	Additional Consumer Choice of Electricity Services
AMP	Asset Management Plan
API	Application Program Interface
AS	Australian Standard
Authority	Electricity Authority
Capex	Capital expenditure
CBA	Cost Benefit Analysis
CDR	Consumption Data Rights
CEER	Council of European Energy Regulators
CERF	Climate Emergency Response Fund
CPP	Customised Price-quality Path
DDA	Default Distribution Agreement
DER	Distributed Energy Resource(s)
DERMS	Distributed Energy Resource Management Systems
DG	Distributed Generation
DPP	Default Price Path
DSO	Distribution System Operator
EDB	Electricity Distribution Business

EEA	Electrical Engineers' Association
EECA	Energy Efficiency and Conservation Authority
EIEP	Electricity Information Exchange Protocol
EMI	Electricity Market Information
ENA	Energy Networks Association
EPR	Electricity Price Review
ERANZ	Electricity Retailers' Association of New Zealand
ES	Electrical Supply
EV	Electric Vehicle
FSR	Future, Security and Resilience
FTP	File Transfer Protocol
GIDI	Government Investment in Decarbonising Industry
GSC	Grid Support Contract
GW	Gigawatt
GXP	Grid Exit Point
ICP	Installation Control Point
ID	Identification
IPAG	Innovation and Participation Advisory Group
IPP	Information Privacy Principle
IT	Information Technology
kW	Kilowatt
kWh	Kilowatt Hour
LV	Low Voltage

MBIE	Ministry of Business, Innovation and Employment
MEP	Metering Equipment Provider
MTR	Multiple Trading Relationships
MW	Megawatt
NNS	Non-network solutions
NZS	New Zealand Standard
Ofgem	Office of Gas and Electrical Markets
Opex	Operational expenditure
PV	Photovoltaic
R&D	Research and Development
RAB	Regulated Asset Base
RE	Renewable Energy
RFP	Request for Proposal
RIT-D	Regulatory Investment Test for Distributors
Totex	Total expenditure
TOU	Time of Use
TPM	Transmission Pricing Methodology
UK	United Kingdom
UoSA	Use-of-System Agreement
V2G	Vehicle-to-Grid
WACC	Weighted Average Cost of Capital