# Measures for Transition to an Expanded and Highly Renewable Electricity System

AUGUST 2023

MINISTRY OF BUSINESS, INNOVATION & EMPLOYMENT
HĪKINA WHAKATUTUKI

Te Kāwanatanga o Aotearoa
New Zealand Government

MINISTRY OF BUSINESS,
INNOVATION & EMPLOYMENT
HĪKINA WHAKATUTUKI

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# Have your say

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MBIE seeks written submissions on the issues raised in this document by **5pm on 2 November 2023**.

Your submission may respond to any or all of these issues. Where possible, please explain the reasons for your answer, include evidence to support your views, for example references to independent research, facts and figures, and include relevant examples.

Please use the submission template provided on the MBIE website. This will help us to collate submissions and ensure that your views are fully considered. Please also include your name and (if applicable) the name of your organisation in your submission.

Please include your contact details in the cover letter or e-mail accompanying your submission.

You can make your submission by:

- completing the survey on the MBIE website (recommended for shorter submissions only)
- sending your submission as a Microsoft Word document to electricitymarkets@mbie.govt.nz
- mailing your submission to:

Electricity Market Measures submissions

Ministry of Business, Innovation & Employment

PO Box 1473

Wellington 6140

New Zealand

Please direct any questions that you have in relation to the submissions process to electricitymarkets@mbie.govt.nz.

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# Ministerial Foreword

We need to do things differently if we are to avoid the impacts of climate change. To play our part in limiting global warming to 1.5°C, the Government has committed to reaching net zero for all greenhouse gas emissions (excluding biogenic methane) by 2050.

Reaching this goal will require a substantial and coordinated effort, and a commitment from across government that we are not shy of making. The Government is focused on the long-term strategic work of system change to a high performing, low emissions future.

The energy system has a critical role to play. In 2021[1], emissions from energy made up 40 per cent of New Zealand's total gross emissions. Cutting emissions from energy is essential to meeting our international climate commitments and reducing the impacts of climate change.

New Zealand is coming from a strong starting point, with a highly renewable electricity system New Zealanders can be proud of. Compared to many other countries, New Zealand's energy sources are highly reliable, renewable, and affordable. The challenge now is to increase the share of renewable energy, while providing affordability and reliability.

The Government has already made substantial progress in decarbonising the New Zealand energy system, including through the Government Investment in Decarbonising Industry programme, improvements we have underway to speed up consenting for new renewable generation, and the Warmer Kiwi Homes programme to reduce New Zealand's energy use while providing healthier homes.

To further this work, I am now releasing a package of consultation papers, each addressing a different challenge in the energy transition.

This issues paper looks at how we can ensure New Zealand's electricity system is affordable, reliable and resilient while we transition to an expanded and more highly renewable system. New Zealand meets much of its energy needs by producing energy domestically. Expanding our highly renewable electricity system will strengthen our energy independence and ensure our energy supply is affordable in the face of global shocks. A key issue for the energy transition is how to manage the phase out of fossil fuels in the electricity system, while responding to substantially increased electricity demand that is occurring through the electrification of other sectors (such as industry and transport). The paper sets out work already underway by government and relevant regulators and seeks feedback on what else might need to be considered.

I welcome your feedback on this document. Your insight will inform our pathway to an energy system that is secure, affordable and climate resilient.

Hon Dr Megan Woods
**Minister of Energy and Resources**

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[1] Ministry for the Environment. (2023, 13 April). *New Zealand's Greenhouse Gas Inventory 1990–2021 snapshot*. Ministry for the Environment. Available at: https://environment.govt.nz/publications/new-zealands-greenhouse-gas-inventory-19902021-snapshot/#new-zealands-gross-and-net-emissions

# Executive Summary

Aotearoa New Zealand is undergoing a once in a lifetime transition to an expanded and more highly renewable energy system. The electricity system will play a key role in reaching the Government's 2050 target for net zero emissions of long-lived greenhouse gases, and 2035 target for 50 per cent of energy consumed to come from renewable sources. Likewise, electricity will provide an increasingly important role in the wellbeing of energy-users – and in meeting basic needs such as heating and transport in an affordable and equitable way. To facilitate this, the electricity system needs to remain fit for purpose.

New Zealand's energy system has served us very well. Compared to many other countries, New Zealand's energy sources are highly reliable, renewable, and affordable. The challenge is to increase the share of energy used that is renewable, and increase the supply of energy, while maintaining and improving affordability and reliability.

Direct electrification, such as swapping fossil fuel vehicles for electric ones, will play a major part. While New Zealand already has a high share of renewable electricity, we need to build substantially more by 2050 to enable electrification. At the same time, we also need to ensure that the electricity system relies less on burning fossil gas or coal to manage times when there isn't enough renewable electricity available, due to peak demand or intermittency. Reducing reliance on fossil gas and coal for electricity generation will help to cut emissions and lower costs in the electricity system over time. This *Measures for Transition to an Expanded and Highly Renewable Electricity System* issues paper builds on significant existing work to help decarbonise our energy and electricity sectors. Since 2019, the Government has developed its first Emissions Reduction Plan (ERP), which incorporates and builds on many proposals in the Government's 2020 *Accelerating Renewable Energy and Energy Efficiency* consultation. These include:

- progressing improvements to 'national direction' instruments for renewable electricity generation and transmission infrastructure to speed up consenting
- boosting funding for the Government Investment in Decarbonising Industry (GIDI) Fund by $650 million over four years in Budget 2022, which is helping to decarbonise industry
- utilising the GIDI Fund, announcing a significant electrification partnership with New Zealand Steel in May 2023 that could reduce New Zealand's emissions by 1 per cent
- supporting community energy projects through the Māori and Public Housing Renewable Energy Fund.

This paper relates to an action in the Government's first ERP to investigate the need for measures that support affordable and reliable electricity supply, while accelerating the transition to a highly renewable electricity system. This issues paper sets out the new challenges for our electricity system as we transition. It also sets out the wide range of initiatives and developments underway and planned to help address these challenges. It includes information on measures being used and developed to address similar challenges in countries outside of New Zealand. This paper seeks your feedback on challenges and priorities in a range of areas – across generation, transmission, distribution, and end use.

The paper seeks feedback on whether there are any gaps in which further or alternative measures may need to be developed to support a successful electricity system transition. While this paper describes potential measures and approaches being considered in other countries, these are included to illustrate what could be done and to seek feedback on which measures should be considered in more detail in the future.

The **Introduction** outlines features of New Zealand's energy and electricity systems, as well as key challenges for transition. It outlines how this discussion document fits under the Energy Strategy currently being developed, and alongside other related workstreams.

Part 1, **Growing Renewable Generation**, is about ensuring sufficient renewable generation is built to electrify the economy and about how we replace the roles currently played by fossil fuel generation in a way that maintains security, reliability and affordability. Work is underway to review national direction instruments for renewable electricity and transmission infrastructure to make consenting easier.[2] In addition to this work, we seek feedback on a range of potential barriers to accelerating development of renewable electricity. Within Part 1:

- Chapter 2 **Accelerating supply of renewables** is about how to enable the investment in new renewable generation needed for electrification. The chapter seeks feedback on whether current approaches for new generation build are sufficient or whether further measures may be needed to support development of new renewables during transition. The chapter outlines examples of measures considered overseas to de-risk investment, such as power purchase agreements or contracts for differences. It notes that the scope of need for such measures is unclear, and it would be important to ensure that any further measures result in investment in addition to what would be built anyway.
- Chapter 3 **Ensuring sufficient firm capacity during transition** discusses the crucial roles currently played by fossil fuels. As fossil fuel plants retire, and the electricity system faces periods of high demand or low sun, wind or lake levels, there is a need to ensure we have sufficient generation to call on to meet peak demands and to 'firm' intermittent renewables. This chapter considers the need for firm capacity that can support expansion of our electricity system during transition, whether fossil gas-fired (if needed in transition), or through alternatives such as battery storage. It outlines work underway in New Zealand and overseas on this issue. It asks whether New Zealand may need additional measures to ensure sufficient peaking and firming capacity until technologically feasible renewable solutions are available.
- Chapter 4 **Managing slow start fossil fuel capacity during the transition** focuses on ensuring an orderly exit from current fossil fuel electricity generation. It outlines work underway by the Electricity Authority (Authority) to mitigate any security of supply risk if a fossil fuel plant retires in a sudden or disorderly way. The chapter seeks feedback on whether any further measures should be considered to support managed phase down of existing fossil fuel electricity generation for security of supply during transition.
- Chapter 5 **The role of large-scale flexibility** asks whether we have the right settings in place to incentivise the provision of efficient large-scale flexibility as a form of firming from industrial users and the maintenance of existing ripple control by distributors. It seeks feedback on what mechanisms could be further considered to incentivise demand response from industrial consumers, distributors, and retailers.

Part 2, **Competitive Markets**, considers the competition issues that may arise in the electricity market during the transition away from fossil fuels. Within Part 2:

- Chapter 6, **Workable competitive electricity markets**, draws on the Authority's wholesale market review and the Market Development Advisory Group's (MDAG's) paper on *Price discovery in a renewables-based electricity system*. That work identifies the risk of increased market concentration in dispatchable renewable generation - particularly hydro generation

[2] See MBIE. (2023, April). *Strengthening national direction on renewable electricity generation and electricity transmission*. Available at: https://www.mbie.govt.nz/dmsdocument/26387-strengthening-national-direction-on-renewable-energy-generation-and-electricity-transmission-consulation-doc-pdf

with long term storage - during the transition. This could result in weaker competition, higher prices and/or lower reliability. The Authority and MDAG considered a range of measures to monitor competition, reduce the likelihood and extent of any lessening of competition, and mitigate potential harms if competition is significantly weakened. We consider which measures could be considered back-stop measures. We also seek feedback on whether the government should further consider wider measures to address concerns raised by independent retailers, such as vertical separation, reducing the footprint of larger vertically integrated generator-retailers (‘gentailers’), and/or considering how to ensure independent retailers have access to flexible hedge contracts on terms equivalent to a gentailer’s retail arm. We seek feedback on whether government should consider specific measures in more detail.

Part 3, **Networks for the Future**, considers how we ensure sufficient transmission and distribution investment to support new renewable electricity and electrification. It seeks feedback on whether regulatory settings are sufficiently agile in a world where significant new investment and new network connections are required to support electricity system transition. In this Part, we note the Authority’s and Commerce Commission’s significant regulatory workstreams and seek feedback on areas for further government focus to support a secure, reliable energy transition and deliver affordability for consumers. Within Part 3:

- Chapter 7 **A Transmission system for growth** is about ensuring sufficient transmission investment for renewable electricity and electrification. It seeks feedback on how to ensure regulatory systems are fit for purpose to enable necessary transmission investments, as well as whether any further actions or steps are needed to support a resilient national grid.
- Chapter 8 **Distribution networks for growth** focuses on ensuring sufficient distribution system investment and reducing distribution system barriers to support electrification. It seeks feedback on whether any additional measures are needed to address challenges relating to connection of new demand, such as industrial load or EV chargers. It also seeks feedback on whether alternative approaches should be considered in relation to how costs are allocated to support network investment ahead of immediate need, as well as whether distribution pricing signals are sufficient to support efficient use of networks.
- Chapter 9 **Is the government’s sustainability objective adequately reflected for market regulators** seeks feedback on whether the government’s policy objectives are adequately reflected for our electricity system regulators. It also asks whether any additional direction would help to align the regulators’ own decision-making frameworks with government’s policy objectives such as issuing a Government Policy Statement.

Part 4, **Responsive Demand and Smarter Systems**, considers issues relating to increasing distributed flexibility. Within Part 4:

- Chapter 10 **Increasing distributed flexibility** looks at how the increasing uptake of distributed energy resources near homes and businesses is changing our electricity system. New technologies, including smart devices, are more readily available and the costs of storage are falling. This provides opportunities to use the benefits from distributed flexibility to improve electricity system reliability, resilience, security of supply and affordability. This chapter seeks feedback on whether there are areas where government action could further support development of markets for flexibility, address barriers to uptake and risks, and enable consumers to make choices about investing in these technologies. Possible measures include funding to support procurement of innovative services, measures to encourage retail tariffs that reward consumer flexibility and a regulatory review of critical data.

Part 5, **Whole of System Considerations** asks for views on how to prioritise across possible measures that could address the challenges outlined in this document. Within Part 5:

- Chapter 11 **Setting priorities and improving co-ordination** explores whether there is a case for greater formal co-ordination of planning of the electricity system as a whole. There are trade-offs between maintaining security and reliability, and equity and affordability, as we transition. This chapter considers challenges on how best to achieve balance across the - at times competing – objectives for the electricity system. It seeks feedback on priorities for government action, whether a new coordination function across the electricity system could play a useful role, and how to balance across the security and reliability, and equity and affordability objectives.

This *Measures for Transition to an Expanded and Highly Renewable Electricity System* issues paper considers a wide range of challenges ahead as the electricity sector transitions. Your feedback on this paper will help inform the Government's response to managing the electricity sector's transition.

# 1 Introduction

1. Transitioning to an expanded and more highly renewable electricity system brings opportunities for Aotearoa New Zealand. The transition will drive innovation and create new solutions to transport power to our homes and businesses, and change the ways in which we use electricity to power industry, travel, heat our homes, cook and wash.

2. The Government has set several targets relating to emissions reduction and energy:

    - a target for net zero emissions of long-lived greenhouse gases by 2050 and three emissions budgets
    - a target for 50 per cent of total final energy consumption to come from renewable sources by 2035
    - an aspirational target for 100 per cent renewable electricity by 2030.

3. As we transition to meet these targets and support our growing economy, the government's aim is to balance the energy trilemma - energy security, affordability and sustainability. We will need to carefully consider these three core elements to transition to a renewable future. Meeting these targets will also require a united effort across the energy sector, government, industry, consumers and communities.

4. This paper relates to an action in the Government's first Emissions Reduction Plan (ERP) and looks at how we can ensure electricity is affordable, reliable and resilient while we transition. In this document, we use the term 'measures' to refer to any government support for transition. Measures could include providing information, facilitating or supporting collaboration and innovation, issuing new guidance or new or updated standards, financial support mechanisms, or changes to regulations or legislation.

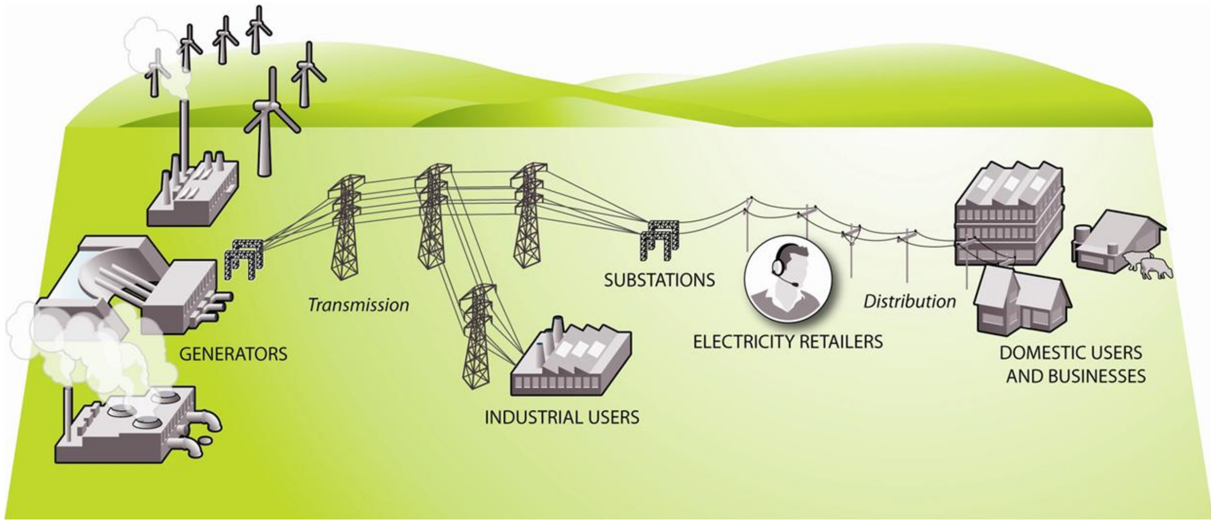
5. The paper aims to identify gaps where further measures could be needed. We review sector transitions already underway, as well as measures to support the transition that are being developed or considered, and then identify gaps where further or alternative measures could be considered or developed. We also include information on measures being considered or in use outside of New Zealand.

### THE NEW ZEALAND ELECTRICITY SYSTEM

6. The electricity industry in New Zealand has four main components – generation, transmission, distribution and retail (Figure 1).

7. Total installed generation capacity in New Zealand at the end of 2022 (including co-generation) was 10,100 MW. This is dominated by hydro-electric generation with over 5,000 MW of installed hydro capacity. More than 200 generation plants can supply electricity to the national grid, with the majority located in the South Island. Some of the smaller-scale generation is 'embedded' and feeds directly into local distribution networks. Most of New Zealand's electricity is generated in remote locations and transported via the transmission system to the main centres.

*Figure 1: The New Zealand electricity system*




8. State-owned enterprise Transpower owns and operates New Zealand's national electricity transmission system. The system includes substations, high voltage cables, transformers and overhead lines for transmitting high voltage electricity from power stations to distribution (lines) companies. Lines companies connect to the national grid and distribute the electricity to consumers through their local networks. Twenty-nine local lines companies ('distribution networks') distribute electricity throughout New Zealand.

9. Electricity retailers are the companies that sell electricity to smaller businesses and households. Retailers buy electricity from generation companies and bill customers for the energy they consume. Their bills to customers also include the cost of transmission and local distribution. In New Zealand there is a high degree of vertical integration between electricity generation and retail. The four main retail companies are also the main generating companies, known as vertically integrated 'gentailers'. As of April 2023, the combined market share of the four main retail companies was 84 per cent, with independent retailers making up the other 16 per cent.[3]

## *Our electricity system is changing*

10. Renewable electricity will play a key role in energy system transition. Reducing our reliance on fossil fuels and moving towards greater levels of renewable energy and other low-emissions alternatives will increase demand for electricity over the coming decades. Our electricity system will need to support consumer switching to electricity and to manage consumer energy costs.

11. MBIE's analysis projects that electricity demand could grow by 18 to 78 per cent between 2018 and 2050 across five different scenarios assuming different levels of economic growth, technological progress and policy changes.[4] Transpower estimates that a 68 per cent increase

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[3] Electricity Authority. (2023, April). *Market share snapshot*. Electricity Market Information website. Available at: https://www.emi.ea.govt.nz/Retail/Reports/R_MSS_C

[4] MBIE. (2019, July). *Electricity demand and generation scenarios: Scenario and results summary* (MBIE, 2019). Available at: https://www.mbie.govt.nz/dmsdocument/5977-electricity-demand-and-generation-scenarios-report-2019-pdf

in electricity generation is needed to meet demand by 2050, from 43 TWh in 2020 to 70 TWh.[5] This is made up of a 14 per cent increase in base electricity demand, a 38 per cent increase in electricity demand from vehicle electrification and a 16 per cent increase in demand from electrification of process heat and industry.

12. Our electricity system is already changing. Significant investment in new renewable electricity generation has been consented and is in the pipeline. There is about 2,600 GWh/year of new renewable electricity generation expected to be online between now and 2026.[6] In the last quarter of 2022, renewable energy sources provided nearly 95 per cent of all electricity generated.[7]

13. Industrial users are looking at electrification as an option to help decarbonise their operations. In the first four rounds of GIDI funding, 34 electricity projects were awarded a total of $36.3 million in government co-funding, equating to an expected 3.1Mt $CO_2$e in emissions reductions across the life of the projects. Other work on electrification is underway, including investigating the potential for electrification of process heat demand.[8]

14. Around 1,500 electric vehicles (EVs) are being added to the light vehicle fleet each month, making up around one in five new vehicle sales.[9] Transpower estimates that electrification of light and heavy land transport is expected to ramp-up in the late 2020s and early 2030s, requiring an additional 5 TWh of electricity by 2035 and 16 TWh by 2050.[10]

15. Government is supporting the electrification of the transport fleet through initiatives such as the Clean Car Discount and through funding in Budget 2023 for up to 23 charging hubs with multiple fast chargers and up to 1,000 charging units to support charging in rural and regional communities. Over $120 million over four years will go towards this infrastructure, the delivery of the electric vehicle charging strategy, and research to inform future investments. The Government also recently consulted on development of its EV charging strategy, *Charging our Future*.

16. Hydrogen projects could also add significantly to the demand for electricity. Modelling outlined in the government's *Interim Hydrogen Roadmap* (released alongside this issues paper) suggests hydrogen production could at least double the amount of additional generation already forecast to be required by 2050, adding another 12.5-23.4 GW of

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5 Transpower. (2020, March). *Whakamana i Te Mauri Hiko: Empowering our Energy Future*. Available at: https://tpow-corp-production.s3.ap-southeast 2.amazonaws.com/public/publications/resources/TP%20Whakamana%20i%20Te%20Mauri%20Hiko.pdf?VersionId=FljQmfxCk6MZ9mIvpNws63xFEBXwhX7f

6 Electricity Authority. (2023, 14 February). *New Zealand's electricity future: generation and future prices*. Electricity Authority website. Available at: https://www.ea.govt.nz/news/eye-on-electricity/new-zealands-electricity-future-generation-and-future-prices/

7 MBIE. (2023, 9 March). *New record renewable share of electricity generation in New Zealand*. MBIE website. Available at: https://www.mbie.govt.nz/about/news/new-record-renewable-share-of-electricity-generation-in-new-zealand/

8 For example, the South Island Study being conducted by EECA, Transpower and electricity distribution businesses – see DETA Consulting. (2022). *Process Heat Fuel Future, Part 1: South Island*. Available at: https://carbon.deta.global/nz-process-heat-pt1

9 Transpower. (2022, September). *Whakamana i Te Mauri Hiko: Monitoring Report*. Available at: https://tpow-corp-production.s3.ap-southeast-2.amazonaws.com/public/2022-11/WiTMH%20Monitoring%20Report%20-%20Sept%2022.pdf?VersionId=KsZ9cm5WRYZMjtGY9DsBIe6JVmYL781J

10 Transpower. (2020, March). *Whakamana i Te Mauri Hiko: Empowering our Energy Future*.

generation capacity, depending on the scale of hydrogen production, and whether there is production for export of hydrogen, green chemicals and products like steel.

17. Network infrastructure will need to grow to support increasing electricity supply and use. Transpower's Net Zero Grid Pathways Project is a multi-year programme of work to investigate and develop the transmission projects needed for expansion of our electricity system. Electricity lines companies are also focussed on actions to enable the electrification of New Zealand's energy needs.[11]

### *New Zealand's electricity market performs well against international comparators*

18. The World Energy Council's annual assessment, which produces the 'Trilemma Index' (referring to the energy trilemma described in paragraph 3) considers energy security, equity (which includes access and affordability) and environmental sustainability. The latest World Energy Council annual assessment (2022) ranks New Zealand at 8th and notes the current level of renewable electricity generation is 82 per cent.[12] New Zealand has consistently remained within the top 10 countries since 2012.

19. The World Energy Council also notes that over the last decade, New Zealand's energy sustainability score has improved as fossil fuel generators retire and are replaced by geothermal and wind, but the security score has declined by a small amount in recent years as New Zealand has become increasingly reliant on coal and fuel imports. New Zealand's equity score has remained consistently high over the past twenty years.

20. However, while our electricity system is doing well, we will still face challenges in the transition. Many other countries are not yet facing the challenges of a highly renewable electricity system – as they rely to a greater degree on fossil fuels or nuclear power, are less weather-dependent and have greater interconnections with other countries' generation to balance demand and supply.

## GOVERNMENT'S VISION FOR THE ENERGY SYSTEM

21. This ERP action on electricity system transition is one of the core pillars contributing to the current development of the New Zealand Energy Strategy due to be finalised in 2024. Building from the first ERP, the Energy Strategy will set out a vision and potential pathways to address strategic challenges in the energy sector as we transition towards net zero long-lived gases in 2050.

22. The Government's objectives for the Energy Strategy are:

- Energy affordability and energy equity for consumers.
- Ensuring that our energy supply is secure and reliable, including as we adapt to the effects of climate change and in the face of global shocks.

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[11] See Electricity Networks Association. (2023). Electrification of NZ's energy needs. *ENA Resources*. Available at: https://www.ena.org.nz/resources/electrification-of-nzs-energy-needs/

[12] World Energy Council. (2022). *World Energy Trilemma Index*. Available at: https://trilemma.worldenergy.org/ and https://bec.org.nz/wp-content/uploads/2022/11/trilemmaindex2022-final.pdf

- Our energy system transitions at the pace and scale required to support a net zero 2050.
- Our energy system supports economic development and productivity growth aligned with the transition.

23. This paper aligns with the above four objectives in the Energy Strategy and focuses on a subset of these: how to ensure the right measures are in place to achieve the sustainability goal of a renewable electricity system, whilst ensuring a secure, reliable and affordable supply.

24. The terms, as used in this paper and relating to the objectives for our electricity system, are the World Energy Council's trilemma definitions (emphasis added):[13]

- **Energy security** measures a nation's capacity to meet current and future energy demand reliably, and withstand and bounce back swiftly from system shocks with minimal disruption to supplies. This dimension covers the effectiveness of management of domestic and external energy sources, as well as the **reliability** and **resilience** of energy infrastructure.
- **Energy equity** assesses a country's ability to provide universal access to reliable, **affordable**, and abundant energy for domestic and commercial use. This dimension captures basic access to electricity and clean cooking fuels and technologies, access to prosperity-enabling levels of energy consumption, and affordability of electricity, gas, and fuel.
- **Environmental sustainability** of energy systems represents the transition of a country's energy system towards mitigating and avoiding potential environmental harm and climate change impacts. This dimension focuses on **productivity and efficiency** of generation, transmission and distribution, decarbonisation, and air quality.

25. These objectives are further considered within this discussion document. Chapter 9 considers whether the statutory objectives for the Authority and the Commerce Commission (Commission) are closely enough aligned with the government's sustainability policy objective. Chapter 11 considers, separately, the challenge of balancing the government's policy objectives, across sustainability, reliability and affordability.

## CHALLENGES AS WE TRANSITION, AND A GAP ANALYSIS: WHICH MEASURES SHOULD BE DEVELOPED TO SUPPORT THE TRANSITION?

26. This issues paper assumes as an endpoint that our electricity system will either be 100 per cent renewable or that significant progress will have been made towards a more highly renewable electricity system.

27. As we aim for a reliable and affordable transition, the challenges we need to consider for the electricity sector span generation, transmission, distribution and how end customers use

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[13] World Energy Council. (2023, June). *World Energy Trilemma Index*. Transition Toolkit, World Energy Council website. Available at: https://www.worldenergy.org/transition-toolkit/world-energy-trilemma-index

electricity. This issues paper seeks your feedback on these challenges. We ask for views on which are the most pressing to address.

28. This paper includes information on measures currently being considered by other agencies within New Zealand, and measures that are in place or in development, to address similar challenges, in countries outside of New Zealand. This information is included to illustrate what could be done, and to seek feedback on what measures should be considered in more detail by government and with further consultation with stakeholders.

29. This paper does not propose what measures should be implemented. Its primary purpose is to understand whether there are any gaps where further or alternative measures may need to be considered, and then potentially developed, to support a successful electricity system transition. Further consultation would take place on the design, effectiveness and impacts of any new proposed measures.

30. Challenges we need to consider include:

- **Ensuring that fossil fuel use in the electricity system reduces** at a rate consistent with our aims. The price signal sent by the New Zealand Emissions Trading Scheme (ETS) helps incentivise investment in new renewable electricity generation and reduction in the use of fossil fuels. However, the price signal sent by the ETS may reduce electricity system emissions at an uncertain rate. As existing fossil fuel-based generation retires, and when the electricity system faces long periods of low sun, low wind, or low lake levels, sufficient generation must be available to meet electricity demand. There will be a need to address the:

  **'Peaking challenge'.** Adequate dispatchable capacity, storage, or demand-side response needs to be available to meet demand in the short and long term (multi-hour and multi-day firming). We expect slow-start fossil fuel generation to contribute less to this role over time, as they cannot respond to a rapid need for firming if they are not already operating or warm from recent operation.

  **'Dry year challenge'.** The NZ Battery Project is tasked with identifying a long-term solution to 'dry year' risk: storage available to generate when lakes are low over multiple weeks. This dry year risk could be exacerbated during the next 10-15 years if we lose or reduce the existing options to manage it.

- **Ensuring competitive markets (both wholesale and retail).** Both the Market Development Advisory Group (MDAG) and the Authority have noted that transition may lead toward more concentrated ownership of dispatchable fuel options (particularly hydro storage) if fossil plants retire and there has not been sufficient investment in peaking and firming resources. A competitive retail market, where independent retailers can access wholesale supply in an equivalent way to a vertically integrated gentailer, will provide innovative products, service and pricing and help to support retail affordability and equity.

- **Growing and enhancing the transmission network.** This needs to progress at a sufficient pace to meet demand growth and ensure reliability and equitable cost allocation across customers.

- **Growing and enhancing our local lines systems (the distribution networks).** This also needs to progress at a sufficient pace to meet electrification needs, support more localised generation and ensure connection and network costs are allocated fairly.
- **Removing barriers to new larger scale demand connections.** There will be a need for new industrial load connections for the electrification of process heat and manufacturing, and new public EV charging points to support the electrification of transport. We will need to incentivise distributed flexibility resources and support opportunities to provide demand response to help manage the system's balance of supply and demand.
- **Supporting smarter use of networks and smarter technologies.** Supporting the uptake of electricity efficient technologies, smart technologies, distributed flexibility, distributed energy generation resources and smaller scale storage will help to minimise transition costs.

## OTHER POLICY INITIATIVES CURRENTLY UNDERWAY TO FUTURE PROOF OUR ELECTRICITY SYSTEM

31. This issues paper is published as part of a package of papers responding to actions outlined in the ERP. These all contribute to the development of New Zealand Energy Strategy and include:

    - the design and implementation of the **ban of new fossil fuel baseload electricity generation**
    - the **Gas Transition Plan Issues Paper**, which seeks feedback on the strategic direction for the gas sector
    - regulatory settings for **Offshore Renewable Energy**, to provide certainty to investors and to manage development of the industry
    - an **Interim Hydrogen Roadmap** to provide direction on the role hydrogen may play in our energy transition, actions the government is taking to support this, and areas signalled for further consideration alongside the New Zealand Energy Strategy.

## FURTHER INITIATIVES UNDERWAY AND APPROACHES IN DEVELOPMENT, TOWARDS SUPPORTING THE TRANSITION

32. A range of work across government agencies is underway to examine issues for transition to a more highly renewable electricity system such as:

    - The Commission is reviewing the input methodologies that set rules and processes for regulation under Part 4 of the *Commerce Act 1986*, including for transmission and distribution lines under its 2023 Input Methodologies Review (the IM Review), and on 14 June 2023 released a draft report, draft topic papers, and draft IM amendments determinations.[14]

- The Authority concluded its review of competition in the wholesale electricity market, and released its findings and decisions in May 2023.[15]
- The Authority's Future Security and Resilience Project is, in conjunction with the System Operator, undertaking a multi-year programme of studies to address challenges and opportunities affecting security and resilience of the power system as it transitions towards integrating more renewable, intermittent energy sources.[16] As part of this project, the Authority recently consulted on its investigation into the risks associated with the premature retirement of fossil fuel generation plants and high level options to mitigate these risks.
- The Authority recently consulted on updating regulatory settings for distribution networks to improve competition and innovation on networks to support a low emissions economy and expects to propose and consult on priorities for this work programme later in 2023.[17]
- The GIDI Fund is funding projects for decarbonisation of industry.[18]
- Following consultation, the Government's EV charging strategy, *Charging our Future*, is being finalised.[19]
- The Government has decided to amend the *Energy Efficiency and Conservation Act 2000* to allow regulations to be made requiring devices like EV chargers to have "smart" capabilities.
- The Climate Change Commission recently consulted on draft advice on the second ERP.[20] The second ERP is due to be set by the end of 2024.
- MBIE and the Ministry for the Environment recently consulted on strengthening national direction (under the *Resource Management Act 1991*) on renewable electricity generation and electricity transmission. To achieve a more enabling consenting regime, this work proposes amendments to the *National Policy*

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14 Commerce Commission. (2023, 14 June). *2023 Input Methodologies Review*. Commerce Commission website. Available at: https://comcom.govt.nz/regulated-industries/input-methodologies/input-methodologies-for-electricity-gas-and-airports/input-methodologies-projects/2023-input-methodologies-review

15 Electricity Authority. (2023, May). *Review of wholesale market competition.* Electricity Authority website. Available at: https://www.ea.govt.nz/projects/all/review-of-wholesale-market-competition/

16 Electricity Authority. (2023, June). *Future security and resilience.* Electricity Authority website. Available at: https://www.ea.govt.nz/projects/all/future-security-and-resilience/

17 Electricity Authority. (2023, June). *Updating regulatory settings for distribution networks*. Electricity Authority website. Available at: https://www.ea.govt.nz/projects/all/updating-regulatory-settings-for-distribution-networks/

18 EECA. (2023, June). *About the Government Investment in Decarbonising Industry Fund.* EECA website. Available at: https://www.eeca.govt.nz/co-funding/industry-decarbonisation/about-the-government-investment-in-decarbonising-industry-fund/

19 Ministry of Transport. (2023, March). *Charging Our Future: a draft long-term electricity vehicle charging strategy for Aotearoa New Zealand*. Available at: https://consult.transport.govt.nz/policy/charging-our-future/

20 Climate Change Commission. (2023, April). *2023 Draft advice to inform the strategic direction of the Government's second emissions reduction plan*. Available at: https://www.climatecommission.govt.nz/our-work/advice-to-government-topic/advice-for-preparation-of-emissions-reduction-plans/2023-draft-advice-to-inform-the-strategic-direction-of-the-governments-second-emissions-reduction-plan-april-2023/

*Statement for Renewable Electricity Generation* (NPS-REG) and *National Policy Statement for Electricity Transmission* (NPS-ET).[21]

33. The above list is not exhaustive and there are a number of work programmes underway across the electricity system. Additional information on some of these programmes is included in this paper at the time of writing (August 2023). However, we note there are a range of decisions expected in the coming months.

34. Additionally, we note this paper focuses on transition issues, and other ERP-related actions separately address issues relating to a 100 per cent renewable electricity system, such as MDAG's project on price discovery in a renewables-based electricity system and MBIE's NZ Battery Project exploring the challenge of dry year storage. Also out of scope are questions on the role of the electricity industry in economic development. Issues relating to economic development, labour market and skill needs, and ensuring a just transition, will be addressed through the Energy Strategy, the development of an Equitable Transitions Strategy and the work of MBIE's Just Transitions Unit.[22]

## NEW ZEALAND'S 'ENERGY ONLY' ELECTRICITY MARKET AND THE EMISSIONS TRADING SCHEME

### *The 'energy only' market*

35. New Zealand operates an 'energy-only' wholesale market, which means each supplier is paid for the energy it generates, in a given time period, at the market clearing wholesale spot price. This price reflects the most expensive generation offer that is needed to meet demand in that time period. Energy purchasers – the large industrials and retailers – pay for power at the same spot price. Wholesale suppliers and purchasers choose their level of contracting (or 'hedging') to reduce their exposure to changes in spot prices: if a fixed price hedge has been agreed, the buyer essentially pays that fixed price, no matter what is happening in the spot market.

36. This 'energy only' wholesale market, together with the price signal set by the ETS, should help to incentivise investment in new renewable generation and lead to the retirement of fossil fuel generation. Higher prices when fossil fuel plants are generating (due to the carbon cost), should incentivise investors to develop and deploy technologies that can generate at a lower cost than when the marginal plant setting the spot price is a fossil fuel plant.

### *The New Zealand Emissions Trading Scheme*

37. The New Zealand Emissions Trading Scheme or ETS is a key tool for meeting our domestic and international climate change targets. The ETS helps reduce emissions by doing three main things:

- requiring businesses to measure and report on their greenhouse gas emissions

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21 MBIE. (2023, June). *Consenting improvements for renewable electricity generation and transmission.* MBIE website. Available at: https://www.mbie.govt.nz/have-your-say/renewable-electricity/

22 MBIE. (2023, June). *Just Transition.* MBIE website. Available at: https://www.mbie.govt.nz/business-and-employment/economic-development/just-transition/

- requiring businesses to surrender one 'emissions unit' (known as an 'NZU') to the government for each one tonne of emissions they emit
- limiting the number of NZUs available to emitters (ie, that are supplied into the scheme).

38. Electricity generators are fully exposed to the ETS. The ETS makes it more expensive to use fossil fuels in electricity generation. This provides an incentive to use less electricity, choose low emissions alternatives, invest in renewable generation, and to innovate and find new technologies to replace fossil-fuel generation. The NZU spot price has increased by more than 150 per cent in the past two years, from around $35 to over $88 in September 2022. The NZU spot price on the secondary market is trading around $60 as of 1 August 2023.

39. The ETS can be expected to drive some of the changes necessary to transition, however cannot be expected, by itself, to create all the necessary conditions to support the transition. The ETS will need to work together with wider measures such as information, coordination and support levers to reduce emissions in line with our emissions budgets and targets, driving greater change than a single measure could do on its own. As noted by Climate Change Commissioner Catherine Leining *"Additional policies are needed to secure equitable outcomes, overcome barriers to change that are not about price and co-ordinate research and investment at the frontier of innovation."*[23]

40. The approach of relying on the ETS as well as other policy measures is consistent with the Intergovernmental Panel on Climate Change (IPCC)'s 2022 *Mitigation of Climate Change* report, which includes detailed advice on how governments can design the optimal policy packages to drive climate and development policies. This report notes:[24]

> Policy integration, addressing multiple objectives, is an essential component of shifting development pathways and accelerating mitigation.
>
> Both theoretical and empirical analysis reinforce the argument that single policy instruments are not sufficient (robust evidence, high agreement). Policymakers might rather mobilise a range of policies, such as financial instruments (taxes, subsidies, grants, loans), regulatory instruments (standards, laws, performance targets) and processual instruments (demonstration projects, network management, public debates, consultations, foresight exercises, roadmaps).
>
> The appropriate mix is likely to vary between countries and domains, depending on political cultures and stakeholder configurations (Rogge and Reichardt 2016), but is likely to include a combination of: (i) standards, nudges and information to encourage low-carbon technology adoption and behavioural change; (ii) economic incentives to reward low-carbon investments; (iii) supply-side policy instruments including for fossil fuel production (to complement demand-side climate policies); and (iv) innovation support and strategic investment to encourage systemic change (Grubb 2014). These approaches can be mutually reinforcing. For example, carbon pricing can incentivise low-carbon innovation, while targeted support for emerging niche technologies can make them more competitive, encourage their diffusion and ultimately facilitate a higher level of carbon pricing. Similarly, the success of feed-in tariffs in Germany only worked as well as it did because it formed part of a broader policy mix including 'supply-push' mechanisms such as subsidies for research and

23 Climate Change Commission. (2023, June). *Insight: Why the ETS alone won't get us to net zero emissions.* Climate Change Commission website. Available at: www.climatecommission.govt.nz/news/insight-ets/

24 Intergovernmental Panel on Climate Change. (2022) *Climate Change 2022: Mitigation of Climate Change*. Chapter 4, section 4.4.1.2. Available at: https://www.ipcc.ch/report/ar6/wg3/downloads/report/IPCC_AR6_WGIII_FullReport.pdf

'systemic measures' such as collaborative research projects and systems of knowledge exchange (Rogge et al. 2015).

41. This paper takes this approach by considering the full suite of challenges ahead as the electricity sector transitions. In a range of areas – across generation, transmission, distribution, and how and when consumers use electricity – we invite you to provide feedback on whether additional measures may be needed, and the areas government should prioritise to support the transition to an expanded and more highly renewable electricity system.

## COMMONLY USED ELECTRICITY MARKET CONCEPTS

42. Some concepts that are used commonly in electricity markets and in this document are explained below. These and other common technical terms relating to the electricity system are also included in a glossary at the end of this document

- **Baseload generation** is supplied by generators designed to be operated near/or at full capacity most of the time or to provide 'seasonal energy' during winter when demand is high and hydro generation is typically low. In New Zealand the term 'baseload' has tended to be used firstly for those generators that run continuously, except for maintenance, up to the maximum capacity allowed by their water, steam or fuel supply. A companion paper *Implementing a ban on new fossil-fuel baseload electricity generation* discusses the design and implementation of a ban on new fossil fuel baseload generation in New Zealand.
- **Peaking generation** refers to generation that usually operates only for minutes or hours each day, during the sharpest demand peaks. It can also respond quickly to reductions in intermittent renewable generation. Currently most peaking generation is supplied by hydro generation and by Open Cycle Gas Turbines (OCGT). It is not normal for slow start fossil fuel generation to operate in a peaking role unless already warm because it can take many hours to start when cold.
- **Intermittent generation** refers to generation that is subject to variable or unpredictable fuel input, usually due to weather and can only run some of the time, for example solar (when the sun is shining) and wind (when it's windy).

43. **Dispatchable and firming generation are additional terms used to describe different** roles that can be performed by generation and by demand response. Dispatchable or firming generation is a resource (such as the Huntly Power Station's 'Rankine units', combined cycle gas turbines (CCGTs) and fast-start gas peaking plant)[25] that is reliably available when called on or 'dispatched', as compared to intermittent which is not always available. Firming/dispatchable resources also include storable hydro generation, batteries and demand response. These last two are expected to play a greater role in providing firming capacity over time and are discussed further in later chapters.

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[25] There are three operational 'Rankine units' at Huntly Power Station. Their steam turbines are fired by coal or fossil gas, and potentially by other fuels. New Zealand currently has two operational gas fired CCGTs located at Stratford and Huntly. They are more energy efficient than OCGTs but take longer to start up when cold. New Zealand currently has a number of such plant operating in half a dozen or so locations.

# PART 1: GROWING RENEWABLE GENERATION

Part 1, **Growing Renewable Generation**, is about ensuring sufficient renewable generation is built to electrify the economy and about how we replace the roles currently played by fossil fuel generation in a way that maintains security, reliability and affordability. Within Part 1:

Chapter 2 **Accelerating supply of renewables** is about how to enable the investment in new renewable generation needed for electrification. The chapter seeks feedback on whether current approaches for new generation build are sufficient or whether further measures may be needed to support development of new renewables during transition. The chapter outlines examples of measures considered overseas to de-risk investment, such as power purchase agreements or contracts for differences. It notes that the scope of need for such measures is unclear, and it would be important to ensure that any further measures result in investment in addition to what would be built anyway.

Chapter 3 **Ensuring sufficient firm capacity during transition** discusses the crucial roles currently played by fossil fuels. As fossil fuel plants retire, and the electricity system faces periods of high demand or low sun, wind or lake levels, there is a need to ensure we have sufficient generation to call on to meet peak demands and to 'firm' intermittent renewables. This chapter considers the need for 'firm' capacity that can support expansion of our electricity system during transition, whether fossil gas-fired (if needed in transition), or through alternatives such as battery storage. It outlines work underway in New Zealand and overseas on this issue. It asks whether New Zealand may need additional measures to ensure sufficient peaking and firming capacity until technologically feasible renewable solutions are available.

Chapter 4 **Managing slow start fossil fuel capacity during the transition** focuses on ensuring an orderly exit from current fossil fuel electricity generation. It outlines work underway by the Electricity Authority (Authority) to mitigate any security of supply risk if a fossil fuel plant retires in a sudden or disorderly way. The chapter seeks feedback on whether any further measures should be considered to support managed phase down of existing fossil fuel electricity generation for security of supply during transition.

Chapter 5 **The role of large-scale flexibility** asks whether we have the right settings in place to incentivise the provision of efficient large-scale flexibility as a form of firming from industrial users and the maintenance of existing ripple control by distributors. It seeks feedback on what mechanisms could be further considered to incentivise demand response from industrial consumers, distributors, and retailers.

### *Focus for Part 1: Growing renewable generation*

| | |
|---|---|
| **CHALLENGES** | • Ensuring sufficient new renewable dispatchable generation to replace retiring fossil fuel generation<br>• Ensuring sufficient new renewable generation to meet increasing demand<br>• Ensuring sufficient firming capacity to support new renewables and ensure security and reliability<br>• Managing the pace of fossil fuel generation retirement |
| **WORK ALREADY UNDERWAY** | • Market Development Advisory Group's (MDAG's) work on price discovery in a renewables-based electricity system<br>• The Authority's recent papers – *Ensuring an Orderly Thermal Transition* and |

| | *Promoting competition in the wholesale electricity market in the transition toward a renewables-based electricity system* |
|---|---|
| **FURTHER POSSIBLE MEASURES TO CONSIDER** | • Support for new generation to run in peak demand periods, at short notice<br>• Support for new renewable generation (that runs most of the time)<br>• Support for existing or new fossil gas fired generation that can generate at short notice if needed in the short-term during transition<br>• Support to manage phasedown of existing fossil fuel generation for security of supply<br>• Support for development of new large-scale renewable generation<br>• Enhancing demand-side response as a viable generation alternative |

# 2 Accelerating supply of renewables

44. Electrification of industry and transport, and economic growth, will significantly increase the demand for electricity, and require significant new investment in renewable electricity generation and network infrastructure. Transpower has forecast a 68 per cent increase in electricity generation is needed to meet demand by 2050, from 43 TWh in 2020 to 70 TWh.[26] This is made up of a 14 per cent increase in base electricity demand, a 38 per cent increase in electricity demand from vehicle electrification and 16 per cent increase in demand from electrification of process heat and industry. Additionally, investment in new renewable generation will be needed to replace the roles currently played by fossil fuel generation, ensuring security of supply and affordability for consumers.

45. The Infrastructure Commission indicates that round 400 – 500 MW of new electricity generation capacity (or demand response) will be needed every year until 2050.[27] This is a significant increase compared to the rate at which new generation has been built in New Zealand in previous decades. A survey by Concept Consulting (Concept), as part of the Electricity Authority's (Authority's) November 2022 wholesale competition issues paper, identified gross new generation additions are likely to average around 780 GWh per year between 2021 and 2025.[28] This is around two and a half times the historical rate of development. Concept indicated that this investment is likely to be sufficient to meet electrification-related demand growth to 2025. Boston Consulting Group's (BCG's) 2022 *The Future is Electric* report also suggested that there is more than enough renewable energy generation in the project pipeline to achieve 98 per cent renewable generation by 2030. BCG identified 10.9 GW of new utility-scale renewables intended to be built against a need of 4.8 GW by 2030.[29]

46. However, there remains a risk that signalled investment may not come forward in sufficient time or quantity to enable electrification, while maintaining security and affordability.

### *Uncertainties could be hindering investment in new renewable generation*

47. Various reports including the Authority's analysis of wholesale market competition, the Market Development Advisory Group's (MDAG's) report on price discovery in a renewables-based electricity system and BCG's 2022 report on the electricity sector, highlight factors that may slow development of sufficient new renewable generation to meet projected demand. These factors include technology, regulation (government policy) and demand uncertainties; managing investment risks, including price risk; obtaining consents under the *Resource*

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26 Transpower. (2020, March). *Whakamana i Te Mauri Hiko: Empowering our Energy Future*.

27 New Zealand Infrastructure Commission Te Waihanga. (2022). *Technical paper: Leveraging our energy resources to reduce global emissions and increase our living standards*. Available at: https://www.tewaihanga.govt.nz/assets/Uploads/Leveraging-our-energy-resources.pdf

28 Electricity Authority and Concept Consulting. (2022, July). *Generation investment survey 2022*. Available at: https://www.ea.govt.nz/documents/2156/Information-paper-Generation-Investment-Survey-2022-Concept-Consulting-.pdf

29 Boston Consulting Group. (2022, October). *The Future is Electric - A Decarbonisation Roadmap for New Zealand's Electricity Sector*. Page 15. Available at: https://web-assets.bcg.com/b3/79/19665b7f40c8ba52d5b372cf7e6c/the-future-is-electric-full-report-october-2022.pdf

*Management Act 1991* (RMA); regulatory processes for offshore wind; meeting *Overseas Investment Act 2005* requirements and supply chain and skills availability issues.

48. This section focuses mainly on the first two of these issues. Government recently consulted on changes to the *National Policy Statement for Renewable Electricity Generation* (NPS-REG) to provide more enabling policy direction for renewable electricity generation.[30] The Overseas Investment Office recently updated its web-based guidance and enquiries functionality.[31] Issues concerning offshore wind (and other offshore renewable resources) are covered in the separate discussion paper *Developing a Regulatory Framework for Offshore Renewable Energy* released by MBIE alongside this issues paper.

### *Regulatory and market uncertainties*

49. Factors that may be creating regulatory and market uncertainties for investment include:

- future fossil gas supply and flexibility (including storage) to support dispatchable fossil gas-fired generation in a firming role
- whether or how the government will progress with Lake Onslow or other options currently under investigation in the NZ Battery Project
- direction and pace of broader policy development in the Energy Strategy, Emissions Reduction Plan, ETS and RMA reform
- future electricity demand, including from existing large consumers (particularly New Zealand Aluminium Smelter) and from potential new demand sources (such as data centres and green hydrogen production), industrial process heat electrification, and transport electrification.

50. Green hydrogen production could significantly influence the need for future investment over and above the electrification of transport and process heat. The future role of hydrogen in New Zealand is considered in the *Interim Hydrogen Roadmap* released by MBIE alongside this issues paper. The modelling supporting that paper estimates that hydrogen production could at least double the amount of additional generation already forecast to be required by 2050, adding another 12.5-23.4 GW of generation capacity. The size of this figure depends on the scale of hydrogen production, and whether there is production for export of hydrogen, green chemicals and products like steel. To illustrate the significance of these figures, our current national installed electricity generation capacity is 10 GW, and we anticipate needing an additional 10 GW or more by 2050 to meet the demand for electricity as we decarbonise transport and industrial process heat.

### *Price risk for investors in baseload renewables*

51. Wholesale spot market prices vary considerably, and intermittent renewable developers face volatile revenues if solely reliant on the spot market. The key risk is that spot prices will be low when they are generating and high when they are not generating. Developers typically

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30 MBIE. (2023, June). *Consenting improvements for renewable electricity generation and transmission.* MBIE website.

31 Land Information New Zealand. (2023, June). *Overseas investment factsheets.* Land Information New Zealand website. Available at: https://www.linz.govt.nz/guidance/overseas-investment/overseas-investment-factsheets

seek arrangements through which they secure fixed prices for at least some generation output to reduce the investment risk and the financing costs of generation projects.

52. However, electricity users are also typically averse to spot price risk and may be reluctant to buy generation from new intermittent renewables at a fixed price if they remain exposed to the spot price for their residual electricity needs. Users generally prefer to have arrangements for access to firm supply when they need it and have varying levels of comfort in managing price risk. New generation investors may therefore be challenged to find buyers for their output without suitable risk management products being available at a reasonable price.

53. As the volume of intermittent generation grows over time, spot prices are expected to become more volatile. Concerns over exposure to spot prices may grow and it will become more important to strengthen the market for risk management tools or products to help participants manage price risk effectively. This will assist retailers and consumers in managing their price risk which is important requirement to incentivise electrification.

54. While spot price volatility is an inherent feature of a highly renewable electricity system, MDAG highlights a risk that growing spot price volatility in a more highly renewable system could be perceived to be a problem rather than a natural and necessary signal for the market's efficient function. [32] MDAG recommended options to increase public confidence in the market (see Options E1 and E2 in its paper) to reduce the motivation for interventions that could suppress volatility, arguing this could affect participants' ability to manage risks and, in turn, whether enough investment comes online at the right time.

55. A recent paper by the International Renewable Energy Agency (IRENA)[33] takes a contrary view, suggesting that marginal cost pricing will struggle to procure both renewable generation and flexibility services in a highly renewable market, with the situation worsening as intermittent renewable electricity penetration increases. IRENA argues high volatility will not sustain renewable investment and calls for a system based more on long-term procurement methods, such as corporate or auctioned power purchase agreements (PPAs), feed-in tariffs (FITs), Contracts for Difference (CfDs) or other similar tools (which are discussed further below). According to IRENA, the political risk associated with high volatility could drive unavoidable calls for change.

## WHAT IS ALREADY UNDERWAY?

56. This chapter builds on the prior work of the Authority, MDAG, BCG and others in considering the role of incentives for renewables investment, and the role of firming capacity and fossil fuel-based generation during the transition. Inevitably, this approach will cover similar ground to that already explored in this prior work. The emphasis in this chapter is on whether additional measures may be needed to support new renewable generation to meet

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32 Market Development Advisory Group. (2022, December). *Price discovery in a renewables-based electricity system: options paper*. Paras 11.9-11.16. Available at: https://www.ea.govt.nz/documents/1006/MDAG_-_Price_discovery_in_a_renewables-based_electricity_system_-_options_paper.pdf

33 International Renewable Energy Agency. (2022, September). *Potential Limitations of Marginal Pricing for a Power System Based on Renewables, Technical paper 3/2022*. Available at: https://www.irena.org/Technical-Papers/Potential-Limitations-of-Marginal-Pricing-for-a-Power-System-Based-on-Renewables

government's emissions or climate targets. In some cases, because this chapter is looking at it from a different perspective, it may re-examine a question that prior work has considered closed.

57. The Authority, following its wholesale market review,[34] is taking a range of actions to facilitate investment in new renewable electricity generation and improve availability and access to tools to manage price risk including to:

- investigate and test the case for providing or requiring longer-dated futures (for instance products traded on the ASX)
- analyse fossil fuel generation transition risks in the context of demand to 2030, fossil fuels' role in hydro firming and more prevalent solar and wind generation, and options to mitigate transition risks.

58. MDAG's work on price discovery in a highly renewable electricity system also recommended measures to enable efficient investment and effective risk management. These recommendations, MDAG Options B1 to B7, include enhancements to improve information and price discovery.

59. For example, the provision of shaped hedge products could improve the ability of independent renewable investors to manage risk. However, ensuring sufficient liquidity and competition in this market will be key. The Authority and MDAG note a concern that as thermal generation retires during the transition, the market concentration of flexible hydro resources that underpin some of these contracts may increase. This is discussed further in Part 2.

## FURTHER MEASURES TO CONSIDER?

60. If existing market arrangements are not expected to deliver sufficient renewable generation at a scale to displace existing fossil fuel use, meet new demand growth as well as maintain affordability and security of supply during transition, then there are a range of mechanisms that could be considered to support investments.

61. Internationally a number of governments have implemented schemes to incentivise or bring forward new renewable generation. Generally, measures to support development of new renewable generation can be thought of as one of the following forms of support:

- CfD schemes
- FITs for large scale generation (FITs for end consumers are considered in Chapter 10)
- renewable certificate obligations
- PPAs.

62. Countries implementing such mechanisms include Australia, Western Europe and the United States, where there have been concerns that the traditional dynamics of an energy-only

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34 Electricity Authority. (2023, May). *Promoting competition in the wholesale electricity market in the transition toward a renewables-based electricity system: Decision paper*. Page 7. Available at: https://www.ea.govt.nz/documents/3017/Decision_paper_promoting_competition_through_the_transition.pdf

market do not provide sufficient incentives to invest in reliable capacity. They include 'capacity markets' that operate as part of an electricity market as well as mechanisms that add processes outside the market, often through direct government funding or regulation. Box 1 below provides some examples of mechanisms that have been adopted in different jurisdictions.

**Box 1: Examples of support for new renewable generation**

**Contracts for Difference**

A CfD is a financial contract based on the difference between a strike price and the wholesale energy price. It could be one-sided (ie, only activated when the wholesale energy price is on one side of the strike price) or two-sided. Traditionally a CfD is a financial contract in that it is not tied to the physical delivery of electricity. However, in practice CfDs used to support renewable generation are typically only triggered when the generator is generating and are based on actual output, and are sometimes referred to as physical CfDs.

A CfD helps remove the risk of price volatility. If the strike price is set above the expected energy price, then a CfD can provide more money to investors. The main upsides of a CfD are the following:

- It protects generators against price risk, because generators receive a guaranteed rate, or close to it depending on the precise design.
- It is usually implemented through an auction mechanism that is a well-understood concept among large-scale renewables developers, that can reveal the amount of additional money, if any, that investors need to develop a project.

A downside of a physical CfD is that if generators are not exposed to price risk at all, then the mechanism risks procuring the wrong kind of renewable technology. For example, by procuring too much generation that is cheaper per unit but less reliable in terms of output.

To solve this issue, a CfD design could ensure that generators receive a strike price consistent with the generation profile of that technology. This could be through a split CfD mechanism, eg like in Victoria (Australia), where different technologies have a different strike price.

| | |
|---|---|
| **United Kingdom** | • CfDs are the UK's main auction mechanism for supporting low-carbon electricity generation.<br>• Developers are paid a flat (indexed) rate for the electricity they produce over a 15-year period.<br>• Separate auctions for emerging technologies provide support for less established technologies to help foster their long-term potential. |
| **Germany** | • A one-sided CfD is available to offer protection against low prices (price floor), leaving the 'upside' from high wholesale market prices with generators.<br>• Generators have some exposure to market prices through having a small portion of their generation unhedged (around 5 per cent).<br>• CfDs are usually awarded through technology specific auctions, targeting a certain amount of capacity (in MW). |
| **Spain** | • In Spain two-sided CfD, based on the output generated, are available.<br>• CfDs are awarded through pay-as-bid auctions.<br>• Most auctions have been technology specific (wind, PV, concentrating solar power, biomass).<br>• Generators have some exposure to market prices through 5 per cent unhedged volume. |

<table>
<tr><td>Victoria (Australia)</td><td>The Victorian Government has implemented an auction scheme (Victorian Renewable Energy Target or VRET) that provides long-term CfD contracts to developers to build new renewable generation and storage projects. The scheme creates revenue stability for generators. Under the terms of the VRET CfD:<br><br>• Project developers receive the difference in the price when the wholesale price is lower than the strike price (although if the MWh price is below zero the state only pays the difference between the strike price and the $0/MWh floor price).<br>• A project proponent will owe the Victorian Treasury where the wholesale price is above the strike price.<br>• In addition, developers receive a fixed price payment, which is intended to reflect the guaranteed revenue required by proponents to support the project in addition to the certainty provided by the CfD.</td></tr>
<tr><td colspan="2">Feed-in Tariffs for generation</td></tr>
<tr><td colspan="2">Similar to a physical CfD, some jurisdictions globally have had a ‘feed-in tariff’ (FIT) regime that supports small-scale renewable generation that contributes generation to the grid. From a generator’s perspective, this is mechanically similar to a physical CfD, but there are two main differences:<br><br>• A single counterparty purchases the full volume of energy at the strike price. By contrast, in a CfD, the counterparty pays only the difference in price while the generator sells their power to wholesale market. The result is the same, but small generators are unable to participate in the wholesale market.<br>• The strike price for a FIT regime is determined administratively, rather than in an auction.<br><br>This type of mechanism is not usually used to attract large scale generation, so rather than being addressed in this chapter, discussion on this type of mechanism for development of small-scale generation is included in Chapter 10.</td></tr>
<tr><td>United Kingdom</td><td>• The UK provides a payment to accredited small-scale renewable generators for renewable generation.<br>• The cost of the scheme is allocated to energy retailers and passed on to consumers.</td></tr>
<tr><td colspan="2">Renewable Certificate Obligation</td></tr>
<tr><td colspan="2">A renewable certificate scheme produces a certificate for every MWh of energy generated from a certified renewable source. The generators can then sell these certificates to energy retailers or other energy purchasers which would allow them to meet an obligation (renewable electricity target) placed upon them by government.<br><br>This mechanism provides an additional revenue stream to renewable energy generators, based on the value of the certificates they produce. However, it leaves them exposed to market prices. Thus, this type of mechanism is appropriate if investors are more concerned with the expected level of revenue rather than the volatility of revenue.<br><br>The main upsides of a certificate scheme are:<br><br>• Generators are still fully exposed to price risk, meaning that the mechanism will attract the most profitable types of technologies which are most profitable in the wholesale market, and so which provide most value to the system.</td></tr>
</table>

<table>
<tr><td colspan="2"><ul><li>It is easier to administer than a CfD scheme because the Government does not need to ‘procure’ anything. Instead, it can set a target and a retailer obligation, and allows the market to determine how to best meet that.</li></ul>The main downsides of a certificate scheme are:<ul><li>As above, generators are still fully exposed to price risk and face significant risk to their revenues, especially over longer-term investment timeframes (eg, 20–25-years) where any significant value that may accrue over that time is difficult to forecast.</li><li>The value of the certificates themselves is dependent on market factors and government policy. So, generators are also exposed to price risk on the certificate price. For example, if the government changes its renewables targets within 10 years, this may impact affecting the value of renewables certificates.</li></ul></td></tr>
<tr><td>New Zealand</td><td><ul><li>Certified Energy operates a renewable energy certificate scheme which enables generators to sell certificates for each MWh of renewable energy generated.</li><li>Certificates are bought by businesses that value renewable electricity and/or wish to report their emissions against voluntary reduction targets.</li></ul></td></tr>
<tr><td>Australia</td><td><ul><li>Generators produce certificates for every MWh of renewable energy they produce (or displace).</li><li>Certificates are then sold and traded.</li></ul></td></tr>
<tr><td>United Kingdom</td><td><ul><li>Certificates are issued to accredited renewable generation for each MWh of renewable generation.</li><li>Renewable certificate obligations may be traded, but ultimately must be used by suppliers to demonstrate that they have met their obligation.</li></ul></td></tr>
<tr><th colspan="2">Power purchase agreements</th></tr>
<tr><td colspan="2">PPAs are commonly used by purchasers of energy to incentivise new renewable generation build, receive lower electricity prices, and gain long-term price certainty. PPAs are contracts between a generator and a buyer of the generator’s output that provides a fixed or contracted price for that output. This arrangement provides the generator with some certainty of revenue, but leaves the buyer exposed to price risk for the volume of their purchases not covered by the PPA contract.<br><br>Corporate and public sector PPAs have been used in many countries to achieve the organisations’ emission reduction and other sustainability objectives. Where (central or local) governments have been involved in PPAs this has generally been as an aggregated or consolidated buyer of a PPA, or in some cases to support the administrative arrangements to set the PPA mechanism up. For example, by providing online platforms and/or procurement services.</td></tr>
<tr><td>Victoria (Australia)</td><td><ul><li>A consortium of 51 local councils banded together to aggregate demand for a 100 per cent renewable PPA, known as the Victorian Energy Collaboration (VECO), which currently supports two new windfarms.</li></ul></td></tr>
</table>

## SOME CONSIDERATIONS WITH MARKET MECHANISMS FOR SUPPORTING NEW RENEWABLES

63. Mechanisms such as those outlined above could help to accelerate the build of new renewables by ‘de-risking’ investment in intermittent renewable projects. With greater certainty of price received from generation output, investors may be more willing to invest.

64. It will be important to carefully determine in what circumstances support is needed to ensure that investment is additional to what may otherwise have been built, as it would not be optimal if such mechanisms simply supported generation that otherwise would have been bought to market anyway.

65. There also is a need to carefully consider the role of incentives for investment in dispatchable generation or storage alongside incentives for investment in new intermittent renewables. If there is not sufficient investment in dispatchable generation or storage to support more intermittent generation during periods where it cannot generate (for example, calm, cloudy periods), this may create additional price volatility, and exacerbate the ‘peaking’ and ‘dry year’ challenges noted in the introduction to this issues paper.

66. Additionally, when considering international approaches, we should keep in mind New Zealand specific factors including:

- New Zealand’s already high level of renewable electricity generation compared to many other countries. Their electricity systems still rely to a greater degree on fossil fuels or nuclear power, are less weather-dependent and have greater interconnections with other countries’ generation for balancing demand and supply.
- New Zealand has an ETS that should incentivise investors to develop technologies that can generate at a lower cost than the when the marginal plant is a fossil fuel plant. That said, the EU also has an ETS, yet has still implemented certificate schemes to incentivise additional renewable build. Ideally, any scheme aiming to procure more renewable energy should be developed taking into account the effect that the ETS price will have on incentivising renewable investment.
- New Zealand has a liquid forward contracting market, but the range of available hedge products is narrower than in larger markets like Australia and the UK. Thus, the kinds of products needed for a renewable generator to lock in a price for its intermittent generation are currently less likely to be available for the time frame investors might require.
- Whether the introduction of a mechanism to support renewable generation has any bearing on any of New Zealand’s existing free trade agreements.

### *Questions*

| | |
|---|---|
| 1. | Are any extra measures needed to support new renewable generation during the transition?<br>Please keep in mind existing investment incentives through the energy-only market and the ETS, and also available risk management products. Any new measures should add to (and not undermine or distort) investment that could occur without the measures. |
| 2. | If you think extra measures are needed to support renewable generation, which ones should the government prioritise developing and where and when should they be used? What are the issues and risks that should be considered in relation to such measures? |
| 3. | If you don’t think further measures are needed now to support new renewable generation, are there any situations which might change your mind? When and why might this be? |

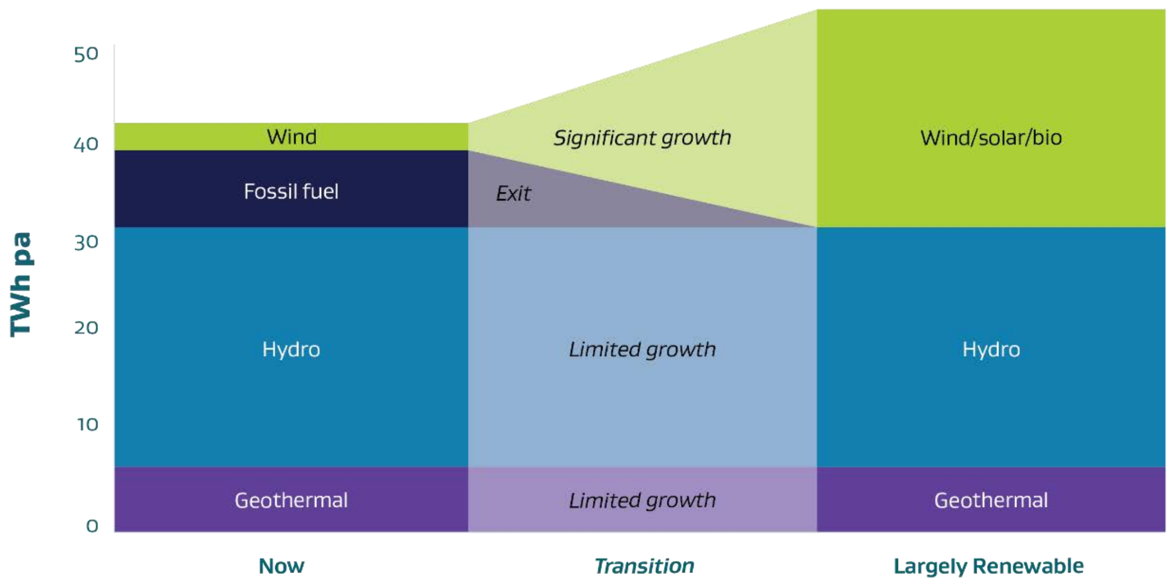
# 3 Ensuring sufficient firm capacity during transition

67. In addition to using electricity to decarbonise other sectors, to achieve our emissions budgets and energy targets we need to reduce our reliance on fossil fuels to generate electricity. The 'energy-only' market coupled with the price signal set by the ETS should help to drive this transition. The rate of change will depend on if and how ETS prices rise over time. As more renewable generation enters the market, and if ETS prices rise, fossil fuel generation is expected to reduce and eventually retire. However, the rate at which the ETS and renewable generation entry will reduce electricity system emissions is uncertain.

68. During the transition, we must ensure the reduction and eventual retirement of fossil fuel generation occurs in a way that maintains security and affordability of supply, while sustaining incentives for increased electrification.

69. Figure 2 illustrates the transition of fossil fuel generation from the electricity system. Fossil fuels currently provide around 20 per cent of New Zealand's electricity generation capacity, including significant stored energy (currently coal) which can be used to generate electricity over a potential dry year period of several months. The exit of fossil fuel generation will require replacement of this capacity, on top of meeting new demand growth.

*Figure 2: Transition of fossil-fuel generation from the electricity system*




70. As fossil fuels retire and the share of intermittent renewable generation increases, we must ensure adequate dispatchable capacity (resources reliably available when called on to generate) to meet demand in a system that is reliable and affordable.

71. Having sufficient dispatchable capacity during transition is important not only from a security of supply and affordability perspective, but also from a risk management and investment

perspective. If there is not enough dispatchable capacity available, this can lead to greater challenges for intermittent renewables investors to find buyers for their output.

## WHAT IS ALREADY UNDERWAY?

72. Recent modelling undertaken for Boston Consulting Group (BCG) and the Market Development Advisory Group (MDAG) indicates an ongoing role for some fast start peaking generation in the foreseeable future. This modelling indicates that fast start fossil gas-fired generation could potentially be replaced or supplemented by similar fast start generation using renewable fuels (such as renewable diesel) if or when such fuels become economic alternatives to fossil gas (inclusive of emissions costs under the ETS). The modelling also indicates that battery storage systems and demand response could play a significant firming role, but current cost and performance projections indicate those resources cannot economically cover multi-day wind and solar generation intermittency or provide firming for dry years.

73. Earlier modelling in the Climate Change Commission's demonstration path projected the construction of 200 MW of fossil gas peaking plant by 2035.[35] More recently, the Electricity Authority's (Authority's) paper *Ensuring an Orderly Thermal Transition* indicates that investment in new fossil fuel generation is unlikely to be economically beneficial in the period up to 2032, assuming existing fossil fuel generation remains in operation.[36]

74. Are Ake's recent report[37] on battery storage highlights the potential for battery electric storage systems (BESS) in combination with intermittent renewables to enable excess energy produced during times of low demand to supply the grid during periods of high demand, minimising fossil fuel use.

75. BESS are playing an increasingly important role internationally in support of new intermittent renewables and grid stability. Australia has batteries under construction and planned that range from 400 MW to 850 MW for the Waratah Super Battery. In the United States a recent report showed a 1,263 per cent growth rate in BESS deployment over five years (from approximately 257 MW in 2016 to 3,508 MW in 2021) and forecasts the same level of growth to continue.[38] In the US, a third of proposed solar capacity now includes battery storage.[39]

76. The NZ Battery Project is focused on the resolution of the inter-seasonal dry year problem, but some options under investigation, including large-scale pumped hydro generation, could

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35 Climate Change Commission. (2022, August). *NZ ETS unit limits and price control settings for 2023-2027, Technical Annex 3: Electricity market modelling and retail price estimates*. Page 7. Available at: https://www.climatecommission.govt.nz/public/ETS-advice-July-22/Technical-annexes-and-supplementary-documents/Technical-Annex-3-Electricity-modelling.pdf

36 Electricity Authority. (2023, 13 June). *Ensuring and Orderly Thermal Transition: Consultation paper*. Page 13. Available at: https://www.ea.govt.nz/documents/3148/Ensuring_an_Orderly_Thermal_Transition_6_June_20231397102.1_1.pdf

37 Ara Ake. (2023, March). *Stationary Battery Energy Storage Systems Analysis.* Available at: https://www.araake.co.nz/assets/Uploads/March-2023_Ara-Ake-Battery-Report.pdf

38 Wood Mackenzie Power & Renewables and the American Clean Power Association. (2023, June ). *US Energy Storage Monitor*.

39 W Gorman et al. (2022, March). Are coupled renewable-battery power plants more valuable than independently sited installations? *Energy Economics*. Volume 107.

also provide an effective way to firm intermittent renewable generation including multi-day generation shortfalls.

77. Enabling demand side participation and distributed flexibility could also reduce the need for dispatchable generation and energy storage, for managing peak demand and renewable generation intermittency. Chapters 5 and 10 contain a focus on demand side participation and distributed flexibility.

## ENSURING SUFFICIENT INVESTMENT IN PEAKING AND FIRMING CAPACITY

78. Mechanisms such as those outlined in the Chapter 2 could also help to accelerate the delivery of firm capacity investment (such as peaking plants, battery storage systems or demand management) to replace the roles of fossil fuels in the electricity market. ‘Capacity mechanisms’ are investment support measures that specifically target firm or dispatchable capacity, whether from generation, battery systems or demand response.

79. Broadly speaking, capacity mechanisms exist to ensure that there is sufficient energy capacity when it is needed. Some countries in Western Europe, and the United States have implemented these mechanisms where there have been concerns that the traditional dynamics of an energy-only market do not provide sufficient incentives to invest in reliable capacity. These mechanisms include ‘capacity markets’ that operate as part of an electricity market as well as mechanisms that add processes outside the market, often through direct government funding or regulation as described in Box 2 on the following page.

**Box 2: Capacity markets**

Capacity market mechanisms (usually referred to as capacity markets) generally supplement wholesale energy payments though an arrangement that pays generators for being present and available to operate. Many capacity markets also require that energy purchasers must hold cover reflective of their assessed share of demand. This can be through contracts or certificates for generation or demand response. The requirement to hold cover creates a regulated revenue stream for suppliers. Such arrangements are separate from spot market payments and many designs also have penalties for failure to provide capacity when requested.

There is a broad range of capacity mechanisms in use internationally. Most traditional capacity mechanisms were designed to operate within fossil fuel dominated markets with predictable operating characteristics. This allowed for a consistent set of operational rules. However, in a market dominated by renewable technologies that are rapidly evolving, it may prove difficult to maintain a consistent and fair set of operational rules.

**United Kingdom Capacity Market**

The UK launched a capacity market in 2014. The capacity market provides a payment for reliable sources of capacity through auctions, alongside normal wholesale market revenues, to ensure the market delivers energy when needed for security of supply. Auctions are usually held about four years in advance of the delivery date, with another auction for a smaller amount of capacity held a year before delivery. To date 5.78 GW of capacity has been procured, 2.6 GW from gas-fired power plants, 1.4 GW from nuclear reactors and 627 MW from battery storage. The auction is not aimed primarily at securing new capacity, but on ensuring capacity to meet generation targets. Around four-fifths of the capacity procured in the auction was from existing power assets.[40]

80. The implementation of a capacity market mechanism into New Zealand's current energy-only market could be very disruptive, requiring considerable work to assess its efficacy and then to develop a workable design and implementation. Some recent reviewers of the New Zealand market have concluded that a capacity market is not required, and that the wholesale spot market is key in providing efficient incentives or signals for energy use and investment.

81. The Authority's paper *Ensuring an Orderly Thermal Transition* is consistent with the view expressed by MDAG that capacity mechanisms are more appropriate in a world in which capacity shortages are relatively simple and predictable and are not warranted in New Zealand at this stage.[41] In its recent work, the Authority notes that while capacity mechanisms internationally have been largely effective in meeting objectives of ensuring adequate capacity, it is generally thought they can lead to higher prices because of a tendency to be risk averse and over procure. The Authority also notes capacity mechanisms have a mixed record in terms of operational success particularly when contracted plant fails to be available when called on.

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40 Nora Buli, Deep Vakil and Marwa Rashad. (2023, 15 February). UK power capacity auction prices fall from record. *Reuters*. Available at: https://www.reuters.com/world/uk/uk-power-capacity-auction-prices-fall-record-2023-02-15/

41 Electricity Authority. (2023, 13 June). *Ensuring and Orderly Thermal Transition: Consultation paper*. Pages 39-42

82. In addition, capacity mechanisms need to be carefully designed to not favour incumbent fossil fuel generation, thereby artificially extending the economic life of these generators, and delaying the transition to a low carbon energy system.

83. Internationally, some capacity mechanisms that have been implemented as government policies with the intention to bring forward additional capacity relative to a prescribed target level. These may operate by removing risk for investors through some form of revenue stabilisation, or by placing an obligation on purchasers of electricity. Capacity mechanisms which add processes to the energy-only market generally provide some form of side payment, or revenue stabilisation, or place an obligation on purchasers of electricity. They are intended to bring forward additional capacity against a target level by removing risk for investors, or the placing of an obligation on purchasers, rather than providing an income stream for plant availability.

84. One example of a capacity mechanism that provides revenue stabilisation is the Capacity Investment Scheme (CIS) which is currently being investigated by the Australian Federal Government.

85. The proposed CIS is conceptually similar to CfDs and PPAs, as its primary purpose is to bring forward or guarantee new investment. The CIS will determine a capacity target level and be designed to secure or support new investment revenues to bring forward new capacity consistent with the target. The capacity built will then operate within the current Australian market with the only difference being that these facilities' income streams will be supported by a side agreement with the Australian Federal Government.

86. A capacity mechanism such as the Australian CIS establishes an ex-ante ('before the fact') payment mechanism to support the contracted party with some form of revenue support. At the time of writing the CIS is still in the conceptual design phase with a pilot auction expected later in 2023. A mechanism like the CIS may take the form of a CfD or a collar (cap and floor) on revenues and may include some form of revenue sharing in exchange for this risk management.

87. In the Australian context, the CIS is likely to be focused heavily on bringing forward new generation to replace the approximately 14 GW of coal plant that is expected to retire over coming decades. In a New Zealand context, such a scheme could be directed largely at incentivising new firming capacity or storage, rather than energy projects, or could be designed to incentivise the addition of storage to energy projects (such as inclusion of battery storage systems with investments in intermittent renewables – as outlined in some of the examples below).

88. The Australian CIS, together with examples of similar schemes designed to provide side payments or revenue stabilisation to incentivise investment in firm capacity or storage, are outlined in Box 3 below.

**Box 3: Examples of capacity mechanisms**

**Australian Capacity Investment Scheme**

The Australian CIS is intended to identify and fill gaps in dispatchable power across Australia with zero emissions technologies. Under the proposed design, the Commonwealth Government will work with the Australian Energy Market Operator (AEMO) and States/Territories to assess both the short and long-term needs of every region on an annual basis, to define the types of technologies best suited to the needs of that region, which will be a mix of zero emission dispatchable generation and storage.

Once the right mix of capacity is identified, an open competitive tender will be conducted to fill the capacity need. The best value projects that can meet the needs of the region at the lowest cost will then be selected.

Projects that are successful will be awarded a long-term revenue underwriting agreement, with a revenue floor that is expected to cover costs, and a ceiling above which revenues are shared back. In return, projects are required to begin and finish construction by set dates and operate efficiently to deliver the stability needed by consumers.

**Alberta's Renewable Electricity Program**

Alberta, Canada has a similar auction-based incentive scheme for new renewables, which may be supported by storage. Successful projects will be privately funded and supported by reinvesting a portion of carbon revenues from large industrial emitters. This includes projects where intermittent renewables have been paired with battery energy storage systems to enable firm capacity to be bundled with new intermittent renewables.

**Victorian Government Renewables Auction Scheme**

The Victorian Government Renewables Auction Scheme (discussed in Box 1 above, in relation to CfDs) also includes support of new battery energy storage. Under 'VRET2' six projects have been successful bringing forward 623 MW of new renewable generation capacity and delivering up to 365 MW and 600 MWh of new battery energy storage systems.

**New South Wales Long Term Energy Service Agreements**

In accordance with its Electricity Infrastructure Roadmap, New South Wales (NSW) operates a support scheme known as Long Term Energy Service Agreements (LTESA) for new renewable and storage options within its five defined renewable energy zones (REZs). LTESA contracts are intended to reduce price risk to improve project bankability, and:

- support higher debt gearing
- support a more competitive debt package
- attract a wider group of financiers and investors.

The LTESA contract term is longer than typical hedge or risk management arrangements available to developers, providing financiers and borrowers optionality through refinancing.

Firming LTESAs have additional features such as a longer term (up to 40 years) to support the long asset lives of these technologies.

**Canadian refundable investment tax credits for energy storage**

Canada's government announced in late 2022 that it will introduce tax incentives for clean energy technologies, including solar PV, battery storage, and hydrogen. A refundable tax credit is proposed equivalent to 30 per cent of the cost of capital investment into electricity generation systems,

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| stationary electricity storage systems, low-carbon heat equipment and industrial zero-emissions vehicles and related charging or refuelling equipment.<br><br>Projects that do not meet requirements on local labour conditions will get a 10 per cent reduction in the minimum tax credit rate. A higher rate of investment tax credit, 40 per cent, will be available for hydrogen projects that meet all eligibility requirements on carbon intensity. |
| **Australian Energy Market Operator's 'AEMO Services'** |
| AEMO has an arm, 'AEMO Services', which is appointed as the NSW 'Consumer Trustee' and has a central role in co-ordinating long-term planning and investment in energy generation, storage and transmission in NSW. Tenders have been run for storage and battery solutions, with the most recent Tender Round 3, launched on 22 May 2023 seeking an indicative amount of 2500 GWh (around 950 MW) of generation and 550 MW of long duration storage.[42] |

89. Further to the above examples of support measures, other countries are also specifically targeting policy interventions to incentivise the installation of BESS. Measures include subsidies to ease the burden of initial installation on consumers or providing exemptions from related taxes. Back in 2018, Germany was subsidising 30 per cent of the installation costs of BESSs coupled with solar power generation, with support increasing from €25 million in 2013 to €30 million between 2016 and 2018.[43]

### *Retailer reliability obligations*

90. BCG's *The Future is Electric* report recommended for consideration a 'Retailer Reliability Obligation' (RRO) as a measure to improve assurance about capacity levels. A RRO usually involves a central agency (for example , the system operator) forecasting demand for capacity in the future and then requiring retailers to obtain an amount of capacity certificates based on their anticipated load. Retailers buy these certificates from producers through auctions or intra-group trade with the price of the certificates (capacity) set by the market.

91. An example is Australia's RRO (see Box 4 below) operated by AEMO. AEMO has a role to identify any potential reliability gaps in each region of the Australian National Electricity Market (NEM) in the coming five years using its 'Electricity Statement of Opportunities'. If AEMO identifies a material gap three years and three months out, it can apply to the Australian Electricity Regulator (AER) to trigger the RRO by making a 'reliability instrument' which defines which entities are required to hold a net contract position for the assessed reliability gap period. The South Australian Minister can also trigger the RRO within South Australia.

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42 AEMO Services. *Tender Round 3 – Generation and Long Duration Storage Infrastructure*. AEMO Services website. Available at: https://aemoservices.com.au/tenders/tender-round-3-generation-and-long-duration-storage

43 Asian Development Bank. (2018, December). *Handbook on Battery Energy Storage System.* Available at: https://www.adb.org/sites/default/files/publication/479891/handbook-battery-energy-storage-system.pdf

**Box 4: Australian Retailer Reliability Obligations**

Australia's RRO is a targeted example of a retailer capacity obligation. It is intended to provide strong incentives for market participants to invest in the right technologies in regions where it is needed, to support reliability in the NEM. Under this scheme:

- AEMO identifies potential reliability gaps in each NEM region in the coming 5 years using its Electricity Statement of Opportunities.
- If AEMO identifies a material gap 3 years and 3 months out, it will apply to the regulator to trigger the RRO.
- When the AEMO applies to trigger the RRO, liable entities are on notice (via the reliability instrument) to enter sufficient qualifying contracts to cover their share of a one-in-two-year peak demand.

A 'Market Liquidity Obligation' placed on generators also ensures there are contracts available to smaller market customers by requiring certain generators in each region to make contracts available to the market.

If AEMO is required to procure additional resources to address the shortfall in capacity, entities whose share of load is not covered by qualifying contracts will be required to pay a portion of the costs for the 'Procurer of Last Resort', up to an individual maximum of $100 million.

### *Issues to consider with incentives for firming capacity*

92. A key consideration in the implementation of any capacity mechanism is determining how much and what type of generation (or demand response) is procured. There would be a need to determine security and reliability standards to understand how much capacity was required for different time periods for which it is needed (ie, peaking, calm, cloudy periods or seasonal capacity), noting that different types of generation or storage can provide dispatchable capacity across one or more of these time periods. This would require an institution or agency to coordinate and operationalise the role – this is discussed further below.

93. Care would also be needed in any capacity mechanism design to minimise impacts on affordability which will be affected by how much capacity is incentivised and how any mechanism is funded (whether through general taxation, or a levy on electricity market participants).

94. There is also a question of the type of firming capacity that is incentivised. For example, if a capacity mechanism provided incentives for thermal capacity, it would be important to ensure that it did not inadvertently act to keep fossil fuels in the market for longer than they are needed. Issues relating to retention of fossil fuels (fossil gas peaking and slow start thermal plant) for as long as they are needed (and no longer) are discussed further in a following section of this chapter.

95. Although additional investment in dispatchable capacity or storage should improve reliability and security, there are potential risks from overbuilding.[44] A general criticism of capacity

[44] Though in an environment of high continual load growth the effect may be more from early building, rather than overbuilding.

markets is that they can be prone to over-procurement as decision-makers on capacity levels tend to be risk averse, leading to higher costs. For example, BCG cites that Western Australia's capacity market caused an estimated 23 per cent overbuild in 2016-17, representing a $116 million incremental cost per year. However, as the examples listed earlier indicate, there is a strong push across many governments – particularly in Australia – to introduce additional mechanisms to ensure sufficient investment during the transition.

96. A key requirement in any such mechanism is a robust process to set or establish valid procurement targets – to avoid the risk of over procurement – and a flexible process for procurement that can adjust to changing circumstances and technologies. The latter could take the form of an auction, that was only run periodically when and if required and had flexibility around the type of capacity technology it procured.

97. Additionally, in drawing lessons from international schemes to New Zealand, we should keep in mind factors about the electricity system in New Zealand that make it distinct from others, such as:

- New Zealand is a small energy market and is unlikely to drive global technological change. There is therefore less economic rationale to provide more support for emerging technologies, which will (or will not) mature elsewhere with or without investment from New Zealand.
- A complication in considering such a mechanism for New Zealand would be the time scale that the capacity needs to operate on. That is, whether an approach would need to factor in different types of capacities to meet the range of needs including peaking, calm, cloudy periods, and dry year needs, and how it would integrate or align with the outcome of the NZ Battery Project.

### *Questions*

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| 4. | Do you think measures could be needed to support new firming/dispatchable capacity (resources reliably available when called on to generate)? If yes, which kind of measures? What needs do you think those measures could meet and why? |
| 5. | Are any measures needed to support storage (such as battery energy storage systems or BESS) during the transition? If yes, what types of measures do you think should be considered and why? |
| 6. | If you answered yes to question 4 or 5 above, should the support be limited to renewable generation and renewable storage technologies only or made available across a range of other technologies?<br>Keep in mind that fossil fuels are generally the cheapest option for firming, though this may change over time as renewable options (particularly batteries) become more efficient and affordable. |
| 7. | If you answered yes to question 6 above, what are the issues and risks with this approach? How could these risks and issues be addressed? |

## INVESTMENT IN FOSSIL GAS PEAKING PLANT DURING THE TRANSITION

98. One specific instance of dispatchable capacity that we may need to consider in transition is the role that fossil gas plays for managing variability in the system. This is because gas may be needed to play a strategic role in the electricity system in supporting development of new renewables, particularly intermittent renewables. It may also be needed in the short term to support security of supply and affordability while New Zealand expands the use of its electricity system to decarbonise other areas such as transport and industry.

99. Several parties (such as MDAG, BCG) have noted that there may be a role for new gas peaking, as well as the need to retain existing fossil fuelled generation for a period to maintain reliability and affordability during transition, and that such investment may not be forthcoming if investors judge it to be too risky.

100. Additionally, depending on pathways for phase out of fossil gas and arrangements in the gas market for supply to the electricity market, there may be future challenges relating to the cost and availability of natural gas. Issues concerning future gas supply are covered in more detail in the Gas Transition Plan Issues Paper (that is also currently being consulted on).

101. If such generation is critical for security of supply in the short term but the economics of the investment are uncertain and there are no other alternatives, then a mechanism to incentivise this investment might be warranted. Such a mechanism would need careful design, with emissions targets in mind, especially if the plant does not utilise carbon capture, use and storage.

102. While it was not for a peaking station, there is a recent example of government support in New Zealand to underwrite the construction of a fossil fuelled generator. This was in 2004 when Genesis and the Government entered a risk sharing deed or agreement that helped secure the construction of the Huntly e3p 385 MW station through the Government financially underwriting its gas supply. If called on, the deed required the Crown to make payments directly to Genesis for gas shortfalls instead of bearing the risk indirectly through its equity ownership of Genesis. Due to favourable gas prices this deed was never called on before it expired.

### *Questions*

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| 8. | Are any measure(s) needed to support existing or new fossil gas fired peaking generation, so as to help keep consumer prices affordable and support new renewable investment? |
| 9. | If you answered yes to question 8 above, what measures should be considered and why? What are the possible risks and issues with these measures? |
| 10. | If you answered yes to question 8 above, what rules would be needed so that fossil gas generation remains in the electricity market only as long as needed for the transition, as part of phase down of fossil gas? |
| 11. | Are there any issues or potential issues relating to gas supply availability during electricity system transition that you would like to comment on? |

# 4 Managing slow-start fossil fuel capacity during the transition

103. Given the current critical role of baseload thermal plants for dry year security, early departure or closure would raise concerns over future supply, particularly for longer term storage. New intermittent generation should cover any shortfall arising from the retirement of baseload thermal in a normal hydrological year. However, in a dry year security is less certain with a highly renewable generation mix. This is one rationale which supports the NZ Battery Project.

104. Modelling undertaken for Boston Consulting Group (BCG), the Market Development Advisory Group (MDAG), and Transpower generally assumes the Taranaki Combined Cycle (TCC) plant closes in 2024, in line with public announcements by Contact Energy, and the Te Rapa cogeneration plant closes in 2023. Different modellers make different assumptions on the exact closure dates for other slow start thermal plants, though all assume total closure or at least removal from the electricity market into some form of dry year reserve by the early to mid-2030s.

105. MDAG claimed that premature closure is unlikely because thermal plant operators should be able to earn sufficient revenue from the wholesale market to cover a plant's costs if it is economic to retain that plant.[45] MDAG also argued that its options B1-B4 will help to reduce the risk of premature closure. [46]

106. This chapter considers measures that have been proposed and other measures that could be considered to help ensure sufficient thermal generation remains available as we transition.

## WHAT IS ALREADY UNDERWAY?

### *Electricity Authority paper on thermal retirement*

107. A recent Electricity Authority (Authority) paper[47] on thermal transition suggested that thermal plants not already scheduled for closure are likely to remain operational as they will have opportunities to earn revenue sufficient to cover their forward costs.

108. The Authority comments however, that thermal plants (and especially Huntly Power Station's three Rankine units) would have significant volatility in their net cashflows if reliant solely on spot market revenues. This is shown in Figure 3 below.

109. Security of supply is heavily influenced by weather, particularly a dry year. Modelled demand for thermal plant generation (while lower in the early 2030s) increases significantly in dry

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45 Market Development Advisory Group. (2022, December). *Price discovery in a renewables-based electricity system: Library of options*. Paras 3.84. Available at: https://www.ea.govt.nz/documents/1247/MDAG-Library-of-options-FINAL-1.pdf

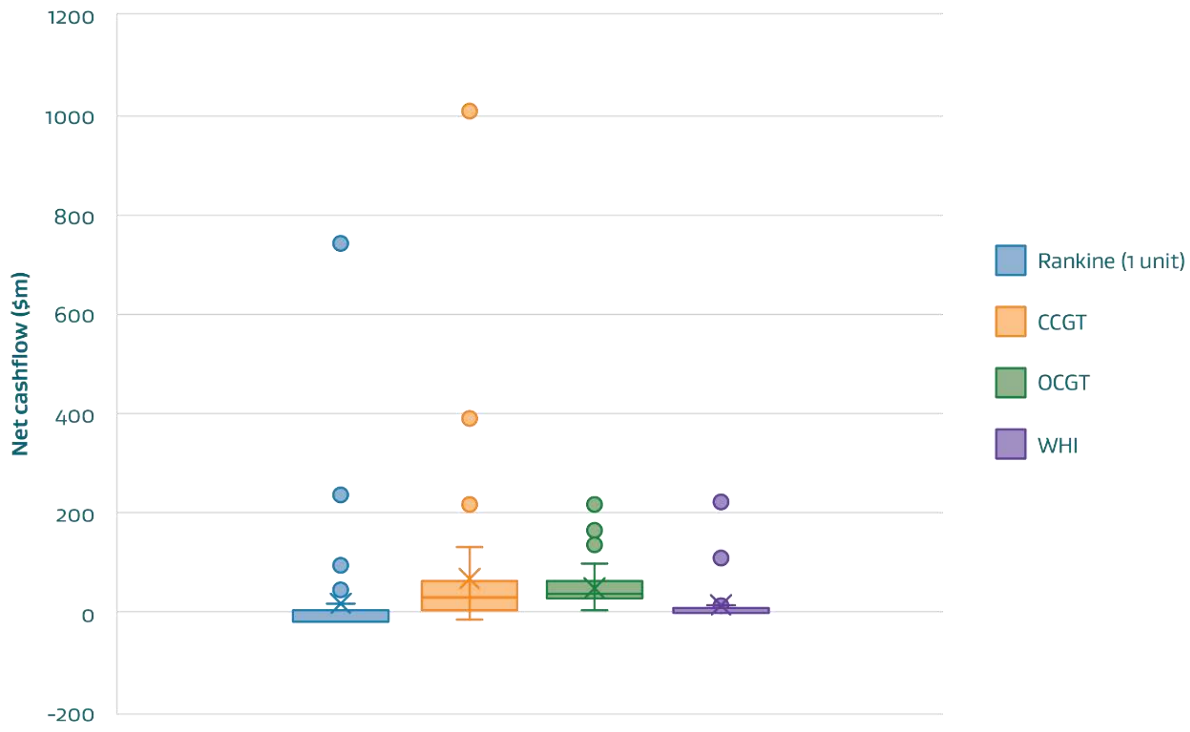
46 See: section B1 – Greater transparency of hedge info (especially non-base load) covering offers, bids + agreed prices, section B2– Market-making for longer dated futures (for price discovery), section B3 - Publish aggregated information on pipeline of new developments, energy and capacity adequacy, and section B4 -Enhance stress testing regime.

47 Electricity Authority. (2023, 13 June). *Ensuring and Orderly Thermal Transition: Consultation paper*.

years and the cashflows for thermal units in dry years (shown by the dot in Figure 3) are strongly positive, even though revenue for Huntly Power Station's Rankine units on average drops below zero.

110. Figure 3 illustrates a base case where one Rankine unit will be revenue adequate with the remaining two Rankine units being negative on an average basis. While the Authority notes this result is sensitive to assumed fuel prices, the modelling shows it is unlikely that there will be enough demand to support the retention of a CCGT (Huntly's e3p) and more than one Rankine unit by 2032.

*Figure 3: Net cashflows by thermal generation type*

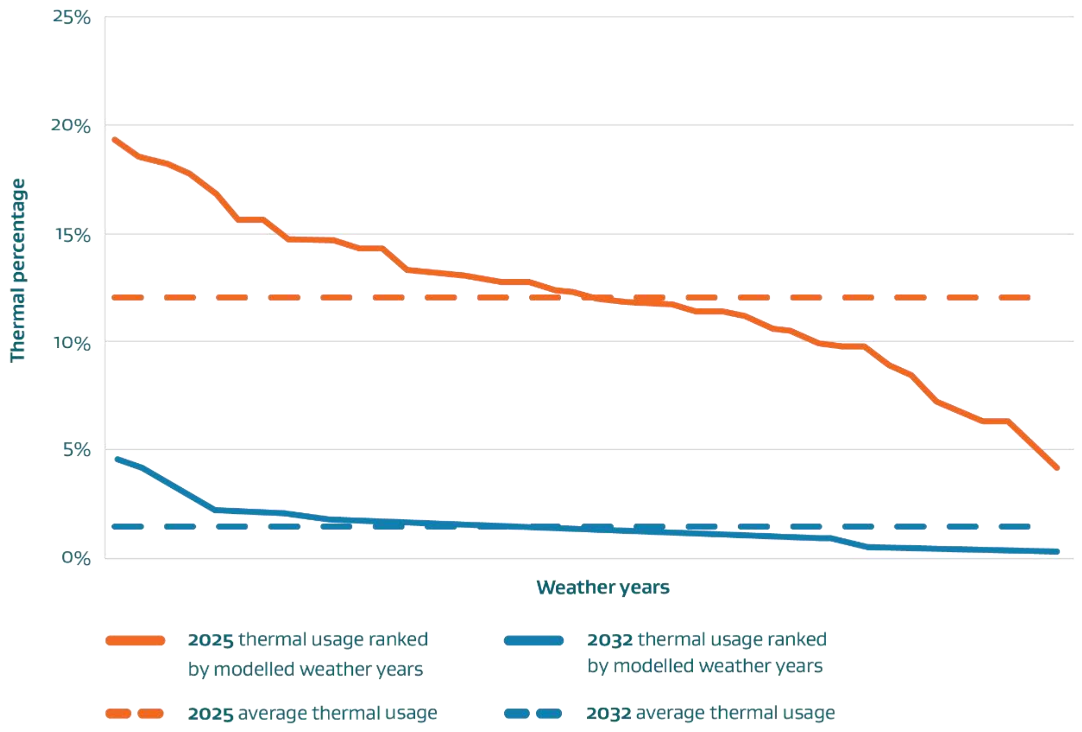



Source: Electricity Authority, May 2023.

| | |
|---|---|
| **Key:** | |
| **Rankine:** | **Huntly Rankine (coal) units** |
| **CCGT** | **Combined Cycle Gas Turbine (eg, Huntly e3p)** |
| **OCGT** | **Open Cycle Gas Turbine (eg, Stratford OCGT)** |
| **WHI** | **Whirinaki diesel powered station** |

111. This point is further illustrated in the Authority's chart (Figure 4 below). The chart shows two separate lines for 2025 and 2032 respectively, the dotted line being the average percentage of thermal generation expected in each year, with dry years at the left-hand side of the chart and wet years on the right.

*Figure 4: Thermal generation percentage across weather years*




Source: Electricity Authority, May 2023

**Key:**

| | |
|---|---|
| **Solid orange line** | **2025 thermal usage ranked by modelled weather years** |
| **Dotted orange line** | **2025 average thermal usage** |
| **Solid blue line** | **2032 thermal usage ranked by modelled weather years** |
| **Dotted blue line** | **2032 average thermal usage** |

112. In the Authority's analysis, by 2032 the expected level of thermal generation is very low across most weather years though it is expected to be higher for dry years (solid blue line) indicating that in dry years there is still a role for fossil gas generation in the absence of affordable alternatives.

113. The Authority in its thermal transition paper considers several options that could address concerns about insufficient thermal capacity during the transition as noted earlier. The Authority also in its recent competition decision paper notes that it will continue to monitor and analyse thermal generation transition risks in the context of demand to 2030, its role in hydro firming and more prevalent solar and wind generation, and options to mitigate any transition risks.

114. The assessment of the Authority is that these risks are low, and it is taking steps to monitor the situation. However, the lead time to develop a remedy, especially if it requires new regulations, may be long compared to the time available for development if a dry year situation arises. Accordingly, this section of the paper considers issues around strategic reserves, and the Authority's option G: introduce minimum notice period for plant capacity reductions, as options to be evaluated further as potential backstops, noting that the Authority is also undertaking additional analysis to assess the risk of thermal retirement as the situation evolves.

### *Minimum notice for reductions in plant capacity*

115. Following the sudden closure of several thermal plants in Australia, such as the Hazelwood plant in Victoria in 2016, Australia introduced a requirement for a minimum closure notice of three years for thermal plant operators, although generators can apply to the regulator for a shorter notification period.

116. New Zealand has no such requirement in relevant regulations (eg, *the Electricity Industry Participation Code 2010*) and faces the same potential risk of limited notice of plant closure. While plant operators in New Zealand have previously closed plant with limited notice, this has been in an environment of capacity surplus where intermittent generation levels were lower. In today's transition environment the impacts on security of supply of plant closure may be greater, especially if such a closure coincides with or is followed by a dry year. The Authority's preliminary assessment is that the option of a minimum notification period before closure could prove useful, but it does not recommend proceeding with it at present.

## FURTHER MEASURES TO CONSIDER?

117. MBIE previously consulted on the concept of a strategic reserve in the 2019 *Accelerating Renewable Energy and Energy Efficiency* discussion paper. This paper discussed a mechanism whereby baseload thermal plant would be ring-fenced outside of the energy market and only used in an emergency when there was an energy shortage, noting similar schemes in both Belgium and Germany and the similarity of this option to the reserve scheme operated by

the Electricity Commission (the Authority's predecessor) until 2008[48], when the Government owned the Whirinaki Power Station.

118. In 2021 Contact Energy suggested a 'ThermalCo' model[49], where ownership and operation of existing thermal assets and upstream fuel supply contract could be consolidated, with the mandate to offer transparent and liquid risk management products. This option, recently no longer pursued by Contact Energy, was an industry led solution that would require cooperation among several stakeholders. While stakeholders were unable to agree on the value of this concept, it, or a derivative of it, may still have merit as a government sponsored process in the future.

119. In terms of other non-thermal options, the NZ Battery Project is focused on the resolution of the inter-seasonal and inter-year dry year problem. In addition to investigations relating to Lake Onslow, the NZ Battery Project is looking at a portfolio of technologies including biomass generation and seasonal geothermal capacity. One or more of these technologies, along with green-fuelled peakers, may be able to assist in providing a dry year solution as well for the inter- or multi- day issue. Additionally, Genesis Energy has been investigating the potential to use biomass in Huntly Power Station's Rankine units, and recently undertook a trial of this technology.[50] Following this trial, Genesis is working with other businesses to determine whether it is possible to develop a supply chain at the scale needed to support a local biomass industry to provide a reliable, affordable and sustainable alternative to coal.

120. Additionally, as the amount of intermittent generation grows, the role of hydro is expected to change providing more of a firming role when less intermittent generation is available. Currently 832 GWh of hydro storage exists as contingent storage that can be made available for generation at specific times, under defined rules, to mitigate the risk of shortage (eg, Lake Tekapo 220 GWh, Lake Pukaki 545 GWh and Lake Hawea 67 GWh). An argument could be made that it would make sense to have a greater volume of storage held in reserve as contingent storage as the level of intermittent renewables increase. However, the role of hydro is already expected to change as a greater level of intermittent renewables comes into the system. Furthermore, any change to existing contingent storage arrangements, even if technically possible, would require consideration of how such options could be delivered without significantly affecting the value of the hydro generators while at the same time ensuring compliance with existing resource consents on lake levels, river flows and contingency rules.

121. More recent analysis has also considered the concept of a strategic reserve and concluded that such a mechanism is unlikely to be effective:

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[48] The Whirinaki scheme was disestablished in 2009 as it was found that market participants anticipated and planned for the Whirinaki Power Station's contribution, and it was argued the scheme was suppressing generation investment by capping energy prices.

[49] Contact Energy. (2021, 15 November). *Thermal Co: Enabling Aotearoa's transition to 100% renewable electricity generation*. Contact Energy website. Available at: https://contact.co.nz/aboutus/media-centre/2021/11/15/thermal-co-enabling-aotearoas-transition-to-renewable

[50] Genesis Energy. (2023, 22 February). *Genesis' biomass trial successful.* Genesis Energy website. Available at: https://www.genesisenergy.co.nz/about/news/genesis-biomass-trial-successful

- In a recent options paper, MDAG considered a strategic reserve (Option B10) and recommended against it as they argued it is likely to raise costs and not increase security.[51] MDAG noted that strategic reserve schemes can undermine incentives for contracting and could act to suppress investment and prolong the operation of thermal plant beyond when it would normally retire, thereby delaying the introduction of renewable alternatives and threatening emissions targets.
- BCG's *The Future is Electric* report also considered and recommended against strategic reserves as an addition to the New Zealand market.[52] This option involved contracting contingency reserves, where a central body contracts with participants to provide reserve capacity, and a reserve portfolio where government underwrites the continued operation of a portfolio of reserve assets that would otherwise have exited the market. BCG noted that strategic reserves can be designed to maintain investment incentives although this would be difficult to achieve.
- Most recently, the Authority's paper on thermal transition options also considered a strategic reserve.[53] The Authority identified a number of key challenges with a strategic reserve; noting that it could undermine normal contracting and investment, it can be difficult to keep a strategic reserve quarantined, in a tight market there may be pressure to use it to lower prices and it can be difficult to maintain a reserve as only a temporary or short-term measure. The Authority does not consider that a strategic reserve is needed to mitigate risks during the transition.

122. The negative assessments noted above are largely predicated on the assumption that sufficient new generation investment, including batteries and demand response, will occur in time and that significant and/or consecutive dry year events do not occur.

123. However, because of the small number of thermal plants in New Zealand providing dry year security, premature closure coinciding with a dry year could still pose a significant security of supply risk which would have high economic impact. Noting the negative cashflow for the Rankine units predicted by the Authority (see Figure 3) and the Authority's observation that thermal may be needed much more in a dry year, and Transpower's security of supply assessment (SOSA) on potential capacity issues with higher intermittency, it is worthwhile considering this issue further.

### *Questions*

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|---|---|
| 12. | Do you agree that specific measures could be needed to support the managed phasedown of existing fossil fuel plants, for security of supply during the transition? |

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51 Market Development Advisory Group. (2022, December). *Price discovery in a renewables-based electricity system: options paper*. Paras 11.9-11.16.

52 Boston Consulting Group. (2022, October). *The Future is Electric - A Decarbonisation Roadmap for New Zealand's Electricity Sector*. Page 15.

53 Electricity Authority. (2023, 13 June). *Ensuring and Orderly Thermal Transition: Consultation paper*.

| | |
|---|---|
| 13. | If you answered yes to question 12 above, what measures do you think could be appropriate and why? What conditions do think you should be placed on plant operation?<br>For example, do you have any views on whether there should be a minimum notice period for reductions in plant capacity, and/or for placing older fossil fuel plant in a strategic reserve? |
| 14. | If you answered yes to question 12 above, what are the issues and risks with these measures and how do you think these could be addressed? |

# 5 The role of large-scale flexibility

124. As the share of intermittent renewable generation increases, participation of demand response in the market is likely to be increasingly important. Large industrial users in New Zealand (wood, pulp, paper, printing, metals sectors) consume around one third of New Zealand's electricity demand and those with the ability and willingness to shift and/or curtail demand could provide demand response flexibility back to the market.

125. Demand response can provide a source of controllable, flexible resource to firm variable renewable generation, and can send valuable price signals to the market.[54]

126. We use the term 'large-scale flexibility' to describe demand response from distributed or grid connected large industrial energy consumers. Distributors and retailers can also offer demand reductions. Large-scale flexibility includes:

- demand response (changing demand in response to price signals)
- demand management (pre-contracted demand reduction with large scale consumers)
- 'behind the meter' injection or battery dispatch to reduce grid-presented demand without affecting operation.

127. Large-scale flexibility can provide an economic alternative to new generation investment and play a significant role in reducing peak demand and in providing firming. As the use of flexibility increases, the overall cost to supply electricity may fall as more expensive generation is displaced by demand response.

128. Modelling by the Market Development Advisory Group (MDAG), Boston Consulting Group (BCG) and others anticipates that in the future the energy system will utilise significant volumes of large-scale flexibility from industrial, commercial and, in coming decades, residential sources. To ensure the market fully realises this potential, it will require increased knowledge of the benefits of demand response, significant investment in new technology, systems and potentially new market policy measures.

129. Virtual Power Plants (VPPs) can also offer distributed flexibility – over time uptake of this kind of smaller scale demand flexibility will increase and play a more significant role in providing firming. Uptake of distributed flexibility is considered in Chapter 10, which explores how we can support flexibility market development to enable provision of the range of benefits flexibility can provide (including firming) and developing a smart electricity system.

130. This chapter considers whether we have the right settings in place to incentivise the provision of efficient large-scale flexibility and the maintenance of existing ripple control by distributors.

[54] Load-shifting describes most short-term, peak-related demand response. Load-curtailment describes dropped load that does not return in the short term, whether in response to high prices or an outage.

## WHAT IS ALREADY UNDERWAY?

### *Real time pricing and dispatch notification products*

131. The Electricity Authority (Authority) implemented real-time pricing for the wholesale market in November 2022. This means the settlement price for each trading period is calculated at the end of the trading period and published immediately. This has increased the level of accuracy and certainty for wholesale spot prices and opened up opportunities for greater demand side participation.

132. The final phase of the Authority's Real Time Pricing project came into operation in April 2023, and now enables participants to bid and offer demand flexibility and distributed energy resources into the wholesale market using a new 'dispatch notification' product and enhancements to an existing 'dispatchable demand' product.

133. While the focus of this chapter is on large industrial consumers, the dispatch notification product provides a low-cost path for smaller-scale providers (such as residential, solar and battery system aggregators) to bid and offer their resources into the wholesale market. Allowing these renewable, distributed resources to interact with the market can contribute to displacing more expensive generation resources such as fossil fuel plants.

134. The enhancements to the existing dispatchable demand will also allow large industrial consumers to bid in demand management in a way that better suits the physical constraints of their plant and processes. Large industrial consumers can now manage their exposure to high electricity prices by having part of their load based on a fixed price and part of their load exposed to the spot price, but with the ability to bid demand response for that exposed load into the wholesale market.

135. Even with these demand response mechanisms in place, some large-scale industrial customers, distributors and retailers may not consider they receive compensation that fully reflects the cost and/or value to wider New Zealand society of their demand response. Value streams (or avoided costs) that they consider may not be currently fully reflected include:

- the lost value to the 'demand-responding party' of lower (or stalled) production
- the value to all wholesale market customers if the spot price is lower for market participants as a result of the demand response
- the wider benefit to New Zealand of the lights staying on (if, without the response, a tight situation would have led to temporary outages).

136. The future challenge will be to identify opportunities to reduce the cost of demand response participation through providing information, education and contract products.

### *Winter 2023 measures (and beyond)*

137. The Authority is progressing a suite of measures in preparation for winter 2023 and beyond to manage risks and address potential strains in the New Zealand electricity system. These measures are not targeted solely at demand response. However, they are likely to provide better information for participants considering demand response. The System Operator has worked with the Authority to develop four measures ahead of this winter. These are:

- more information to market participants on headroom in the supply stack
- forecast spot prices provided to participants under demand sensitivity cases
- the System Operator to review wind offers based on external forecast
- better clarity on availability and use of 'discretionary demand' control (such as ripple control).

138. The first three measures will improve the quality of information available to market participants and enable better-informed resource commitment decisions (both generation and demand management). The final measure amends the *Electricity Industry Participation Code 2010* so that the System Operator now has an accurate awareness of discretionary load. The effectiveness of this measure will be reviewed at the end of winter 2023.

139. After winter 2023, the Authority also plans to consider whether there is a need to introduce a new integrated ancillary service to offset increased uncertainty in net demand. The Authority notes if any new ancillary service is proposed it would need to be technology agnostic, neutral between demand and supply side resources and integrated with the spot market. This would continue to promote competition and ensure it does not act as a subsidy for unproductive plant.

140. The Authority also indicated it will investigate if other mechanisms may be needed to accelerate the development of an efficient demand response market. The Authority cautioned providing payments separate from the electricity market as this could undermine current investments in demand response and discourage investment, innovation, and competition.

### *Industry response mechanisms*

141. Electricity intensive industrial users have the potential to be the biggest source of demand-side flexibility in the future. They could also make material cost savings by reducing usage at times of higher wholesale prices. Industrial users have started to provide demand response flexibility both independently and with government support. Large scale industrial users are indicating their interest in playing a role in providing demand response.

142. For example, In April 2023 the New Zealand Aluminium Smelter (NZAS) and Meridian Energy announced a new agreement with the intention to provide New Zealand with support to manage periods of peak demand and low hydrology. Meridian has the right to call up an option for NZAS to reduce energy consumption by up to 50 MW. This call option has a two-day notice period and is expected to be used to manage dry year risk, rather than risks associated with tight supply at times of peak demand. NZAS has also offered shorter term demand response to the wider New Zealand market that could be valuable in tight supply situations.

143. In May 2023, the Government announced a partnership with New Zealand Steel to help co-fund an electric arc furnace to replace the existing steelmaking furnace and two of the four coal-fuelled kilns. New Zealand Steel agreed in principle to a 30 MW 'off-peak hedge', under a 10-year electricity supply agreement with Contact Energy to provide electricity supply for the new furnace. Details of that demand response arrangement are not publicly available.

144. The participation of large energy users providing demand flexibility comes at a cost. Full time participation in the electricity market is not the 'core' business of large-scale industrial users, and to fully engage, they require an increased level of financial and market certainty to make any commitments over the longer term. The current uncertainty over future value streams to provide a level of flexibility (particularly associated with wholesale electricity spot prices/energy arbitrage) creates significant risk for large users.

145. In its recent consultation MDAG noted that "for larger consumers, financial contracts need to be developed to underpin their investment in enabling demand side flexibility". MDAG proposes developing standardised hedge products to provide reassurance and certainty. These products could enable large consumers to smooth volatile revenues from flexibility.

146. A demand aggregator is a market participant that acts as a broker to optimise strategies, technology and returns for electricity consumers with demand flexibility. Enel X, for example, has been aggregating demand flexibility from commercial and industrial consumers and offering it as 'interruptible load' in New Zealand's instantaneous reserve market since 2009.

147. There is evidence that retailers are increasingly exploring demand flexibility with the consumers they supply. For example, Contact Energy said in a recent investor presentation that demand response is introduced wherever possible when entering into new supply contracts, and there is high customer appetite for demand response mechanisms to be packaged into new contracts.[55] Contact plans to have contracted more than 100 MW of flexible demand by 2026.

148. The government and energy market participants have made initial efforts to highlight the value and benefits of supporting a flexible demand response market. As a start the Government Investment in Decarbonising Industry (GIDI) Fund has been one approach to ensure flexibility is built into project designs. Understanding the benefits of flexibility from process heat to offset network investment or to lower connection costs is being explored through this process.

149. The government could also fund and share indicative information about the future value of flexibility for the wholesale market and ancillary and reserve services and ensure these benefits are considered and included in existing workstreams, such as via EECA's 'Energy Transition Accelerator'.[56]

150. There are likely to be significant untapped opportunities for demand response as a firm/dispatchable resource that could avoid higher cost investment in flexible generation or storage. We seek your feedback on whether alternative market measures could be developed to provide more information and certainty for the market.

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55 Contact Energy. (2023, 29 May). *Capital Markets Days 2023 (investor presentation)*. Available at: PowerPoint Presentation (nzx-prod-s7fsd7f98s.s3-website-ap-southeast-2.amazonaws.com)

56 EECA. (2023, June). *Energy transition accelerator.* EECA website. Available at: https://www.eeca.govt.nz/co-funding/energy-transition-accelerator/

### *Distributor and retailer response mechanisms (existing ripple control)*

151. Retailers can use demand response capability to manage load and at times influence spot prices in an area, particularly if that area is constrained. At times a retailer may contract with distributors to use ripple control to provide load shifting services for peak periods.

152. Ripple control is a tool for managing electricity demand and is currently the principal demand response tool used by distributors. Distributors use ripple control to turn off household hot water heating systems at times of peak demand. This has several potential benefits including ensuring demand does not exceed network capacity and can defer expenditure on network upgrades.

153. In New Zealand ripple control has been used for many decades and has helped to improve the utilisation of generation, transmission, and distribution assets. The load connected to ripple control equates to approximately 15 per cent of New Zealand's annual peak demand. However, the proportion of consumers with ripple control is gradually declining due to the removal of ripple relays by retailers/solar installers as well as the increasing uptake of alternate energy sources for water heating.

154. The Authority's Real Time Pricing project dispatch notification product (outlined at paragraph 132 above) will support new technologies with increased functionality. For example, Influx are offering a new service enabling retailers to control discretionary demand such as household hot water heating. Retailers are also trialling new tariffs/plans to make use of the new communications technology available with modern smart meters. Chapter 10 seeks feedback on broader approaches to distributed flexibility.

## FURTHER MEASURES TO CONSIDER?

155. A variety of approaches could be explored to develop New Zealand's demand response market further and to encourage and incentivise more large-scale energy users to participate including:

- providing better and additional information to support investment decisions about incorporating distributed flexibility into new or upgraded energy use infrastructure
- developing measures to enable large consumers to smooth volatile revenues from distributed flexibility to support investment in flexibility
- providing more readily accessible measures for all participants both large scale, distributors and retailers to support demand-side response in future winters.

### *Questions*

| | |
|---|---|
| 15. | What types of commercial arrangements for demand response are you aware of that are working well to support industrial demand response? |
| 16. | What new measures could be developed to encourage large industrial users, distributors and/or retailers to support large-scale flexibility? |
| 17. | Do you have any views on additional mechanisms that could be developed to provide more information and certainty to industry participants? |

# PART 2: COMPETITIVE MARKETS

Part 2, Competitive Markets, considers the competition issues that may arise in the electricity market during the transition away from fossil fuels. Within Part 2:

Chapter 6, **Workable Competitive Electricity Markets**, draws on the Electricity Authority's (Authority's) wholesale market review and the Market Development Advisory Group's (MDAG's) paper on *Price discovery in a renewables-based electricity system*. That work identifies the risk of increased market concentration in dispatchable renewable generation – particularly hydro generation with long term storage – during the transition. This could result in weaker competition, higher prices and/or lower reliability. The Authority and MDAG considered a range of measures to monitor competition, reduce the likelihood and extent of any lessening of competition, and mitigate potential harms if competition is significantly weakened. We consider which measures could be considered back-stop measures. We also seek feedback on whether the government should further consider wider measures to address concerns raised by independent retailers, such as vertical separation, reducing the footprint of larger vertically integrated generator-retailers (gentailers), and/or considering how to ensure independent retailers have access to flexible hedge contracts on terms equivalent to a gentailers' retail arms. We seek feedback on whether government should consider specific measures in more detail.

### *Focus for Part 2 – Competitive markets*

| | |
|---|---|
| CHALLENGES | • Market concentration of providers of dispatchable generation or other flexible resources could increase as the use of fossil fuel generation reduces<br>• Resulting reduction in competition could adversely affect electricity prices and reliability during and after the transition |
| WORK ALREADY UNDERWAY | • The Authority has an ongoing work programme to improve wholesale price discovery and competitive access to flexible services<br>• The Authority is also gathering information to inform its monitoring of competition over time<br>• MDAG has recommended further measures to improve competition |
| FURTHER POSSIBLE MEASURES TO CONSIDER | • Whether or when specific conduct or structural measures should be considered, including horizontal separation of generators with significant market share in flexible hydro storage, vertical separation of gentailers controlling hydro storage, regulated access pricing for flexibility services/contracts provided by generators that control flexible resources, and/or central procurement of new and existing flexible resources |

# 6 Workably competitive electricity markets

156. As fossil fuels are phased out of the electricity system, the evolving generation mix might weaken competition in parts of the market – particularly for firm resources that can balance non-firm resources over periods longer than a few days. The Electricity Authority (Authority) has noted there is a risk that, during extended periods of low hydro inflows or cold weather with low wind and cloud, the market power of stored hydro generation could rise as fossil fuelled generation exits, unless and until alternative flexible generation enters.[57] The Market Development Advisory Group (MDAG) also commented on this risk in its project on wholesale pricing in a renewables-based electricity system.[58]

157. Weaker competition could potentially harm consumers if it raised prices, discouraged generation investment and/or if it limited the ability for retailers to enter and grow their market share.

158. We agree with the Authority's and MDAG's view that our evolving generation mix might increase market concentration in flexible generation resources, which might lessen competition in related products or services over time. However, like the Authority and MDAG, we do not have a definitive view that competition is or will be inadequate, but rather that the potential for weakened competition is a risk that warrants further consideration and monitoring.

*Questions*

| | |
|---|---|
| 18. | Do you agree that the key competition issue in the electricity market is the prospect of increased market concentration in flexible generation, as the role of fossil fuel generation reduces over time? |
| 19. | Aside from increased market concentration of flexible generation, what other competition issues should be considered and why? |
| 20. | What extra measures should or could be used to know whether the wholesale electricity market reflects workable competition, and if necessary, to identify solutions? |

## WHAT IS ALREADY UNDERWAY?

159. The Authority has an active work programme to address these risks to competition, including to:

57 Electricity Authority. (2023, May). *Promoting competition in the wholesale electricity market in the transition toward a renewables-based electricity system: Decision paper*. Page 7.

58 Market Development Advisory Group. (2022, December). *Price discovery in a renewables-based electricity system: options paper*. Paras 10.7-10.16.

- continue proactive monitoring and enforcement of trading conduct in the spot market, and investigate the application of trading conduct rules to the forward market
- investigate mechanisms to accelerate the development of the demand response market
- clarify disclosure requirements about current or expected constraints that could impact generation capacity, and arrange a centralised location for disclosure
- explore better information sharing processes and obligations with the Commerce Commission on any information the Authority collects that may raise concerns about restrictive trade practices, collusion, or misuse of market power
- undertake regular monitoring of progress on generation investments, and an annual update of the investment pipeline and impediments
- regularly collect information on offtake and 'firming' agreements (and if feasible declined requests) to understand and build the evidence base about the nature and scale of current and emerging access issues reported by developers of new generation
- improve the Electricity Hedge Disclosure System to improve its functionality and make contract details more transparent
- investigate and test the case for providing or requiring longer-dated futures
- analyse thermal generation transition risks in the context of demand to 2030, its role in hydro firming and more prevalent solar and wind generation, and options to mitigate transition risks.

160. In its options paper on wholesale pricing in a renewables-based electricity system, MDAG recommended focussing attention on certain conduct measures in the first instance, noting they can be modified over time to reflect changing circumstances and have less risk than structural measures. We note the Authority also considered some of these measures and is progressing some of them. The conduct measures favoured by MDAG included:[59]

- Develop a dashboard of competition indicators for flexibility services – to better assess how competition for flexibility products is changing.
- Improve transparency of hedge market information – to make it easier for participants to compare prices, especially for non-baseload contracts. This would also facilitate surveillance of the contract market to assist in detecting breaches of Part 2 of the *Commerce Act 1986* or trading conduct provisions in the *Electricity Industry Participation Code 2010* (if extended as below).
- Extend existing trading conduct rules to the hedge market – to deter participants from exercising significant market power in the market for flexibility products.

[59] Market Development Advisory Group. (2022, December). *Price discovery in a renewables-based electricity system: options paper*. Paras 10.17 - 10.26. Note that the Authority also considered similar measures and is progressing some of them.

- Develop a flexibility access code (non-price elements) – to promote reasonable access to flexibility products. The code would focus on how participants receive and respond to requests for flexibility contracts, modelled loosely on the code being developed in the supermarket industry to address similar types of concerns regarding access to wholesale supply.
- Introduce market-making for a shaped hedge product, such as some form of cap or peak product – to create better forward price discovery and market liquidity for flexibility services.

161. MDAG cautioned that conduct-based measures might prove insufficient over time, and in that event, structural measures could be warranted and should be investigated.

162. MDAG's preferred structural measure was a 'virtual' disaggregation of long-term storage by allocating (via auction) a tranche of flexible contracts from the primary holders of flexible supply (such as Meridian and Mercury) to other wholesale market participants. Virtual disaggregation could be a form of enforced contracting, under which a contract counterparty would assume a portion of the generator's financial interest/exposure to the wholesale electricity price. Virtual disaggregation would limit a generator's incentive and opportunity to alter the shape (volatility) of the spot price duration curve by reducing the quantity of energy it has that is exposed to the spot price. This measure could take some time to implement, could be difficult to design given the need to account for uncertain hydro inflows, and could potentially discourage investment by the affected generators in the meantime. MDAG did not recommend progressing this structural measure but suggested it could be investigated further in order to have a backstop ready to go quickly in the event conduct measures prove inadequate.

## FURTHER MEASURES TO CONSIDER?

163. MDAG considered a wide range of measures to maintain or strengthen competition in the face of potentially increasing market concentration of flexible generation resources. The section above summarises the measures initially preferred by MDAG and in this section we summarise the measures not initially preferred – either because those measures would not effectively deal with the competition issues or because they could have harmful side-effects or risks.

### *Conduct measures not initially preferred by MDAG*

164. The conduct measures not initially preferred by MDAG, with MDAG's reasoning being as follows:

- Minimum level of forward contracting or offers – generators with substantial market power would be required to offer additional contracts for sale if actual contract sales were below a minimum level. While forward contracting can reduce incentives to exercise market power in spot market, there would be no mechanism to ensure that contracts being offered are available on reasonable terms. An obligation to contract could unintentionally undermine incentives for obliged participants to invest.
- Spot market price cap – a formal price cap would apply in the spot market. This would be unlikely to address the principal issue, which this the scope of hydro

generators with significant storage to alter the shape of the price duration curve (rather than just the maximum spot price). Depending on its level, a spot price cap could suppress incentives for efficient demand response, use of storage, forward contracting, and investment.

- Selective offer price cap – generators with substantial market power would be subject to a cap on their offer prices. This approach is used in parts of the US. It assumes that high spot prices (where efficient) can only emerge if a smaller player (generation, battery or demand response) not subject to the offer cap offers its capacity at a high price. That may not be realistic given the relatively small size of the New Zealand market, especially in periods/regions where supply is tight on a transitory basis. It might also be difficult to implement in practice.
- Contract price cap – generators with substantial market power would be subject to a cap on prices in their contracts. Relevant generators could be deterred from manipulating spot prices if wholesale buyers could purchase contracts at capped prices. However, it would be hard to set correct price, especially for critical shaped hedge products. As with a spot price cap, setting the cap too low would suppress incentives for efficient demand response, use of storage, and investment.

### *Structural measures not initially preferred by MDAG*

165. The structural measures not initially preferred by MDAG, with MDAG's reasoning, were:

- Ringfencing – generators with substantial market power would be required to undertake generation investments in a ring-fenced entity. The treatment of ringfenced affiliates could provide a reference point for assessing major generators contracting interactions with independent generation/developers. However, there may not be any useful transfer price data produced by a ringfence. A ringfence obligation could undermine incentives for affected generators to invest in new generation.
- Virtual asset swaps – extend the existing 15-year basis swap arrangements between Meridian Energy and Genesis and Mercury (which expire in 2023). These are locational baseload swaps and therefore unlikely to have any material effect on incentives to alter the shape of spot prices.
- Physical break-up of generation capacity – some hydro generation capacity (especially Mercury and Meridian) would be reassigned via sale (including dispatch rights). There are limited options available unless disaggregation of stations on single river chains are considered. Disaggregation of stations on single river chains would likely reduce coordination efficiency, and would not address the key issue, which is the concentration of rights to longer term storage in the reservoirs at the head of each river chain. Any enforced asset sales are disruptive and could delay or deter investment by affected generators.

### *Vertical integration and access to flexible hedge contracts*

166. Vertical separation and/or regulated access to flexible hedge contracts is advocated by some independent retailers to limit generator market power being leveraged into the retail market

by vertically integrated gentailers, resulting in reduced retail competition and higher costs for consumers.

167. MDAG considered that vertical separation would not address the primary competition issue. The Authority included vertical integration as an indicator in its analysis of wholesale market competition but did not specifically analyse the impact of vertical integration on the retail market. Having said that, MDAG and the Authority recognised that vertical integration between generation and retail businesses has the potential to limit liquidity in the contracts needed to manage price risk, and they considered a range of measures to improve contract market liquidity and price discovery, including a flexibility access code (non-price elements) and market-making for shaped hedge products (peak or cap products). The Authority also has projects underway to gather and investigate evidence of market power affecting retail competition, including monitoring of retailer gross margins and disclosure of internal transfer prices by vertically integrated gentailers. This was a recommendation from the 2018-2019 Electricity Price Review (EPR).[60]

168. The EPR considered whether vertical integration limits competition across the supply chain. It considered that forced separation would substantially change New Zealand's electricity market and disrupt many businesses. The EPR suggested that this change would be unnecessary because other measures to improve the contract market would counter the drawbacks of vertical integration at much lower cost and risk while retaining the benefits of integration. The EPR also noted that more far-reaching measures, such as vertical separation, might be warranted if its recommended measures (like mandatory market making) did not produce the desired results.

169. The Authority responded to the EPR's recommendations on enhancing the hedge market, including by introducing commercial market-making services and a back-stop regulatory obligation on certain gentailers if they fail to meet market-making performance standards (including a maximum spread between bid and offer prices of 3 per cent). However, some independent retailers continue to say that access to hedges (particularly shaped hedge products) is limited, which hampers their ability to compete effectively in the retail market.[61]

170. Figure 5 below, from a Concept Consulting report for the Authority,[62] shows the greater divergence in wholesale contract price above estimated long run marginal cost of generation (LRMC) of baseload supply. Whilst the LRMC may have risen since this analysis was published in July 2022, we understand a substantial margin may still remain.

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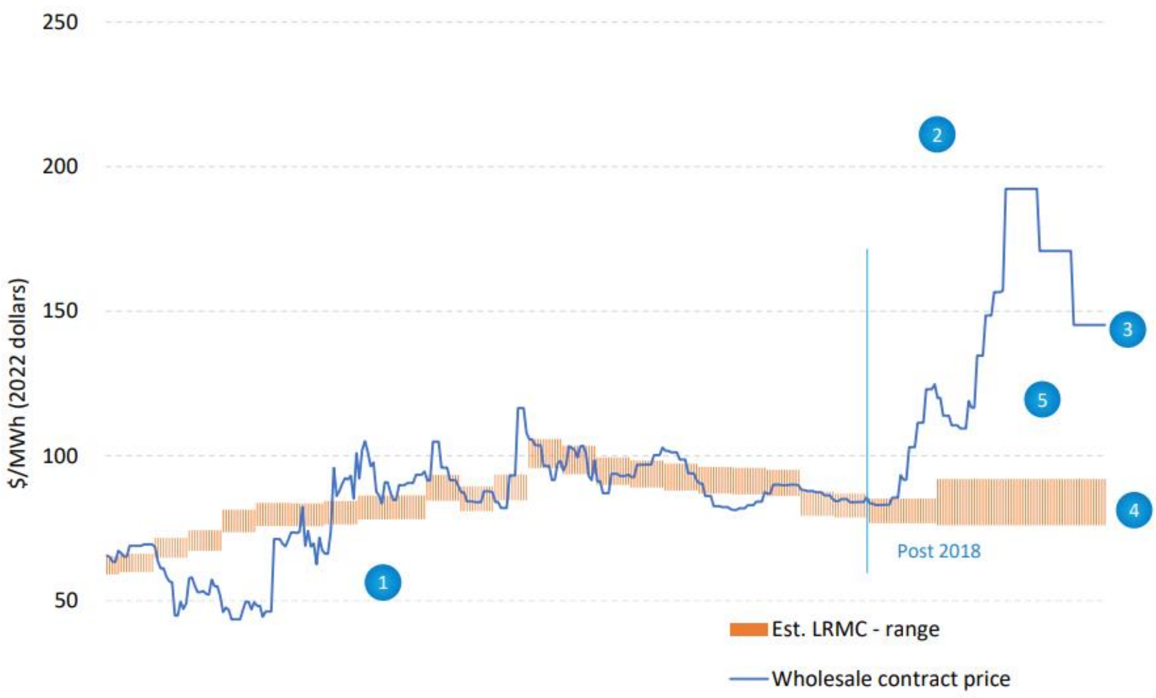
60 See MBIE. (2023, June). *2018 – 2019 Electricity Price Review*. MBIE website. Available at: [2018-2019 Electricity Price Review | Ministry of Business, Innovation & Employment (mbie.govt.nz)]

61 2degrees, Electric Kiwi, Flick, Haast Energy, and Pulse Energy. (2023, 3 March). *Submission on MDAG Price discovery in a renewables-based electricity system options paper.* Available at: https://www.ea.govt.nz/documents/2519/Haast__Independent_retailers_-_MDAG_submission_-_100RE_Options_-_2023_03_03_FINAL.pdf

62 Electricity Authority and Concept Consulting. (2022, July). *Generation investment survey 2022*.

*Figure 5: Contract prices and estimated costs for new baseload supply*




Notes:

- Pre-2019 data is from *Electricity Price Review Technical Paper* – see [www.mbie.govt.nz/dmsdocument/4334-electricity-price-review-first-report-technical-paper](www.mbie.govt.nz/dmsdocument/4334-electricity-price-review-first-report-technical-paper).
- Contract prices post 2019 are from electricity futures contracts quoted on ASX. They are deflated using CPI, with assumed inflation of 2% for future years.
- Estimated costs for new baseload supply post-2019 are derived by Concept from multiple sources.

Key points made by Concept (relating to numbers on Figure 5):

1. Until 2018 contract prices tracked relatively closely to the estimated cost of new baseload supply (albeit with fluctuations at times).
2. Since 2019, contract prices have been significantly above the estimated cost of new supply.
3. While forward contract prices for 2023- 2025 are trending downwards, they are still well above the estimated cost of new supply.
4. The new supply cost range is an estimate. The range on the chart has widened post-2020 to reflect:
    - Increased uncertainty about costs of plant (wind turbines and solar) in the next few years due to supply chain disruption
    - Increased uncertainty about construction costs in the next few years due to tight markets for contractors and specialized equipment such as high lift cranes
    - Increased uncertainty about the cost of firming intermittent renewable generation.
5. Notwithstanding the uncertainty about the estimates, it is clear that contract prices exceed longer-run costs of new supply.

171. The Authority's analysis of 2022 retail gross margins found that the cost breakdowns of gentailers and retailers without a generation portfolio were similar, suggesting a competitive market. However, high spot and hedge prices compared to previous years meant that new

entrants to the retail market likely struggled to compete with incumbents in 2022.[63] The Authority compared the internal transfer prices (ITPs) disclosed by five vertically integrated gentailers with benchmark ITPs representing a range of plausible retailer hedging strategies. This comparative analysis suggests that the disclosed ITPs for each year between 2018 and 2022 were broadly consistent with the benchmarks selected, although we note that the range of benchmark ITPs appears large relative to the retail gross margins needed for a retailer to be competitive. This makes any definitive conclusion about retail competition difficult.[64]

172. The Authority's comparative assessments of retailer gross margins and ITPs may not provide definitive assurance that retail market competition is workable or effective, but over time they are expected to help build confidence in the market by reducing information asymmetry and improve trust. Alternatively, regular assessments over time might indicate whether or when further measures are warranted to strengthen retail competition.

173. The Authority's ongoing efforts to promote retail competition will include considering MDAG's proposals to improve wholesale price discovery, contract liquidity, and access to flexibility contracts. A flexibility access code of the kind recommended by MDAG (and under development separately in the supermarket sector) is close to one end of a spectrum of potential forms of access regulation. Closer to the other end of the spectrum is regulated access pricing, which applies to some wholesale telecommunications services in New Zealand.[65]

174. Like vertical separation, regulated access pricing would be a significant intervention if applied to flexibility contracts. Regulated access pricing for flexibility contracts would need careful consideration to avoid or mitigate the risk of undermining incentives for investment in flexible services by regulated providers.

175. We are interested in views on whether, and if so what, additional measures may be warranted to address the retail market issues raised by independent retailers.

### *Questions*

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|---|---|
| 21. | Should structural changes be looked at now to address competition issues, in case they are needed with urgency if conduct measures prove inadequate? |
| 22. | Is there a case for either vertical separation measures (generation from retail) or horizontal market separation measures (amending the geographic footprint of any gentailer) and, if so, what is this? |

63 Electricity Authority. (2023, 12 May). *NZ's electricity retail market: retail gross margins.* Electricity Authority website. Available at: https://www.ea.govt.nz/news/general-news/new-zealands-electricity-retail-market-retail-gross-margins/

64 Electricity Authority. (2023, April). *ITP benchmarks: Compare participant's disclosed internal transfer prices with benchmarks*. Available at: https://public.tableau.com/app/profile/electricity.authority/viz/ITPbenchmarks/ITPbenchmarks

65 Commerce Commission. (2023, June). *Regulated services*. Commerce Commission website. Available at: https://comcom.govt.nz/regulated-industries/telecommunications/regulated-services

| | |
|---|---|
| 23. | Are measures needed to improve liquidity in contract markets and/or to limit generator market power being used in retail markets? If yes, what measures do you have in mind, and what would be the costs and benefits? |
| 24. | Should an access pricing regime be looked at more closely to improve retail competition (beyond the flexibility access code proposed by the Market Development Advisory Group or MDAG)? |
| 25. | What extra measures around electricity market competition, if any, do you think the government should explore or develop? |

### *Facilitating new investment and new entry*

176. MDAG also considered a structural measure labelled 'central procurement of flexible resources', as a measure to increase new entry and reduce market concentration in those resources. In this measure, new flexibility sources (storage, demand response, or flexible generation) could be procured or underwritten via central support mechanism such as long-term contracts with costs recovered via levy.[66]

177. Central procurement of flexible resources could be like some of the measures discussed in Part 1. They could also be like measures being investigated in the NZ Battery Project. Although the focus of the NZ Battery Project is on large-scale long-term flexibility investments that can materially reduce the dry year problem, some technologies to achieve this – including large pumped hydro – can provide significant short-term flexibility too. That aside, a central procurement measure could cover both firm and non-firm resources, and it could potentially extend to all such resources, whether new or existing. This latter form may be called a 'single buyer model' and, is described at a very high level below.

### *Single Buyer Model*

178. A single buyer market is one where a central agency operates the wholesale market, buying electricity from generators and supplying electricity to retailers (who on-sell to consumers). There is competition on the supply side for investment in generation, in the form of contestable tenders run by the central buyer. The central buyer may also determine how generation is used (dispatched) based on its own information about plant availability, operating costs, hydro inflows and storage levels, transmission outages, etc, which could address any market power held by generators if they were free to determine their own dispatch offers. A potential drawback of the single buyer model is that it limits diversity and plurality of views about risk and approaches to risk management. On the other hand, a single buyer could potentially realise coordination efficiencies through more integrated planning of generation and transmission investments.

179. A single buyer model also provides an opportunity to adopt a different approach to wholesale electricity pricing, if there were a desire to do so. A single buyer could choose to sell the electricity it purchases from generators at a long-run average price that varies slowly over time and is the same in every part of the country. In contrast, the current market model

66 We understand that MDAG did not assess this option further because it is in the purview of the NZ Battery Project.

generally produces prices that vary significantly on a locational basis and through time, reflecting that it costs more to deliver electricity to some places, and at certain times, relative to other places and times.

180. Absent significant market power, wholesale spot pricing in the current model provides relatively efficient signals for the short-term use of resources (eg, hydro storage and demand response) and wholesale contract prices (or expectations of future spot prices) provide relatively efficient signals for investment. In contrast, the efficiency of spot electricity prices and transmission prices in a central buyer model is less important, because it is the central buyer, not market participants, who decides on generation and transmission investment. A single buyer might employ average cost pricing if the associated distributional impacts were considered more important than the loss of investment and operational efficiency. We note that distributional objectives can also be pursued, and more effectively targeted, through measures outside of electricity market pricing, for example through income support and other social welfare measures.

181. Establishing a single buyer model in New Zealand could be considered an extreme measure relative to the measures considered by MDAG. It would have even more significant design and implementation complexity than the structural options discussed above, and the transition from the current model could take some time during which investment in new generation could pause. It is listed here for completeness, and we welcome views on its pros and cons.

### *Question*

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| 26. | Do you think a single buyer model for the wholesale electricity market should be looked at further? If so, why? If not, why not? |

# PART 3: NETWORKS FOR THE FUTURE

Part 3, **Networks for the Future,** considers how we ensure sufficient transmission and distribution network 8989xinvestment to support new renewable electricity and electrification. It seeks feedback on whether regulatory settings are sufficiently agile in a world where significant new investment and new network connections are required to support electricity system transition. In this Part we note the Electricity Authority's (Authority's) and Commerce Commission's (Commission's) significant regulatory workstreams and seek feedback on areas for further government focus to support a secure, reliable energy transition and deliver affordability for consumers.

Chapter 7 **A transmission system for growth** is about ensuring sufficient transmission investment for renewable electricity and electrification. It seeks feedback on how to ensure regulatory systems are fit for purpose to enable necessary transmission investments, as well as whether any further actions or steps are needed to support a resilient national grid.

Chapter 8 **Distribution networks for growth** focuses on ensuring sufficient distribution system investment and reducing distribution system barriers to support electrification. It seeks feedback on whether any additional measures are needed to address challenges relating to connection of new demand, such as industrial load or EV chargers. It also seeks feedback on whether alternative approaches should be considered in relation to how costs are allocated to support network investment ahead of immediate need, as well as whether distribution pricing signals are sufficient to support efficient use of networks.

Chapter 9 **Is the government's sustainability objective adequately reflected for market regulators** seeks feedback on whether the government's policy objectives are adequately reflected for our electricity system regulators. It also asks whether any additional direction would help to align the regulators' own decision-making frameworks with government's policy objectives.

*Focus for Part 3 – Networks for the Future*

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| **CHALLENGES** | • Whether any further actions or steps are required to ensure there is sufficient focus and investment on ensuring a resilient transmission system<br>• What approaches might be needed to ensure sufficient investment in distribution assets for an expanded and more highly renewable electricity system<br>• Whether models for recovering and allocating costs for distribution system connections are appropriate for the transition<br>• Whether there is a need for either 'renewable energy zones' at a distribution system level, or another regional energy planning approach<br>• Whether objectives set for the system's regulators may be too rigid to accommodate new policy priorities such as decarbonisation |
| **WORK ALREADY UNDERWAY** | • The Commission's 2023 Input Methodologies Review, targeted information disclosure review and default price-quality path resets<br>• The Authority's regulatory workstreams on distribution networks settings, distribution pricing and connections processes<br>• The Commission and the Authority have explicitly considered how government policy objectives such as decarbonisation can be taken into account in their decision-making and balanced against their statutory objectives |
| **FURTHER POSSIBLE MEASURES** | • Support for co-ordinated generation and transmission investment via Renewable Energy Zones |

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| **TO CONSIDER** | • Optimising local planning to maximise benefits for consumers through distribution level Renewable Energy Zone or alternative bottom-up regional system planning<br>• Supporting development of a regulatory system for investment in transmission and distribution, that provides for decarbonisation, including whether regulator objectives includes decarbonisation |

# 7 A transmission system for growth

182. New Zealand's electricity transmission network is owned and operated by the state-owned enterprise Transpower.[67] Under the *Electricity Industry Act 2010*, Transpower is also the designated System Operator, tasked with ensuring the real-time co-ordination of the electricity system, providing information and short to medium-term forecasting on all aspects of supply security, and managing supply emergencies.

183. Following a few decades of relatively flat electricity demand growth, we are moving into a period of greater transmission investment need for generation and electrification. In New Zealand renewable resource rich areas (sunny or windy areas) can often be far away from areas of higher electricity demand ('load centres'). This means transmission investment is required to connect renewable generation into the grid and transport the electricity to where it will be used.

184. To illustrate the size of the challenge, Transpower has estimated that by 2035, it will require:[68]

- 40 new grid connected generation and grid-scale battery projects
- 30 connections to accommodate increased electricity demand (load connections)
- 10-15 new transmission interconnections and other network investments needed to enable energy to reach consumers.

185. We are already beginning to see this energy transition take place when looking at Transpower's connection enquiries. Over the past three years, there has been a significant increase in the volume of enquiries from potential developers of new generation, and increasingly more enquiries from load customers. The 2021/2022 financial year saw a total of 124 enquiries (9 demand / 115 generation) – around double the previous year and up from 5 total enquiries in 2018/2019. As of July 2023, Transpower has 348 connection enquiries in its connection query pipeline.[69]

186. Transmission constraints have also been identified as a barrier in other countries' electrification and decarbonisation journeys.[70]

### *We are seeing increased investment signalled by Transpower to support electrification and connect new renewables*

187. Transpower's Net Zero Grid Pathways (NZGP) project is a multi-year programme of work through which Transpower will investigate, plan, consult on and seek investment approval for large projects to help New Zealand meet its climate change objectives through

[67] A map of New Zealand's transmission network is available here: https://www.transpower.co.nz/our-work/industry/our-grid/maps-and-gis-data

[68] Transpower. (2020, March). *Whakamana i Te Mauri Hiko: Empowering our Energy Future*.

[69] A map of connection queries by region is available here: https://experience.arcgis.com/experience/97d4604079b545448280423f9269b9ea/page/Dashboard/

[70] For example, see Alex Lawson. (2023, 16 May). Gird Connection delays for low-carbon projects 'unacceptable', says Ofgem. *The Guardian*. Available at: https://www.theguardian.com/business/2023/may/16/grid-connection-delays-low-carbon-projects-ofgem-energy

electrification of the economy. NZGP is the enabling work on the national grid to ensure that when new generation is ready to be connected, the grid can take the additional electricity and transport it to where it's needed.

188. Transpower recently submitted a major capital proposal (MCP) to the Commerce Commission (Commission) for its 'Net Zero Grid Pathways Stage 1' project which totals approximately $400 million with three major proposed investments to enhance capacity of the core national grid (upgrading the HVDC inter-island link, Wairakei Ring and Central North Island).

189. Transpower is currently preparing its five-year plan for expenditure and quality of service for 2025-2030, known as Regulatory Control Period 4 (RCP4). This plan will propose a significant increase in investment expenditure which Transpower believes will support a reliable national grid and facilitate the growth and electrification of the economy. To illustrate this, key changes proposed for RCP4 plan (compared to RCP3) include a 44 per cent increase in base capital expenditure, and a 17 per cent increase in operating expenditure.

### *Regulatory systems that enable necessary investments*

190. There is a need to ensure that the regulatory system for approvals of new transmission investments is fit for purpose, within the context of the energy transition and changing demands on the transmission system. This is particularly the case given long lead times for transmission investment.

191. A key challenge is to ensure regulation enables sufficient investment where current and future demand exists, while managing the risks of over-investment where there is insufficient demand. There is a visible cost to insufficient capacity in the form of rationing (potentially leading to high wholesale electricity prices) and outages. On the other hand, there is also a cost to spare capacity, which leads to higher costs for consumers.

192. In an environment of increasing electricity demand, the balance of risk between under- and over-investment may have shifted compared to previous decades. The risks and the consequences of under-investment are now higher than before, due to our need to decarbonise the economy. If a project is delivered ahead of time, customers will pay for the lost time value associated with the project. However, a project that comes online too late could delay electrification or investment in new generation, which in turn could have a significant impact on wholesale prices or emissions reductions.

193. We understand that it takes Transpower up to 7-10 years to build new transmission assets when taking into account the time required for planning, consenting, land access agreements, regulatory approvals and construction build. Long timeframes for new transmission investment can slow or hold up electrification or new renewable generation projects, risking delays in decarbonisation. Investing in the network ahead of time can encourage renewable generation and electrification. The business case for electrification may be stronger with transmission infrastructure already in place.

### *Consenting also provides a challenge to timely transmission infrastructure*

194. As mentioned in Chapter 2, resource management consenting issues are outside the scope of this document. MBIE and the Ministry for the Environment recently consulted on the

*National Policy Statement for Renewable Electricity Generation* (NPS-REG) and *National Policy Statement for Electricity Transmission* (NPS-ET). A discussion paper seeking feedback on issues relating to transmission investment can be found at on MBIE's website.[71]

### *Question*

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| 27. | Do you consider that the balance of risks between investing too late and too early in electricity transmission may have changed, compared to historically? If so, why? |

## A FIT FOR PURPOSE REGULATORY FRAMEWORK FOR TRANSMISSION INVESTMENT

### *Background of regulatory system – Part 4 Commerce Act 1986*

195. Transmission is a monopoly service as consumers generally have no choice over the provider of the lines over which their electricity is delivered (and must legally pay Transpower for these services). To ensure that monopoly transmission services are provided in a fair and efficient manner, the Commission regulates and scrutinises Transpower's revenue and performance, including for investments Transpower makes into the national grid under Part 4 of the *Commerce Act 1986*.

196. Part 4 of the *Commerce Act 1986* regulates price and quality of goods or services in markets where there is little or no competition. Sectors regulated under in Part 4 include electricity lines services, gas pipeline services and specified airport services. The components of the regulation under Part 4 specific to Transpower are set out below:

- Input methodologies (IMs) – IMs set the rules, requirements, and processes for services regulated under Part 4, including transmission services, to provide certainty for regulation under Part 4. They prescribe methodologies for asset valuation, cost allocation, risk allocation, and financial return settings. IMs are required to be reviewed every seven years and are currently under review for Transpower and distribution businesses.
- Yearly disclosure of information is required on Transpower's performance – price-quality regulation sets revenue limits and quality standards for Transpower's services. A price-quality path is reset every five years. The latest price-quality path for Transpower was set in 2019 for the period April 2020 to March 2025. Transpower is currently preparing its five-year plan for expenditure and quality of service for 2025-2030, known as RCP4.[72]
- Assessment and approval processes for certain capital investment proposals additional to base price-quality expenditure (including the 'investment test')[73] – this is described in more detail in Box 5 below.

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71 MBIE. (2023, June). *Consenting improvements for renewable electricity generation and transmission*. MBIE website.

72 Transpower. (2023, June). *Regulatory Control Period (RCP4) consultation.* Transpower website. Available at: https://www.transpower.co.nz/our-work/industry/regulation/rcp4

73 Commerce Commission. (2020, 29 January). *Transpower Capital Expenditure Input Methodology Determination 2012*. See Schedule D. Available at: https://comcom.govt.nz/__data/assets/pdf_file/0026/88280/Transpower-capital-expenditure-input-methodology-determination-consolidated-29-January-2020.pdf

| Box 5: Transpower's capital expenditure (capex) IM investment test |
|---|

Major investments in transmission that are expected to cost over $20 million must be individually approved by the Commission using criteria set out in Transpower's capex IM.

The Commission applies its 'investment test', in determining whether to approve significant transmission upgrades. An investment option satisfies the investment test if it meets all of the following:

- it has the highest expected net electricity market benefit compared to other investment options
- it has a positive expected net electricity market benefit, unless it is designed to meet an investment need the satisfaction of which is necessary to meet the deterministic limb of the grid reliability standard
- it is sufficiently robust under sensitivity analysis.

The investment test process aims to ensure efficient transmission investment in the long-term interests of consumers through external regulatory scrutiny of investment proposals and opportunities for stakeholders (who will ultimately pay for these assets) to provide input. The investment test requires the use of demand and generation scenarios produced by MBIE.

The investment test process includes the consideration of whether non-transmission solutions are economically and technically feasible to avoid or defer an investment into the national grid.

Along with other processes including RMA consenting, negotiating land access and managing supply chains, the investment test can influence the speed with which Transpower is able to make major grid investments, as well as what major grid investments may ultimately be approved.

## WHAT IS ALREADY UNDERWAY?

197. As part of the 2023 Input Methodologies Review (IM Review), the Commission is reviewing Transpower's capital expenditure IM, which sets out the rules for Transpower proposing, and the Commission assessing, Transpower's major capital expenditure proposals. The powers to review and amend the IMs must be used to promote the objectives of Part 4 of the Act.[74]

198. MBIE considers that the Commission's IM Review is the appropriate vehicle to consider whether the investment test for investments costing over $20 million is fit for purpose as those rules fall within capital expenditure IM. For example, Transpower has submitted on the IM Review that:

> …a strict market benefit test may not be flexible enough to take into account wider NZ Inc benefits such as Government climate change policy and CO2 emissions, even if these benefits align with the long-term benefit of consumers.

199. In June 2023, the Commission published draft decisions on the IM Review, including those that apply to Transpower. Consultation on the IM Review draft decisions closes in early August 2023, with final decisions due in December 2023. As previously mentioned, the Commission will also undertake a reset of Transpower's individual price-quality path (RCP4) in 2024.

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[74] Commerce Commission. (2023, 14 June). *2023 Input Methodologies Review.* Commerce Commission website.

200. The Commission has indicated how they have considered issues raised by stakeholders in their draft decisions on the IM Review (including some issues related to Transpower's capex IM), provided a view on whether issues raised are genuine barriers or not, and proposed solutions. Some of the proposed solutions will involve changes to the IMs and others will fall under Transpower's individual price-quality path reset process.

## ENSURING GRID RESILIENCE FOR THE FUTURE

201. An electrified future will increase New Zealand's dependence on a resilient national grid for uninterrupted, reliable electricity supply. Electrification will be key to decarbonise our energy systems to achieve climate change objectives. However, natural disasters, such as earthquakes, and climate-related extreme weather events are already challenging the resilience of electricity supply infrastructure. This could undermine energy security if resilience is not managed appropriately. Increasing the resilience of key grid assets (such as the HVDC cable) where there is a concentration of risk will be important in future. Many parties have noted that improving grid resilience has become increasingly urgent.[75]

202. Resilience is more than the durability of the network and the ability to withstand extreme weather events or other external shocks. It includes the ability to evolve and adapt in the face of a changing risk profile – which may require the relocation of existing assets. Resilience is also not confined to physical risks but includes resilience to cyber and foreign interference threats.

203. Investing in a more resilient national grid comes at a cost and can impact affordability. Currently, transmission pricing is approximately 8 per cent of a consumer's bill. This is expected to increase to approximately 10 per cent in the period between 2025-2030, based on Transpower's draft RCP4 submission.

## WHAT IS ALREADY UNDERWAY?

### *New Zealand's first National Adaptation Plan*

204. The Government released New Zealand's first 'National Adaptation Plan' (NAP) in August 2022. The NAP considers the impacts of climate change, and it sets out how we will adapt.[76] The NAP has a specific action for Transpower as well as actions for the Commission which regulates price-quality paths for regulated electricity (and gas) networks.

[75] See International Energy Agency. (2021). *Climate Resilience: Electricity Security 2021*. Available at: https://iea.blob.core.windows.net/assets/62c056f7-deed-4e3a-9a1f-a3ca8cc83813/Climate_Resilience.pdf
See also Climate Change Commission. (2023, April). *2023 Draft advice to inform the strategic direction of the Government's second emissions reduction plan*. Chapter 9. Available at: https://www.climatecommission.govt.nz/public/Advice-to-govt-docs/ERP2/draft-erp2/CCC4940_Draft-ERP-Advice-2023-P02-V02-web.pdf

[76] Ministry for the Environment. (2022, August). *Urutau, ka taurikura: Kia tū pakari a Aotearoa i ngā huringa āhuarangi, Adapt and thrive: Building a climate-resilient New Zealand – New Zealand's first national adaptation plan*. Available at: https://environment.govt.nz/assets/publications/climate-change/MFE-AoG-20664-GF-National-Adaptation-Plan-2022-WEB.pdf

| Box 6: Actions in the National Adaptation Plan relevant to transmission network resilience |
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**Action 3.18: Review electricity and gas networks' management of climate risk and resilience**

Timeframe: Years 1–6 (2022–28)
Lead agency: Commerce Commission
Relevant portfolio: Commerce and Consumer Affairs
Primarily supports: Objective INF3 (Use renewal programmes to improve adaptive capacity)
Status: Current

The Commerce Commission reviews many of the aspects of regulated electricity and gas networks' performance. The Commission is currently consulting on amending the asset management plan requirements for electricity distributors so that sector stakeholders can better understand distributors' risk management, including managing network resilience challenges posed by climate change. From time to time, the Commission will publish reviews of aspects of regulated networks' plans, to support them to improve their approach to managing risk and building adaptive capacity, and to provide more confidence that their related expenditure forecasts are robust.

**Action 5.10: Develop and implement the Transpower Adaptation Plan**

Timeframe: Years 1–5 (2022–27)
Lead agency: Transpower
Relevant portfolio: Energy and Resources
Primarily supports: Objective INF3 (Use renewal programmes to improve adaptive capacity)
Status: Current

The Transpower Adaptation Plan will outline how Transpower will adapt to climate change through the design, delivery and operation of the national grid. It will address exposed assets and new investment in infrastructure, and consider adaptation in maintenance and development programmes.

Transpower will consider multiple risks to the national grid from climate hazards, including coastal inundation, increased frequency of high-impact flood and wind events, and accelerated erosion.

**Action 8.4: Provide for regulated network revenues to reflect the prudent and efficient costs of resilience**

Timeframe: Years 1–6 (2022–28)
Lead agency: Commerce Commission
Relevant portfolio: Commerce and Consumer Affairs
Primarily supports: Objective INF1 (Reduce the vulnerability of assets exposed to climate change)
Status: Current

In the Commerce Commission's next reviews of regulated price-quality paths – from 2025 for electricity networks and from 2026 for gas networks – it will consider the extent to which revenue limits should provide for different expenditure levels from the current period. This will include if expenditure levels need to change due to any increased costs of resilience to climate change, where these are based on robust forecasts. Regulated suppliers can also apply for changes to their revenue limits to better meet their particular circumstances, which could potentially include the prudent and efficient costs of resilience initiatives.

### *New Zealand Infrastructure Strategy, Action Plan and National Resilience Plan*

205. In June 2022, Te Waihanga/Infrastructure Commission published *Rautaki Hanganga o Aotearoa – New Zealand Infrastructure Strategy 2022–2052* which sets out the infrastructure challenges and opportunities facing New Zealand over the next 30 years. As part of Budget 2023 announcements, the Government released *He Whakakaupapa mō Te Hanganga o Aotearoa: The Infrastructure Action Plan* which sets out what it is doing and will do in response to the strategy.

206. The *Infrastructure Action Plan* highlights that the Department of Prime Minister and Cabinet (DPMC) will lead work to enhance the resilience of Aotearoa New Zealand's critical infrastructure. DPMC is undertaking public consultation in 2023 on the adequacy of New Zealand's current regulatory approach to delivering resilient critical infrastructure and make decisions on next steps in 2024.

207. Budget 2023 also set aside $6 billion for strategic investments as part of a new 'National Resilience Plan'. The first 1-5 years of the National Resilience Plan will focus on investing in the resilience of New Zealand's critical infrastructure, as well as the response to recent North Island weather events (such as Cyclone Gabrielle and flooding in Auckland). The initial focus of investments will be road, rail, and local infrastructure reinstatement and telecommunications and electricity transmission investment.

### *Transpower's resiliency-focused work*

208. Transpower's RCP4 submission will propose a significant increase in investment expenditure compared to RCP3. Transpower considers this will support a reliable national grid that will facilitate the growth and electrification of the economy.

209. Transpower's roughly $4 billion planned spend over 2025-2030 will focus on ensuring a reliable and safe transmission network. Transpower primarily provides a resilient network through building back better, when it needs to replace or refurbish assets, to make sure they meet the latest standards.

210. Transpower has also proposed $109 million specifically for resilience investments to reduce the risk of extended outages for customers from major hazards as well as readiness for recovery. This $109 million is over and above the incremental improvements in resilience built into Transpower's regular network strengthening and maintenance work.

211. In addition, Transpower publishes a range of documents which assesses risks to the national grid and how it manages its assets, including its:

- *Asset Management Plan 2022*[77]

[77] Transpower. (2022, September). *Asset Management Plan 2022*. Available at: https://tpow-corp-production.s3.ap-southeast-2.amazonaws.com/public/uncontrolled_docs/2022%20Asset%20Management%20Plan.pdf?VersionId=2PcEJ_GyHfe.G4q6Y_IjEGvaBfX09.rg

- *Asset Health and Network Risk Roadmap*[78]*,* and the November 2022 update to this *Roadmap*.[79]

### *Other relevant resilience focussed workstreams*

212. The Electricity Authority's (Authority's) Future Security and Resilience Project is, in conjunction with the System Operator, looking at how to ensure the electricity system remains secure and resilient in the coming decades. A changing electricity mix through the integration of more renewable, intermittent energy (such as wind and solar) is driving the need to ensure operational security and longer-term system adequacy. The project is focussed on how the power system operates in real-time or close to real-time. A roadmap for this project has been produced and work is ongoing.[80] The Authority has also recently published a set of indicators to monitor changes to the opportunities and challenges to the future security and resilience of the power system, as they may materialise.[81]

## FURTHER MEASURES TO CONSIDER?

213. MBIE has not considered any further potential actions at this stage. However, we are interested in any feedback you have on this emerging issue.

### *Question*

| | |
|---|---|
| 28. | Are there any additional actions needed to ensure enough focus and investment on maintaining a resilient national grid? |

78 Transpower. (2020, November). *Asset Health and Network Risk Roadmap*. Available at: https://tpow-corp-production.s3.ap-southeast-2.amazonaws.com/public/uncontrolled_docs/AHNR%20Development%20Roadmap%2024%20Nov%202020.pdf?VersionId=_ph4zEr8X3AMhV3U.jCHOKwFrkZU4L6U

79 Transpower. (2020, November). *Asset Health and Network Risk Progress Update*. Available at: https://tpow-corp-production.s3.ap-southeast-2.amazonaws.com/public/uncontrolled_docs/s53ZD_AssetHealthNetworkRisk_Progress%20Update_25Nov2022.pdf?VersionId=leWB63UROabBQJOdI71m3kT.VibCva7P

80 Electricity Authority. (2022, 18 August). *Future security and resilience: Implementing activities for a secure and resilient low-emissions power system (final roadmap)*. Available at: https://www.ea.govt.nz/documents/1980/Covering-Paper-FSR-Final-Roadmap-and-Phase-Three.pdf

81 Electricity Authority (2023, June). *Future security and resilience indicators: Monitoring changes to the opportunities and challenges to future security and resilience*. Available at: https://public.tableau.com/app/profile/electricity.authority/viz/Futuresecurityandresilienceindicators/Futuresecurityandresilienceindicators

# 8 Distribution networks for growth

214. Electricity distribution networks are the local lines networks that provide low-voltage electricity to end consumers. New Zealand's distribution network infrastructure is owned and operated by 29 lines companies that are often referred to as electricity distribution businesses.[82] These distribution businesses connect to the national grid and distribute electricity to consumers from the grid through their local networks.

215. Following a period of flat demand growth, greater distribution investment will be required to support renewable electricity generation and electrification. Boston Consulting Group's (BCG's) *The Future is Electric* roadmap estimates that $22 billion is required in distribution sector investment in the 2020s to enable electrification and integrate distributed energy resources (DER).[83]

216. As well as investing in physical lines and poles, greater demand management pressures will mean that distribution businesses will need to invest in monitoring, data procurement and system management. Distribution businesses will also need greater access to data from meters and other smart devices in homes to manage demand. There are also opportunities to use distributed flexibility to offset distribution network investment. Issues and opportunities related to distributed flexibility are discussed further in Chapter 10.

217. The number of requests for new or expanded distribution network connections is already increasing. These requests will need to be prioritised and processed quickly to avoid creating a barrier to the roll out of public EV charging infrastructure, electrification of process heat and distributed generation.

218. We have identified four areas where stakeholders have raised concerns about possible gaps in the regulatory environment:

- Network investment model to support energy transition – the regulatory environment for network investment does not currently provide adequate flexibility to respond quickly to changing circumstances.[84] The regulatory system currently does not sufficiently take account of broader consumer benefits such as decarbonisation, alongside current statutory objectives.
- Removing barriers to connection for new demand (such as industrial decarbonisation and public EV chargers) – barriers to connection of new customer load can arise from inconsistent distribution business policies, processes and capacity, and constraints imposed by regulation.

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82 See a map of Lines companies in New Zealand here: https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-map. The total number of networks is often stated as 27, as one network (PowerNet) operates another two.

83 Boston Consulting Group. (2022, October). *The Future is Electric - A Decarbonisation Roadmap for New Zealand's Electricity Sector*.

84 Decarbonisation projects occur on a much shorter timeline than distribution businesses are used to, or the regulatory system can easily allow for.

- Cost allocation to support network investment ahead of immediate need – the cost of anticipatory capacity or network upgrades that provide for future growth can be allocated to the initial connecting customer.[85] This can add a barrier to connection of both distributed generation and new demand, or result in inefficient investment.
- Pricing signals to provide efficient use of networks – current distribution pricing may not adequately incentivise changes to retail pricing, or the provision of distributed flexibility, needed to support more efficient use of networks.[86]

219. To the extent that there are problems in these areas, it may be that current regulatory processes will adequately address them, or that broader changes are necessary at the system level (including regulatory change or government funding).

*Questions*

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|---|---|
| 29. | Do you agree we have identified the biggest issues with existing regulation of electricity distribution networks? |
| 30. | Are there pressing issues related to the electricity distribution system where you think new measures should be looked at, aside from those highlighted in this document? How would you prioritise resolving these issues to best enable the energy transition? |

## NETWORK INVESTMENT MODEL TO SUPPORT THE ENERGY TRANSITION

220. Like Transpower, distribution businesses are monopoly providers regulated by the Commerce Commission (Commission) under Part 4 of the *Commerce Act 1986* to ensure they provide services efficiently. All distribution businesses are subject to information disclosure requirements. Distribution businesses which are not community owned are also subject to price-quality regulation. Price-quality regulation involves:

- setting revenue caps to ensure distributors are limited in their ability to make excessive profits
- setting efficiency incentives that encourage distributors to out-perform regulatory allowances
- regulation of network quality standards that aim to ensure efficiency gains are not at the expense of reliability.

221. Distribution businesses have raised the following as regulatory barriers in relation to efficient network investment that enables decarbonisation and lowers whole of system costs:

85 This issue is often referred to as first mover disadvantage.

86 The Climate Change Commission has noted a similar set of issues in its draft advice on the second ERP. See Climate Change Commission. (2023, April). *2023 Draft advice to inform the strategic direction of the Government's second emissions reduction plan*. Available at: https://www.climatecommission.govt.nz/our-work/advice-to-government-topic/advice-for-preparation-of-emissions-reduction-plans/2023-draft-advice-to-inform-the-strategic-direction-of-the-governments-second-emissions-reduction-plan-april-2023/

- Current regulatory objectives focus regulatory attention on efficient service provision and do not sufficiently take account of considerations in section 5ZN of the *Climate Change Response Act 2002* (CCRA).[87] This may discourage some investments that would deliver sustainability benefits for consumers. This issue is discussed in detail in Chapter 9.
- Regulated expenditure is set for a five-year period. Many stakeholders consider that there isn't enough flexibility to vary regulated expenditure during that time, in the face of increasing uncertainty and the potential for changed circumstances as part of the energy transition. 'Reopeners' (formal requests to the Commission to reconsider regulatory settings during a regulatory period) are available under existing regulation and give scope to increase expenditure during the regulated period. However, stakeholders consider these are difficult to initiate and expensive to complete.
- Regulatory incentives may be skewed to encourage investments in capex rather than opex, even when opex investments (which include non-network solutions for flexibility) may be more cost effective.
- Regulatory settings are driven by historic trends, and are no longer appropriate given the step change in investment required to support the energy transition.

222. The first issue above (consideration of section 5ZN of the CCRA) is discussed further in Chapter 9. The remaining issues are currently being considered through existing regulatory processes being run by the Commission.

## WHAT IS ALREADY UNDERWAY?

223. As noted in Chapter 7 above, on 14 June 2023, the Commission published draft decisions on the 2023 Input Methodologies Review (IM Review) which will apply to distribution businesses. Consultation on the IM Review closes in early August 2023, with final decisions due in December 2023. The Commission will also undertake a reset of distribution business default price-quality paths and is undertaking a targeted review of information disclosure requirements for distribution businesses.

224. The Commission has indicated how it has considered issues raised by stakeholders in its draft decisions on the IM Review (including some of the issues outlined above), provided a view on whether issues raised are genuine barriers or not, and proposed solutions. Some of the proposed solutions will involve changes to the IMs and others will fall under the default price quality path reset or information disclosure requirements.

225. The Electricity Authority (Authority) also regulates some aspects of distribution businesses. It is considering updating regulatory settings for distribution networks, and it reviews distribution pricing practices regularly.

87 Section 5ZN of the *Climate Change Response Act 2002* (2050 target and emissions budget are permissive considerations) sets out the following matters for consideration by decision-makers: If they think fit, a person or body may, in exercising or performing a public function, power, or duty conferred on that person or body by or under law, take into account — (a) the 2050 target; or (b) an emissions budget; or (c) an emissions reduction plan.

### *Questions*

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|---|---|
| 31. | Are the issues raised by electricity distributors in terms of how they are regulated real barriers to efficient network investment?<br><br>Please give reasons for your answer. Is there enough scope to address these issues with the current ways distributors are regulated? If not, what steps would you suggest to address these issues? |
| 32. | Are there other regulatory or practical barriers to efficient network investment by electricity distributors that should be thought about for the future? |

## REMOVING BARRIERS TO NEW CONNECTIONS

226. Electrifying the vehicle fleet will be an important step towards a zero-carbon future. To meet emission reduction targets, the EV fleet will need to expand to 1.5 million EVs by 2035. Expanding charging capacity ahead of growth will be key to supporting transport electrification. The government recently consulted on a draft EV charging infrastructure strategy. The draft strategy highlights the goal to maximise the opportunity for a market-led rollout of public EV chargers to support our vision for a national charging network and sets out an action to:[88]

> Ensure the network connection process and pricing for firms wishing to connect public EV chargers to distribution networks is efficient and enabling. And to investigate changes to the current system that could reduce 'first mover disadvantage'.

227. A range of challenges to connecting public EV chargers to distribution networks have been identified by stakeholders, including public EV charger investors. To achieve the necessary investment in public EV charging infrastructure ahead of demand, genuine barriers to commercial investment must be addressed.

228. Similar connection challenges have also been raised in the context of electrifying process heat, by Government Investment in Decarbonising Industry (GIDI) Fund applicants. DETA notes in its report for the Climate Change Commission on *Non-cost barriers to Decarbonisation of Process Heat*,[89] that the fundamental set up of distribution businesses clashes with the push to decarbonise process heat. For example, timelines for GIDI Fund applications incentivise a less than 6-month plan and design process, with implementation typically within 12 months. These are shorter timelines than distribution businesses are used to and can result in lack of capacity and processes to facilitate timely connection of large decarbonisation projects.[90]

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88 Ministry of Transport. (2023, March). *Charging Our Future: a draft long-term electricity vehicle charging strategy for Aotearoa New Zealand*. Available at: https://consult.transport.govt.nz/policy/charging-our-future/

89 Climate Change Commission. (2023, April). *Non-cost Decarbonisation Barriers for Process Heat*. Available at: https://www.climatecommission.govt.nz/public/Advice-to-govt-docs/ERP2/draft-erp2/DETA-Non-cost-decarbonisation-barriers-for-process-heat.pdf

90 The report also notes that distribution businesses cannot invest proactively in the network to support connection of large-scale electrification projects, without the ability to recover those costs fairly due to the default price paths allowed by the Commerce Commission. This issue is discussed earlier in this chapter.

### *Connection costs*

229. Stakeholders indicate that connection costs[91] can be a barrier to investment, as they are a significant portion of the capital cost of projects including public EV chargers, hydrogen production and process heat electrification projects.

230. In the majority of cases distribution businesses have few regulatory incentives to put downward pressure on costs passed through to the customer as upfront connection charges. The connecting customer has limited ability to shop around for a lower cost solution,[92] increasing the risk that connection costs may be inefficiently high.

231. Stakeholders note connection costs often lack transparency. For example, temporary traffic management costs associated with providing new connections have been noted to be unexpectedly high and can make up a significant part of the connection cost.

### *Connection process and design*

232. Connection process for accessing distribution networks can take a long time (in some cases several months or more) because of:

- regional inconsistency due to the differing approaches of distribution businesses and local councils, including lack of a standardised process for load connections
- delays in responding to connection requests
- delays in importing transformers, where transformer upgrades are required to facilitate connection
- splitting of works contracted by different parties across different suppliers, with protracted timeframes between each step of the works being completed
- complexities due to size of the additional load and location of the new load, particularly if it is close to a grid exit point and engineering studies and/or significant infrastructure investments are needed.

233. In some process heat electrification projects and in hydrogen production, customers may be able to provide distributed flexibility from their own operations and be willing to accept lower reliability standards for their network connection. Bespoke solutions would be required for these connecting customers. However, not all distribution businesses offer such a service.

### *Visibility of current network capacity and congestion*

234. Connecting parties may not have of visibility of the amount of capacity on a distribution network before network upgrades are required to provide a new connection. Without this

[91] Connecting customers face connections costs associated with providing connection to the network, civil works cost (ie, trenching along busy roads to supply power from the network) and associated temporary traffic management costs. Connecting customers may also face capital contribution costs for network upgrades or reinforcements that are required to provide the connection.

[92] Connecting customers can undertake their own civil works, although there are several requirements on customers when doing so which could create barriers for smaller customers.

information connecting customers are unable to choose to connect in areas with existing capacity and lower connection costs. First mover disadvantage is also cited as an issue for larger capacity public EV chargers and other industrial connections, and is discussed in Chapter 10.

### WHAT IS ALREADY UNDERWAY?

235. Electricity Networks Aotearoa (ENA) has agreed to work together with industry consortium Drive Electric to work towards facilitating more efficient connection of public EV charging sites to electricity distribution networks.

236. The Commission is undertaking a review of information disclosure requirements. This will allow the Commission to monitor the performance of distribution businesses in providing new connections. It could also give connecting customers better information about network capacity and congestion. The review could require distribution businesses to provide more transparency over pricing and descriptions of the potential for large new connections.

237. In July 2023, the Authority released an issues paper on targeted distribution pricing reform which includes the variation in distribution connection approaches for load customers, including public EV chargers.[93]

238. Separately, the Authority aims to investigate whether there are other regulatory barriers to the roll-out and adoption of EV technology as part of its work on updating the regulatory settings for distribution networks. It will also seek feedback on a number of potential solutions, including methods to encourage change, or stronger options such as changes to the *Electricity Industry Participation Code 2010* (Code). If this consultation process identifies any issues which should be treated as priority, the Authority will seek to address these (potentially proposing amendments to the Code) before the end of this year.

239. Government co-funding already supports investment in decarbonisation of process heat through the GIDI Fund, and for public EV charging through the Low Emissions Transport Fund. A $120 million fund was announced in Budget 2023, that will provide co-funding to stimulate private sector investment in EV charging infrastructure across the country.

240. EECA is piloting improvements to its EV Fast Charging Hubs Strategy to help provide greater certainty to charging providers on costs, timings and better information on where further EV infrastructure would be best placed.

### FURTHER MEASURES TO CONSIDER?

241. Increasing contestability for the provision of connection assets could help address concern over inefficient costs. The Authority could explore the option of an access regime for load connections. This could consider distribution business requirements for who can do connection work (including design) and/or what equipment can be used. Options could also address hurdles to connecting customers undertaking their own civil works due to local Council requirements.

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[93] Electricity Authority (2023, July). *Targeted Reform of Distribution Pricing*. Available at: https://www.ea.govt.nz/documents/3367/Issues_Paper_-_Target_reform_of_Distribution_Pricing.pdf

242. Cost allocation through regulatory settings for connection assets can spread the costs in such a way as to lower the barriers for the connecting customer. While this could accelerate decarbonisation, it could lead to costs being borne by those who can least afford it.

### *Addressing Connection Process Barriers*

243. Part 6 of the Code sets out a framework to enable connection of distributed generation (DG). To help address some of the barriers outlined above, the Authority could explore whether a dedicated access regime similar to Part 6 of the Code could be applied to new electrified load connections.

244. Part 6 regulates DG connections by:

- requiring distributors to provide information to support connections, including required connection and operation standards, application forms, information about power export limits on the network, and approved inverter makes and models
- providing clarity on the process for obtaining approval and timeframes
- allowing connecting parties to use standard, regulated connection terms if they are unable or don't want to negotiate a connection contract with the distributor;
- providing a default process for disputes resolution
- setting out pricing principles that regulate distributors' ability to charge for connection costs (based on an 'incremental cost' model), except to the extent the parties' contract out of these under a connection contract.

245. A dedicated access regime similar to Part 6 of the Code could be created for, and applied to, existing and new electrifying load.

### *Questions*

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|---|---|
| 33. | What are your views on the connection costs electricity distributors charge for accessing their networks? Are connection costs unnecessarily high and not reflective of underlying costs, or not? If they are, why do you think this is occurring? |
| 34. | If you think there are issues with the cost of connecting to distribution networks, how can government deliver solutions to these issues? |
| 35. | Would applying the pricing principles in Part 6 of the Code to new load connections help with any connection challenges faced by public EV chargers and process heat customers? Are there other approaches that could be better? |
| 36. | Are there any challenges with connecting distributed generation (rather than load customers) to distribution networks? |

### *Cost allocation to support efficient network investment ahead of connections*

246. Where a customer wishes to connect (or expand an existing connection), distribution businesses can choose what portion of the total cost of that connection is allocated to the connecting customer upfront. In some cases, distribution businesses allocate a high proportion of the cost to the initial customer via an upfront payment. The remaining cost is pooled with the distribution business' other costs and recovered over time through distribution charges. Requiring the first mover to carry a high proportion of anticipatory

investment costs until subsequent customers connect may discourage the first mover from connecting or result in the first mover building a lower capacity investment. This could lead to delays in otherwise efficient investments for electrification or renewable generation. This issue is often referred to as 'first mover disadvantage'.

247. This section asks whether there is a case for departing from the current approach outlined above, to better support decarbonisation. It asks whether there is a way to preserve the efficiency benefits of building ahead of demand without initially allocating many or all of the costs of build to the first mover.

248. However, a change to the status quo could also create issues. For example:

- Local electricity consumers could be required to bear the cost of anticipatory capacity to support decarbonisation.[94] This might shift costs onto consumers who are already in energy hardship.
- Distribution businesses could take on the cost of anticipatory capacity until future customers connect, and then charge these customers a premium for the risk of carrying that capacity. However, distribution businesses consider that the pricing principles under Part 6 of the Code do not allow them to charge a premium to future DG connections.[95]

### *Cost allocation for connection of distributed generation*

249. Part 6 (Schedule 6.4) of the Code already places some limits on the cost distribution businesses can allocate to connecting customers. Part 6 sets out pricing principles for connection costs that can be charged to DG customers (such as new solar or wind farms). The pricing principles mean that distribution businesses can only allocate incremental costs to new DG connections, unless the connecting party agrees to a different pricing approach (under a negotiated connection contract). However, the pricing principles do not apply to load customers.

250. In September 2022 the Authority issued an open letter[96] that set the following expectations for connection asset cost allocation through distribution businesses' distribution pricing and capital allocation policies:

- in the first instance, the distributor should charge the first mover based primarily on the cost required to supply them
- distributors should rebate the first mover as subsequent movers connect, such that the first mover and subsequent movers end up paying a share based on their comparative needs.

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[94] This would involve spreading the cost of anticipatory capacity over the existing customer base. Under current regulatory settings, the extent of any cost recovery risk will be dependent on what level of connection capex and anticipatory capacity is already provided for under distributors' price-quality paths.

[95] The Electricity Authority released guidance for distributors in late 2022 on the interpretation of the incremental cost rule in Part 6 of the Code (see para 249 of this issues paper). However, this guidance is not an amendment to the Code to allow distribution businesses to allocate a risk premium to future customers.

[96] Electricity Authority (2022, September). *Open Letter to Distributors*. Available at: Letter_to_distributors_on_pricing_reform.pdf (ea.govt.nz)

251. However, this direction does not fully address the first mover disadvantage described above because distributors can still allocate anticipatory capacity costs to the first mover until second and subsequent customers connect.

## WHAT IS ALREADY UNDERWAY?

252. The Authority intends to review capital contribution practices and work is underway to address significant first mover disadvantage issues facing customers connecting to distribution networks. In July 2023, the Authority released an issues paper on targeted distribution pricing reform. Separately, the Authority will investigate whether there are other regulatory barriers to the roll-out and adoption of EV technology as part of its work on updating the regulatory settings for distribution networks.

253. Stakeholders argue that the Commission could reduce the recovery risk associated with forecasting uncertain connection and system growth demand – for example, through dialled-back efficiency incentives or reopener provisions. The Commission published draft decisions on their review of input methodologies for consultation, on 14 June 2023.

## FURTHER MEASURES TO CONSIDER?

### *Government underwrites and alternative cost recovery models*

254. To support connection of distributed renewable generation or electrification projects, the Government could support investment in anticipatory capacity by meeting costs until future customers connect.[97] This could be facilitated through the formation of a Renewable Energy Zone which includes distribution networks. This is discussed further in Chapter 11.

255. Delaying cost recovery is another way to allocate more of the cost of anticipatory investment to future customers who will use this capacity. The Commission could choose to weight recovery of asset costs towards the end of the asset life. If this delayed cost recovery was reflected in distribution pricing, it could make the upfront cost less significant for investors. However, such a delay in cashflows may have a negative impact on distribution businesses' ability to finance future investment, which may outweigh any advantages.

### *Different pricing models*

256. The Authority could choose to implement a more directive pricing regulatory model as is the case in other jurisdictions. For example, in the Netherlands connection costs are fixed for different scales of connection, prescriptive distribution pricing formulas are applied, and a standardised approach is used to determine ongoing distribution charges (see Box 7 below). However, a model of this kind which requires integrated regulation of revenue recovery, and network quality and distribution pricing would require a radically different approach to regulating distribution networks in New Zealand.

97 Government would also take on the risk of future customers not connecting.

| Box 7: A Dutch distribution pricing model |
| --- |
| In the Netherlands, distribution pricing tariffs are set for each distribution system operator (DSO) by following tariff codes, which explain how regulated revenues translate to the various tariffs.<br><br>Connection assets are included as part of the DSO's regulated asset base. Connecting customers can have capped upfront connection costs with any 'unders or overs' associated with these charges spread across other customers.<br><br>DSOs are regulated monopolies in the Netherlands and the intent of the regulation is similar to that in New Zealand. Regulation of revenues, service quality and prices for DSO are undertaken by the Netherlands Authority for Consumers and Markets. Regulatory goals in the Netherlands include:<br>• providing network operators with an incentive to operate in an efficient manner<br>• preventing network operators from charging tariffs above the (efficient) cost level<br>• allowing network operators an appropriate return on investments<br>• encouraging optimal quality of transport for electricity DSOs.<br><br>Regulated tariffs codes determine how costs are distributed between all system users, and allocate cost on a capacity basis. Customers have a fixed transport right in kilowatts (or based on connection capacity size).[98]<br><br>Regulators use 'benchmark regulation' to discourage too much investment, so that investments should lead to output. |

### *Questions*

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| 37. | Are there different cost allocation models addressing first mover disadvantage (when connecting to distribution networks) which the Electricity Authority should explore, potentially in conjunction with the Commerce Commission? |
| 38. | Should the Electricity Authority look at more prescriptive regulation of electricity distributors' pricing? What key things would need to be looked at and included in more prescriptive pricing regulation? |

## PRICING SIGNALS TO PROVIDE EFFICIENT USE OF NETWORKS

257. Efficient distribution pricing signals can help to incentivise efficient uses of distribution networks, including to load shift demand to support efficiency. This can lower overall costs for the provision of networks, providing for greater equity and affordability for distribution consumers.

258. Distribution pricing is regulated by the Authority. Currently the approach is light touch, involving voluntary guidance provided through pricing principles set out by the Authority. Distributors publish their pricing structures annually and these are reviewed by the Authority

98 Information on tariff codes set out here is based on a presentation provided by Enexis Group, one of the DSOs in the Netherlands.

using scorecards, with feedback provided to distributors. Internationally more directive regulation of distribution pricing is often used.

259. The Market Development Advisory Group (MDAG) has stressed the importance of using distribution tariffs to signal congestion. A high proportion of distribution networks (21 out of 29) now offer time-of-use distribution charges, to incentivise customers or their agents to shift load to less congested times, when distribution tariffs are lower.

260. Distribution price signals may not be significant enough to incentivise changes to retail pricing or alternative action to procure flexibility.[99] For retail customers to see distribution price signals that can incentivise efficient use of distribution networks, retailers must pass through these prices to consumers or find alternative ways to incentivise this behaviour. Retailers often smooth these pricing signals to make them more attractive for their retail customers.

261. We discuss the importance of retail pricing to incentivise investment in DER and provision of distributed flexibility in the Chapter 10.

262. Currently retailers need to navigate different distribution pricing structures from all 29 electricity distributors. More standardisation of distribution pricing could reduce the complexity for retailers associated with navigating different pricing structures. It could also support customers who are applying for direct connections across the country in different distribution networks by reducing the number of different pricing structures they must navigate.

### WHAT IS ALREADY UNDERWAY?

263. The Authority has also recently issued guidance to distributors on how to appropriately pass-through transmission charges imposed by Transpower under its new transmission pricing methodology. In July 2023, the Authority released an issues paper on targeted distribution pricing reform, which explores high-priority issues, including the use of distribution tariffs to signal the cost of capacity expansion required to address network congestion, reduction of off-peak charges, connection cost issues and retailer responses to distribution pricing.

### FURTHER MEASURES TO CONSIDER?

264. The Authority will use the results from its 2023 scorecards on distribution businesses pricing to inform further considerations related to distribution pricing. In the past the Authority has expressed some frustration with the responsiveness of distribution businesses to feedback about their pricing practices.

### *Structures for regulatory development*

265. As noted above, an integrated approach is a feature of Dutch distribution regulation, and is undertaken by a single regulatory body in many countries. Some stakeholders have said that

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[99] Network congestion occurs infrequently and could be signalled most effectively if distributor price signals better reflect congestion on networks - for example, by providing higher prices to reflect congestion during the most constrained trading periods over the year. This could help incentivise retailers and large industrial customers who pay these network 'use of system’ charges directly to distributors, to respond to these price signals.

New Zealand has an overly complex division of responsibilities between the Authority and the Commission, such that conflicting regulatory signals are given, which prevent an integrated approach like the Dutch model.

### *Questions*

| | |
|---|---|
| 39. | Do current arrangements support enough co-ordination between the Electricity Authority and the Commerce Commission when regulating electricity distributors? If not, what actions do you think should be taken to provide appropriate co-ordination? |

# 9 Is the government’s sustainability objective adequately reflected for market regulators?

266. The government’s objectives described in the introduction to this issues paper include security and reliability, resilience, and equity and affordability, all alongside the sustainability objective: that our energy system transitions at the pace and scale required to support net zero by 2050.

267. This chapter considers whether the statutory objectives for the Electricity Authority (Authority) and the Commerce Commission (Commission) are closely enough aligned with the government’s sustainability objective for the energy system. Chapter 11 considers, separately, the challenge of balancing the government’s policy objectives across sustainability, reliability and affordability.

### *Statutory objectives for the Electricity Authority and the Commerce Commission*

268. The electricity industry is subject to specific regulation under the *Electricity Act 1992*, *Electricity Industry Act 2010*, *Commerce Act 1986*, and the *Energy Efficiency and Conservation Act 2000*. Regulators include the Authority, the Commission, and the Energy Efficiency and Conservation Authority (EECA).

269. Each regulator has its own specific statutory objectives and purposes, and is accountable for its performance against those objectives. The objectives that the Authority and the Commission must pursue are specified in their legislation.

Section 15 of the *Electricity Industry Act 2010* states the Authority’s objectives:

> The main objective of the Authority is to promote competition in, reliable supply by, and efficient operation of the electricity industry for the long-term benefit of consumers.
>
> The additional objective of the Authority is to protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers.
>
> The additional objective applies only to the Authority’s activities in relation to the dealings of industry participants with domestic consumers and small business consumers.

Section 52A of the *Commerce Act 1986* sets out the purpose of Part 4, according to which the Commission regulates natural monopoly assets:

> The purpose of this Part is to promote the long-term benefit of consumers in [markets where there is little or no competition and little or no likelihood of a substantial increase in competition] by promoting outcomes consistent with those produced in competitive markets, such that suppliers of regulated goods or services —
>
>> have incentives to innovate and to invest, including in replacement, upgraded, and new assets; and

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

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

are limited in their ability to extract excessive profits.

270. For example, when considering whether to approve major capital expenditure on a new transmission line, the Commission must consider the benefits to consumers of reliable power supply and the cost to consumers of the investment needed to achieve that reliability. The Commission *must* make decisions per its statutory objectives. It *may* consider wider matters that can affect electricity markets, such as the environmental and health impacts of a transmission line, or the greenhouse gas emissions of power stations and factories that may connect to the power line, or emissions costs arising under the Emissions Trading Scheme (ETS). While the Commission can consider such costs and benefits that are internalised within the electricity system, it can be challenging to give weight to social externalities such as the social cost of emissions over and above the ETS price.

271. The Commission (along with other government bodies) may, as outlined in section 5ZN of the *Climate Change Response Act 2002* (CCRA), consider the Government's emission reduction targets and plans, but in general they cannot give them greater weight if they are inconsistent with their statutory objectives.[100]

### *Do regulators place too little weight on decarbonisation objectives?*

272. Some stakeholders take the view that due to the statutory purpose in Part 4, the Commission cannot give appropriate weight to climate change and decarbonisation objectives, for example that it:

- cannot or will not adequately account for emissions reduction in the demand and generation forecasts that underpin all transmission and distribution investment planning
- must focus narrowly on electricity market costs and benefits, which means it cannot take into account trade-offs between, for example, higher electricity costs and lower petrol and diesel costs.

273. Even when stakeholders acknowledge that the Commission has the discretion to consider climate change, some have questioned whether that is enough. For example, Electricity Networks Aotearoa (ENA) noted:[101]

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[100] The *Climate Change Response Act 2002*, section 5ZN (2050 target and emissions budget are permissive considerations) sets out the following requirements: If they think fit, a person or body may, in exercising or performing a public function, power, or duty conferred on that person or body by or under law, take into account — (a) the 2050 target; or (b) an emissions budget; or (c) an emissions reduction plan. https://www.legislation.govt.nz/act/public/2002/0040/latest/LMS282052.html

[101] Electricity Networks Association. (2022, 11 July). *Part 4 Input Methodologies Review: Submission to the Commerce Commission*. Available at: https://comcom.govt.nz/__data/assets/pdf_file/0042/287997/Electricity-Networks-Association-Submission-on-IM-Review-Process-and-Issues-paper-and-draft-Framework-paper-11-July-2022.pdf

> ENA is firmly of the view that in interpreting the 52A objective to promote the long-term benefit of consumers, the Commission should explicitly recognise that addressing climate change is in the long-term interest of consumers.
>
> …addressing climate change is not optional and is fundamentally in the long-term benefit of consumers. Therefore, it is inconsistent that the framework only includes optional consideration of 5ZN of the CCRA. The ENA recommends the IM framework require consideration be given to 5ZN instead of the current discretionary approach.

274. More broadly, it is sometimes argued that distribution networks, and Transpower, focus on commercial motivations, and they require proactive regulatory incentives to steer them towards socially desirable investment to enable electrification and decarbonisation, and to promote resilience.

275. The Climate Change Commission in their recent draft advice to the Government on the second emissions reduction plan noted that the existing regulated investment framework for transmission and distribution infrastructure needs to be future proofed by looking to meet outcomes related to emissions reduction, system security and reliability, and affordability.

276. The 2018-2019 Electricity Price Review reviewed whether the statutory objectives of the Authority and Commission should be amended to include environmental and fairness goals. The review concluded that adding to their existing objectives could pull the regulators in too many directions, require difficult trade-offs between competing objectives and blur their accountability. The review did however identify a regulatory gap in the protection of households and small business consumers, and the *Electricity Industry Act 2010* was subsequently amended to give the Authority an additional consumer protection objective, which came into force on 31 December 2022.

### *Does Part 4 of the Commerce Act sufficiently account for climate change objectives?*

277. The Commission has released its position on how Part 4 relates to section 5ZN of the CCRA, taking into account the purpose of Part 4 of the *Commerce Act 1986* and relevant Court rulings.[102] The Commission considers that:[103]

> it may take into account the s5ZN considerations where they are not inconsistent with the 52A purpose, even if taking into account those considerations would not itself promote the 52A purpose

and has also stated that:

> we consider that, in practice, there will be real scope to take account of the permissive considerations under section 5ZN while promoting the section 52A purpose of Part 4.

278. Without specific examples, it is difficult to assess how the Commission's approach to section 5ZN will align with the purpose of Part 4. Given the pace of change required in terms of electrification and the government's climate change objectives, there is a question of

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102 *Unison Networks Ltd v Commerce Commission* [2007] NZSC 74, [2008] 1 NZLR 42.

103 Commerce Commission. (2022, 21 December). *Note of clarification – our Part 4 Input Methodologies Review 2023: Framework Paper*. Available at: https://comcom.govt.nz/__data/assets/pdf_file/0022/302593/IM-Review-Decision-Making-Framework-Clarification-note-s-5ZN-of-the-CCRA-21-December-2022.pdf

whether further clarification is required or whether an alternative approach is more appropriate.

## WHAT IS ALREADY UNDERWAY?

279. As noted above, in June 2023 the Commission published draft decisions on the IM Review which apply to distribution businesses and Transpower. In addition to the IM Review proposing changes which promote the purpose of Part 4 more effectively, the Commission has also recognised climate change considerations under section 5ZN of the CCRA.

## FURTHER MEASURES TO CONSIDER: MORE CENTRAL GOVERNMENT DIRECTION FOR REGULATORS

280. In this section we ask if there is need for specific mechanisms to be used to provide more central government direction to ensure transmission and distribution network regulatory settings support climate change objectives.

281. In particular, we consider whether there would be merit in progressing the same update in objectives for the market regulators as is underway in Australia, as described in Box 8, or issuing a Government Policy Statement (GPS).

**Box 8: An explicit new emissions reduction objective is being considered in Australia**

The Australian National Energy Objectives (NEO) are contained in the *National Electricity Law*, the *National Energy Retail Law* and the *National Gas Law* - the laws that govern the national electricity, gas and related retail markets in Australia. The Australian NEO, as stated in the *National Electricity Law*, is currently:

> to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:
> - price, quality, safety and reliability and security of supply of electricity
> - the reliability, safety and security of the national electricity system.

In August 2022, Australian Energy Ministers agreed to fast track the introduction of a specific emissions reduction objective into the NEO, as a first action under the National Energy Transformation Partnership. Then in December 2022, the Australian Department of Climate Change, Energy, the Environment and Water launched a consultation on proposed legislative changes to incorporate an emissions reduction objective into the national energy objectives, and a draft bill containing the new revised national energy objectives.

The aim is to integrate emissions reduction and energy policy in Australia’s national energy laws and provide greater clarity to Australia’s three energy market bodies – the Australian Energy Market Commission (AEMC), the Australian Energy Market Operator (AEMO) and the Australian Energy Regulator (AER) – to consider emissions reduction in how they undertake their respective powers and functions. These market bodies perform similar functions to New Zealand’s Electricity Authority and Commerce Commission. The new emissions reduction objective is also intended to send clear signals to wider industry, market participants, investors and the public, of the governments’ commitment to achieve a decarbonised, modern and reliable grid.

Consistent with the current approach to applying the objectives, the emissions reduction component will be one of a number of components or ‘outcomes’ (alongside price, quality, safety, reliability and security of supply) that decision makers under the national energy laws will be obliged to consider and have discretion to balance in making their decisions. In this way, the emissions reduction objective is not intended to sit above, or be prioritised over, the existing components within the objectives, but rather will be considered and balanced alongside the other existing components, in a way that maximises the overall objectives, in the long-term interests of consumer.

282. The current Australian objective framework is similar to that which current applies for our New Zealand regulators. The rationale for the Australian reforms under consideration could also apply in the New Zealand context.

283. Measures which could be further developed in New Zealand include:

- Amendments to the statutory objectives that apply to both the Authority and the Commission, similar to the Australian approach.
- A GPS, that the Minister of Commerce and Consumer Affairs could issue under section 26 of the *Commerce Act 1986*, and that the Minister of Energy and Resources could issue under the *Electricity Industry Act 2010*. A GPS could communicate the government's expectations that climate change objectives should be considered when regulators set market rules and consider investment proposals for Transpower and distribution networks. For the distribution sector, a Government Policy Statement could also communicate the expected benefits to consumers, across the whole of the energy system, that are associated with distribution network investment, and how these could be considered.
- In the *Commerce Act 1986* context, a GPS could be issued urgently ahead of the Commission's 2024 individual price-quality path reset for Transpower and default price-quality path for regulated distribution networks. However, a GPS may not change the status quo given the Commission has stated that it considers in practice there will be real scope to take account of the permissive considerations under section 5ZN of CCRA, while promoting the section 52A purpose of Part 4.

284. A GPS could be issued first, then be followed by a review of the regulators' objectives, if necessary.

### *Questions*

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|---|---|
| 40. | Will the existing statutory objectives of the Electricity Authority and Commerce Commission adequately support key objectives for the energy transition? |
| 41. | Should the Electricity Authority and/or the Commerce Commission have explicit objectives relating to emissions reduction targets and plans set out in law? If so,<br>• should those objectives be required to have equal weight to their existing objectives set in law?<br>• Why and how might those objectives affect the regulators' activities? |
| 42. | Should the Electricity Authority and/or the Commerce Commission have other new objectives set out in law and, if so, which and why? |

| | |
|---|---|
| 43. | Is there a case for central government to direct the Commerce Commission, when dealing with Electricity Distributors and Transpower, to take account of climate change objectives by amending the *Commerce Act 1986* and/or through a Government Policy Statement (GPS)? |
| 44. | If you answered yes to question 43, please explain why and indicate:<br>• What measures should be used to provide direction to the Commerce Commission and what specific issues should be addressed?<br>• How would investment in electricity networks be impacted by a direction requiring more explicit consideration of climate change objectives? Please provide evidence. |

# PART 4: RESPONSIVE DEMAND AND SMARTER SYSTEMS

Part 4, **Responsive Demand and Smarter Systems**, considers issues relating to increasing distributed flexibility.

Part 4 comprises Chapter 10 **Increasing distributed flexibility**, which looks at how the increasing uptake of distributed energy resources near homes and businesses is changing our electricity system. New technologies, including smart devices, are more readily available and the costs of storage are falling. This provides opportunities to use the benefits from distributed flexibility to improve electricity system reliability, resilience, security of supply and affordability.

This chapter seeks feedback on whether there are areas where government action could further support development of markets for flexibility, address barriers to uptake and risks, and enable consumers to make choices about investing in these technologies.

### *Focus for Part 4 – Responsive demand and smarter systems*

| | |
|---|---|
| **CHALLENGES** | • Uptake of distributed flexibility in Aotearoa is currently low compared to the opportunity<br>• The necessary capabilities, digital infrastructure and processes are not yet in place for distributed flexibility, and it is not clear whether these features will emerge organically |
| **WORK ALREADY UNDERWAY** | • Industry collaboration and investment in demonstration projects is underway<br>• $20 million of public innovation funding has been set aside for projects that utilise DER to reduce peak demand and increase network resilience<br>• The Market Development Advisory Group's (MDAG's) consultations, including on options to lift demand side participation in the electricity market<br>• The Electricity Authority (Authority) consultation on updating regulatory settings for distribution networks, including considerations related to access to smart meter data for distributors and flexibility traders<br>• The Commerce Commission's 2023 Input Methodologies Review, and targeted information disclosure review for electricity distribution businesses<br>• MBIE is developing changes to the *Energy Efficiency and Conservation Act 2000* to enable smart device standards to be set (eg smart EV charger standards) |
| **FURTHER POSSIBLE MEASURES TO CONSIDER** | • How best to support co-ordinated action to increase market access for distributed flexibility to efficiently provide flexibility services across the electricity system<br>• How to address barriers to investment in distributed flexibility and non-networks solutions to manage network congestion and offset network upgrades<br>• How to support uptake of consumer energy resources, including addressing issues relating to smart device standards and cybersecurity issues and smart metering<br>• How best to reduce barriers to, and accelerate uptake of, pricing that rewards flexibility |

# 10 Increasing distributed flexibility

285. Enabling distributed flexibility services will help to minimise the cost of New Zealand's transition to net zero by 2050.[104] Boston Consulting Group's (BCG's) *The Future is Electric* report suggests that a 'smart system' could save around $10 billion in costs on a net present value basis to 2050, and investment in smart technologies could unlock at least 2 GW of distributed flexibility by 2030, and 5.8 GW by 2050.[105] BCG's report noted that the pace of change required for a smart system is significant and will need to accelerate to address challenges as we transition toward a more highly renewable electricity system.

286. In this document, we use the term 'distributed flexibility' to describe all types of demand side flexibility, demand response and flexibility from distributed generation and batteries. Distributed flexibility can be provided by large scale distributed energy resources (DER)[106], or household-level consumer energy resources (CER).[107]

287. Distributed flexibility can offer increased electricity system reliability, resilience, security of supply and affordability. For example, smart control of EV charging could be used to shift demand from congested peak periods and to help balance intermittent renewable supply. This can offset the need for additional investment in distribution network capacity, as well as reducing the need for higher-cost dispatchable generation to meet peak demands.

288. Unlocking the value of distributed flexibility can increase choices for consumers over how they use energy and how much it costs, and support investments in local resilience. However, the uptake of distributed flexibility in Aotearoa is currently low compared to the opportunity.

289. This chapter is focused on issues relating to distributed flexibility. However, we note that energy efficiency could significantly reduce electricity system costs as we transition,[108] and there are a range of government initiatives underway to improve electricity efficiency

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[104] Sapere. (2020, July). *Distributed Energy Resources – Understanding the potential*. Available at: https://srgexpert.com/wp-content/uploads/2020/09/Distributed-Energy-Resources-Understanding-the-potential-main-report-final.pdf

[105] Boston Consulting Group. (2022, October). *The Future is Electric - A Decarbonisation Roadmap for New Zealand's Electricity Sector*. Page 11.

[106] DER are business-owned assets, and their primary purpose can be either to provide energy system services or to provide business services. They are generally larger in kW/kWh and can be connected at any voltage level on the distribution network. DER can be generation, storage and demand assets. Examples include medium-sized solar farms, wind farms, batteries, commercial EV fleet charging, and industrial and commercial demand-side response from equipment or buildings.

[107] CER are (residential) consumer-owned assets, and their primary purpose is to provide a non-energy system service such as heating a home or transportation. However, they can also control their operation to provide energy system services. CER are generally smaller in kW/kWh size and they are connected to the low-voltage distribution network at the consumer's premises. CER can include generation, storage, and demand assets, and common examples include EV charging (including vehicle to gird (V2G)), hot water, heat pumps, heating, ventilation and air conditioning (HVAC), home appliances, small-scale batteries and rooftop solar or small-scale wind.

[108] See EECA. (2019, July). *Energy Efficiency First*. Available at: https://www.eeca.govt.nz/insights/eeca-insights/energy-efficiency-first/?gclid=EAIaIQobChMI6c3aj6L9_gIVzRRyCh2HywfXEAAYASAAEgJhIPD_BwE

including the E3 programme,[109] Energy Transition Accelerator[110] and the Government Investment in Decarbonising Industry (GIDI) Fund.

## SUPPORTING CO-ORDINATED ACTION TO INCREASE MARKET ACCESS FOR DISTRIBUTED FLEXIBILITY

### *New Zealand's flexibility market is immature*

290. As recently noted by United Kingdom regulator Ofgem "high transaction costs, barriers to market entry, the limited value of individual services, limited access to information, and a lack of coordination persist" in flexibility markets.

291. The Electricity Authority's Market Development Advisory Group (MDAG) observed that: [111]

> A number of factors have slowed the widespread deployment of demand-side participation:
>
> Consumers' awareness and understanding of the possibilities for demand-side participation, and the various forms that could take.
>
> The incentives faced by consumers to manage their own consumption, particularly shifting consumption from one time period to another. With the prevalence of retail tariffs which are constant throughout the day, there is no financial incentive to shift consumption.
>
> The degree to which customers have to – and want to – actively manage demand side flexibility, including the trade-off between the service they require (e.g., heating, cooling and more recently state of charge of their electric vehicle) and how much flexibility is used to manage their own consumption costs.

292. New technology investment, for example, in sensors, automation, communication, algorithms and smart devices, can help automate distributed flexibility and can reduce the need for direct consumer engagement. This can unlock opportunities for a range of commercial arrangements and tariffs through which market participants can procure and reward distributed flexibility. To take advantage of new technology and enable distributed flexibility resources to fully realise their system value, we need to develop processes and capability to transact and co-ordinate flexibility, and to improve the cost reflectiveness of price signals and provide greater market access. This is especially true for CER, which are a key component of distributed flexibility.[112]

293. A key challenge inhibiting the uptake of distributed flexibility is the difficulty flexibility owners have in capturing the full range of revenue opportunities across different uses for

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109 EECA. (2023, June). *Equipment Energy Efficiency*. EECA website. Available at: https://www.eeca.govt.nz/regulations/equipment-energy-efficiency/

110 EECA. (2023, June). *Energy transition accelerator*. EECA website. Available at: https://www.eeca.govt.nz/co-funding/energy-transition-accelerator/

111 Market Development Advisory Group. (2022, November). *Enhancing wholesale market demand-side flexibility: Framework for Option Development*. Available at: https://www.ea.govt.nz/documents/1255/DSF-framework-paper-FINAL-1.pdf

112 New Zealand has established markets including the spot energy market (with real-time pricing), ancillary services and reserves market where flexibility from DER and CER can potentially be utilised. However, processes to transact flexibility, particularly from the owners of CER are still being developed.

such flexibility (such as ancillary services, spot energy services or network services). This kind of 'value-stacking' can help develop a viable business model for investment.

### *Barriers to collaboration and trials*

294. A coordinated and collaborative learning-by-doing process could facilitate development of the market for distributed flexibility and support uptake in Aotearoa, through:

- enabling development of common processes for transacting distributed flexibility
- improving data access and monitoring
- developing mechanisms to 'value stack' distributed flexibility services to different parts of the electricity system and ultimately enabling consumer choice
- developing processes to ensure use of flexibility in one part of the electricity system (for example, in response to spot prices) does not destabilise other parts of the supply chain (for example, network stability).

295. When benefits are shared with consumers and sector participants across the value chain, individual firms may not have incentives to meet the full cost of pilots and trials. Regulated stakeholders have indicated that, to date, innovation funding available through the regulatory system has been insufficient. There may also be lack of buy-in from some sector participants to new ways of doing things.

296. It is not yet clear whether demonstration projects face real constraints from regulation. For example, Ara Ake and Kāinga Ora have jointly developed a 'multiple trading relationships' (MTR) trial in Lower Hutt and Porirua that aims to reduce energy hardship for social housing tenants (Kāinga Ora customers). The trial involves a complex mesh of relationships between customers, retailers, and other market participants. In addition to a retailer selling electricity to a customer, the trial would allow another electricity retailer (contracted to Kāinga Ora) to manage solar electricity generated at the Kāinga Ora property. Such arrangements are prohibited under the *Electricity Industry Participation Code 2010* (Code), except where an exemption is granted.

297. Ara Ake and Kāinga Ora requested regulatory exemptions from the Electricity Authority (Authority), under the Code, to move ahead with the trial. The Authority granted an exemption in late June.[113]

## WHAT IS ALREADY UNDERWAY?

### *Industry driven development and implementation*

298. The Flex Forum is a diverse cross-industry group established in February 2022 to identify and progress the practical, scalable, and least-regret actions needed to integrate DER into the electricity system and to transact flexibility to ensure we are working towards the best long-term outcomes for consumers. The Flex Forum will facilitate collaboration on demonstration

[113] For more information, see: https://www.ea.govt.nz/news/general-news/solar-energy-sharing-for-social-housing-trial/

projects and communicate shared learnings from these projects, and progress key practical steps identified in its Flexibility Plan.

299. Electricity Networks Aotearoa has developed a Network Transformation Roadmap. It is supporting collaborative action to deliver on this roadmap and help reach national climate goals through its Future Networks Forum.

300. Regional distribution business groups such as the South Island Distribution Group and Northern Energy Group are collaborating to help develop a market for flexibility. These can provide shared lessons on practical processes to connect, use and transact flexibility and to inform households, businesses, and aggregators about opportunities to participate in these markets.

301. The Electricity Engineers' Association (EEA) is leading FlexTalk in partnership with industry and EECA. FlexTalk is an industry initiative to evaluate the processes that need to be in place to apply the OpenADR 2.0 (2.0a and or 2.0b) communication protocol to achieve active managed charging of EVs, enabling flexibility services to be utilised in the New Zealand electricity sector.[114]

### *Provision of contestable innovation funding for 'learning-by-doing' trials*

302. In Budget 2023 the government announced $50 million for distributed renewable energy projects. Over the next four years $20 million ($5 million per year) of this will be allocated to establish a new innovation fund to help manage our peak network demand and improve network resilience across the electricity sector. The fund will provide flexible support for innovative research and trials for both community and industrial scale distributed renewable energy with demand response capability. Learnings from these projects will help develop and increase capability, expertise and increase market access to distributed flexibility.

### *Other initiatives underway*

303. Ara Ake supports a range of businesses including start-ups to large organisations, to facilitate and support demonstration projects of new and emerging energy technologies across Aotearoa New Zealand. In 2022 Ara Ake also ran an 'Innovation Challenge' for the purpose of funding a pilot to provide optimised visibility, management and forecasting of peak demand and network constraints for a distribution business.

304. The Authority is generally considering how to make best use of its new exemption powers.[115] The Authority is also considering how else it can best support the development of distributed flexibility uptake in New Zealand. The Authority is considering what kind of data metering equipment providers provide to distributors and flexibility traders. The Authority's Future Security and Resilience (FSR) programme is focused on how to ensure that New Zealand's electricity system remains stable, secure, and resilient with increasing intermittent supply for

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[114] Electricity Engineers' Association. (2023, June). *Demand Flexibility Common Communications Protocols Project (FlexTalk)*. Electricity Engineers' Association website. Available at: https://www.eea.co.nz/Site/asset-management/adr-project/about-adr-project

[115] Changes under the recent *Electricity Industry Amendment Act 2022* changed the criteria under which the Electricity Authority could grant regulatory exemptions.

renewable generation and increasing distributed energy resources. This work involves collaboration between Transpower (in its role as System Operator) and the Authority.

305. MDAG has recently released an options paper to consult on the steps needed to prepare for a renewables-based electricity system. MDAG identified lifting demand side participation in the electricity market as one of five key priorities and noted that demand side flexibility (including demand response and load shifting) will play a much more significant role in higher price periods and should be able to compete efficiently with supply-side resources in delivering reliability.

## FURTHER MEASURES TO CONSIDER?

### *Providing direction for the sector*

306. Government leadership may be required to accelerate the development of the necessary capabilities, digital infrastructure and processes to support distributed flexibility. There is already a range of processes underway to improve co-ordination, and this section asks whether there are any additional actions that could be taken.

307. Providing more direction on government priorities for flexibility markets could support collaboration to reach a common future state. It can also increase certainty for the sector to make the necessary investments to enable digitalisation and greater use of distributed flexibility. It could also co-ordinate alignment of regulation to ensure the sector has the appropriate incentives and regulation in place to support this activity.

308. In the UK, the UK energy regulator (Ofgem) and government agency (BEIS) have taken a proactive role in the development of flexibility markets and provided strong direction and industry co-ordination. Ofgem have developed a programme of work based on its Smart System and Flexibility Plan,[116] working with trade associations and representative groups of all interested parties in the energy sector.

309. Ofgem has recently identified the need to define what the future digital infrastructure to trade distributed flexibility will look like and is currently consulting on different options.

| **Box 9: The UK regulator Ofgem is currently consulting on a future vision for a flex-centric electricity system** |
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| The UK has made significant progress on utilising distributed flexibility. In the 2021/22 financial year, distributors procured 3.7 GW of flexibility resources, equivalent to 500 MW of distributed flexibility on a prorated basis in New Zealand.[117]<br><br>However, Ofgem in its recent call for inputs to a vision for a flex-centric electricity system, which facilitates distributed flexibility, notes that it is not clear that this type of electricity system will emerge organically. |

116 See UK Department for Business, Energy & Industrial Strategy and Ofgem. (2021, July). *Transitioning to a net zero energy system: The Smart System and Flexibility Plan 2021*. Available at: https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021

117 Boston Consulting Group. (2022, October). *The Future is Electric - A Decarbonisation Roadmap for New Zealand's Electricity Sector*.

To support greater co-ordination and market access for distributed flexibility, Ofgem is currently requesting input on a common vision for distributed flexibility for the industry to unite behind to reach a flex-centric future. Ofgem is seeking input on the structure of common digital energy infrastructure, which would be provided by a system-wide flexibility exchange (SFE).

A SFE platform could facilitate the interaction between flexibility service providers and market operators through data exchange. It could make flexibility more commercially viable through easier participation in multiple markets, revenue stacking whilst making it easier for small assets to participate directly.

310. In New Zealand, the Government could perform a similar role and work with industry to develop, for example, specific options for the structure of our future digital platforms for trading flexibility.

311. An integrated digital market platform can enable owners of distributed flexibility to gain value from the full range of service.[118] It could set a path for co-ordination within distribution businesses and between distribution and transmission systems in relation to load and CER and DER forecasts, CER and DER operating assumptions, and the need to ensure that CER and DER schedules and dispatch in the wholesale market is feasible (considering physical network limits).

### *Supporting progress through Government engagement in industry collaboration*

312. In New Zealand, industry groups and regulators already have significant work programmes (as outlined above). We seek your feedback on whether there is any further action that could build on this existing work to help co-ordination.

313. For example, this could include more formalised collaboration by government and regulators with existing industry groups, utilising what has worked well in the UK context,[119] to help guide and accelerate development of flexibility markets.

### *Regular review of standards*

314. Technological developments also add to the need for regulatory flexibility. Mandated technology requirements must be regularly updated to reference the latest safety or device standards.

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119 In the UK, the Open Networks group is a good example of this type of collaboration and has accelerated the pace of local flexibility market development. It brings together electricity grid operators and works with the UK Government (through the Department for Business, Energy and Industrial Strategy), the energy regulator Ofgem, academics, industry experts and trade associations. The Open Networks programme has a strong focus on distributed system operation (DSO) and flexibility markets and is currently focusing on increasing participation and volume in the local flexibility market in line with actions from BEIS' and Ofgem's *Smart Systems and Flexibility Plan* (2021).

*Questions*

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| 45. | Would government setting out the future structure of a common digital energy infrastructure (to allow trading of distributed flexibility) support co-ordinated action to increase use of distributed flexibility? |
| 46. | Should central government see how demonstrations and innovation to help inform how trade of flexibility evolves in the New Zealand context, before providing direction to support trade of distributed flexibility? If yes, how else could government support the sector to collaborate and invest in digitalisation now? |
| 47. | Aside from work already underway, are there other areas where government should support collaboration to help grow and develop flexibility markets and improve outcomes? If yes, what areas and actions are a priority? |

## ADDRESSING BARRIERS TO INVESTMENT IN DISTRIBUTED FLEXIBILITY/NON-NETWORK SOLUTIONS

### *Underutilisation of non-network solutions*

315. In some cases, electricity distributors can lower costs for provision of services to their customers through use of distributed flexibility, referred to as non-network solutions (NNS), as an alternative to traditional network upgrades (poles and wires). While there has been a notable increase in NNS project development in New Zealand,[120] challenges to electricity distributor investment persist. For example:

- Electricity distributors often see NNS as being unreliable and difficult to integrate with their networks,[121] and procurement costs may be high, with no guarantee a lower cost NNS alternative can be found.
- In New Zealand we have many small electricity distributors who may not have dedicated resource to support procurement for NNS.
- Lack of information for engineers working within electricity distributors on NNS opportunities or cultural inertia could also result in a preference for traditional solutions.
- Limited distributed flexibility service offerings currently in the market may be deterring distributor use. This is a circular issue as increased demand would help support growth in offerings. Electricity distributors may need more support, or

[120] Electricity distributor Aurora Energy has contracted with solarZero for flexibility services from home solar and batteries providing an alternative to network upgrades in upper Clutha. Powerco (another electricity distributor) and solarZero established a partnership for a community-led non-network solution, providing to 1 MW of distributed battery network support to the northern part of the Coromandel.

[121] Non-community owned electricity distributors face regulated price-quality standards and if NNS does not provide regulated quality standards, electricity distributors could face penalties under the *Commerce Act 1986*.

different regulatory incentives[122] to encourage the investment that can support widespread use of NNS.

## WHAT IS CURRENTLY UNDERWAY?

### *Commerce Commission regulatory processes*

316. As noted elsewhere in this issues paper, the Commerce Commission (Commission) is undertaking a review of its input methodologies (the IM Review) and published draft decisions on the review for consultation, on 14 June 2023. The IM Review is considering how existing regulation impacts incentives for investment in network innovation (which is typically operating expenditure) and how longer-term benefits (beyond the 5-year price period) can be captured.

317. The Commission is also undertaking a targeted review of how information disclosure could allow it and other stakeholders to monitor the performance of electricity distributors in providing new connections. The review could also require more information on network congestion to help flexibility service providers better understand opportunities for provision of flexibility services from DER/CER. Distribution business innovation will continue to be a focus for the Commission.

318. There will be scope under the Commission's default price-quality path reset to consider regulatory 'sandboxing' – formal exemptions from default regulation to allow experimentation – to enable innovative activity. For example, an electricity distributor could be exempted from meeting standard 'quality' requirements for network services for a limited period, while it is trialling NNS.

### *Electricity Authority*

319. In December 2022 the Authority released an issues paper inviting feedback on priorities for updating the regulatory settings for distribution networks.[123] This document outlines the Authority's thinking on matters relevant to the market for flexibility services including equal access to data and information, market settings for equal access, and distributed energy resource standards. Informed by the feedback on the issues paper, the Authority is aiming to confirm its work programme for approximately the next 12 -24 months around August 2023.

320. The Authority is also supporting distribution networks to speed up pricing reform. Distribution pricing is important as it affects the timing, level and location of investments in new technology, such as DER/CER like solar panels, electric vehicles and batteries. The

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[122] 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. Distributors are required under Part 4 of the *Commerce Act 1986* to consider whether NNS are a viable alternative to network solutions and present this in their AMP.

[123] Electricity Authority. (2022, December). *Issues paper: Updating the Regulatory Settings for Distribution Networks*. Available at: https://www.ea.govt.nz/projects/all/updating-regulatory-settings-for-distribution-networks/consultation/regulatory-settings-to-support-non-network-solutions-and-flexibility-services/

Authority provides regular guidance to distribution networks on what good distribution pricing looks like.

## FURTHER MEASURES TO CONSIDER

### *Addressing barriers to investment in NNS and digitalisation related to the Commerce Commission price-quality regulation*

321. The previous chapter discusses incentives for investing in operational expenditure to procure NNS and increasing flexibility for regulated expenditure in future regulated periods, from April 2025, to support investment that enables decarbonisation and wider system benefits.

### *Co-funding for procurement of non-network solutions*

322. Innovation funding noted previously could increase supply of NNS. Additional funding could be allocated to co-fund electricity distributors to undertake procurement helping to de-risk electricity distributor procurement processes for NNS. Procurement funding could support distribution businesses to procure expertise to identify opportunities and identify needs for investment not only in the solution itself but also enabling data and monitoring capability. Shared learnings from the procurement process development could help support all distributors to adopt standardised approaches to procuring flexibility.

323. The $20 million innovation funding noted earlier in this chapter could support innovative solutions to maximise network infrastructure, provide lower cost solutions to network upgrades through distributed flexibility and potentially increase local energy resilience.

### *Dynamic operating envelopes*

324. A 'dynamic operating envelope' provides upper and lower bounds on the import or export of power in a given time interval for either individual DER/CER assets or a connection point. Internationally, dynamic operating envelopes are being explored to support the integration of DER/CER without breaching the physical and operational limits of distribution networks and to maximise the use of existing network capacity. Putting in place such operating limits for distribution networks would provide a backstop to avoid network outages associated with changing network uses. It could provide confidence for distribution businesses to increase their use of distributed and consumer energy resources. Implementing dynamic operating envelopes could form a useful step in moving towards distributed system operation.

### *Questions*

| | |
|---|---|
| 48. | Could co-funding for procurement of non-network services help address barriers to uptake of non-network solutions (NNS) by electricity distributors? |
| 49. | Would measures to maximise existing distribution network use and provide system reliability (such as dynamic operating envelopes) help in New Zealand? If yes, what actions should be taken to support this? |

## SUPPORTING UPTAKE OF CONSUMER ENERGY RESOURCES

325. In this section we consider measures to enable uptake of CER that are additional to development of value streams and information provision through flexibility market development.

### *Smart devices*

326. Smart devices (such as smart EV chargers) can unlock distributed flexibility from households and businesses. With suitable communication capability, smart devices can allow (with consumer permission) market participants to control demand from these devices. The value of flexibility in the electricity market will increase as supply from intermittent renewables increases. Smart devices that allow external control in response to supply variation at any time of the day and night (not just in peak periods) will be increasingly important to keep costs down and provide reliability and reduce consumer costs. However, the market may not, by itself, deliver optimal outcomes that ensure:

- sufficient interoperability between devices (related to communication protocols), so that consumers have choice over how and to who consumers provide distributed flexibility to
- appropriate cyber security, to provide confidence and safety for customers providing distributed flexibility from smart devices in their home or businesses.
- adequate visibility of smart devices, so that sector participants are aware of the potential opportunities for distributed flexibility
- off-peak use of smart EV chargers, to address the chance of unintended increases in peak demand.

## WHAT IS ALREADY UNDERWAY

### *Updating regulatory settings for distribution networks*

327. The Authority has a work programme to update regulatory settings for distribution networks. The Authority's aim is to have the right regulatory settings in place to promote competition and access to the distribution network, to better support the transition to a low-emissions future at the pace required and unlock the potential of CER (such as private EV chargers in the home). The work program covers issues relevant to distributed flexibility, such as the need to improve access to smart meter data and to improve visibility of CER (such as private EV chargers), and low voltage network congestion visibility.

328. The Authority is also taking the steps already described in paragraph 320.

### *Regulatory Settings for EV chargers*

329. In 2022 EECA released a green paper[124] for public consultation that sought feedback on government intervention to increase the uptake and improve the performance of smart

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[124] EECA. (2022, August). *Improving the performance of electric vehicle chargers: a green paper seeking input on ways to improve the energy performance of electric vehicle chargers*. Available at: https://www.eeca.govt.nz/assets/EECA-Resources/Consultation-Papers/EV-charging-Green-Paper-8-August-2022.pdf

private EV chargers. Stakeholder feedback indicated there is a strong case for government intervention and regulation.

330. MBIE is developing changes to the *Energy Efficiency and Conservation Act 2000* to enable standards to be set requiring devices (such as EV home chargers) to have demand response capability. EECA is considering other interventions such as a potential 'white list' of smart chargers that meet its voluntary 'Publicly Available Specifications' (PAS) requirements, and a potential Smart Tick to promote them.

### *Updating electrical safety standards*

331. Connection and operation of electrical appliances and related equipment on low voltage networks is governed by electrical safety regulations made under the *Electricity Act 1992*. The regulations make extensive use of international standards, which are incorporated by reference into the regulations. MBIE is currently progressing an update to numerous standards incorporated into the regulations, including *AS/NZS 4777*, relating to the connection of inverter-based systems. This is particularly relevant to provide up to date standards for distributed solar PV.

332. The *Electricity (Safety) Regulations 2010* require a supply of electricity to installations to be within 6 per cent of a range from 200V and 250V AC. A review of the voltage range prescribed in the regulations is included in MBIE's future work programme. This consideration is relevant to solar PV investment as a slightly higher upper voltage range could reduce the need for solar PV curtailment.[125]

## FURTHER MEASURES TO CONSIDER?

### *Smart device standards and regulation*

333. Intervention may be required to ensure smart devices have the necessary capabilities to maximise benefits to consumers and the electricity system, and are underpinned by the principles of interoperability, data privacy, grid stability and cyber security.

334. EECA previously consulted on default off peak charging settings for EV chargers (with a consumer override provision). We have heard a lot of support for this option, which addresses the problem that not all consumers will be equally engaged and committed to reducing the impact of charging on networks. Default settings would require smart chargers to charge off peak unless the consumer chooses to override it. We consider that this should be a feature of smart charging regulation.

| **Box 10: UK regulation of load control and energy smart appliances and service providers** |
| --- |
| The UK's *Energy Security Bill* sets out measures to ensure smart devices are not hacked or used in a way to cause harm to the consumer or the grid. It provides the UK Government powers to place requirements on energy smart appliances (such as EV chargers and heat pumps) and on providers who control the smart services remotely. The Government will have powers to: |

[125] Voltage limits in Australia have been changed and now allow voltage to be 10 per cent above and 6 per cent below the 200-250V range.

- introduce regulations to set minimum technical requirements for cyber security, interoperability, data privacy and grid stability
- mandate devices to have smart functionality
- prohibit sales of non-smart devices in the UK
- make load control activities licensable, for example, to meet requirements for consumer protection and cyber security.

Regulations made under these enabling powers will ensure that devices are secure by design, and that businesses capable of controlling smart devices are meeting minimum standards of cyber security and data privacy. The UK Government already has powers to regulate EV chargers through the *Automated and Electric Vehicle Act 2018*. The Bill provides additional powers to regulate all smart devices in a consistent manner. The UK Government is consulting with the industry experts including the UK's National Cyber Security Centre to design further measures needed to improve cyber security. Through such interventions, the UK Government aims to build consumer trust and confidence and expand uptake of smart devices.

The UK's Publicly Available Specifications for Energy Smart Appliances (PAS 1878 and PAS 1879) specify minimum requirements to deliver domestic demand response, allowing for innovation to continue on top.

### *Cyber security regulation*

335. Specific measures related to cyber security associated with smart devices and third-party access will be considered in the context of wider work underway by Government[126] to enhance the resilience of New Zealand's critical infrastructure system to all hazards and threats, both natural (such as earthquakes and floods) and man-made (such as cyber security incidents and espionage). New Zealand could consider the UK's example with regards to cyber security by placing requirements on energy smart appliances and the organisations who control them (load controllers). See Box 10 above on the UK's *Energy Security Bill*.

### *Questions*

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|---|---|
| 50. | What do you think of the approaches to smart device standards and cyber security outlined in this document? Are there other issues or options that should be looked at? |

### *Automated device registration*

336. The UK Government has an Automated Asset Registration Programme which aims to support the development of an automated secure data exchange process for registering small-scale energy assets and collecting and accessing small-scale energy asset data.

[126] The Department of the Prime Minister and Cabinet (DPMC) recently released a discussion document on strengthening the resilience of critical infrastructure. See DPMC. (2023, June). *Strengthening the resilience of Aotearoa New Zealand's critical infrastructure system*: *Aotearoa New Zealand has a secure platform for a productive, sustainable and inclusive economy – Discussion Document.* Available at: https://consultation.dpmc.govt.nz/national-security-group/critical-infrastucture-phase-1-public-consultation/

### *Questions*

| 51. | Do you think government should provide innovation funding for automated device registration? If not, what would best ensure smart devices are made visible? |
|---|---|

### *Retail Pricing*

337. MDAG noted that many customers presently have tariffs with fixed prices, insulating them from wholesale prices, that provide no control over their discretionary consumption to their retailer (which faces wholesale price volatility on their behalf). MDAG considered that customers should be able to elect from a range of contractual relationships with their electricity service providers that reflect their appetite to directly engage in providing flexibility, to leave the use of their flexibility to someone else, or not to provide flexibility at all. MDAG identified a high prevalence of fixed-price variable volume retail electricity pricing as a barrier to incentivising customers to make efficient decisions on investment and provision of distributed flexibility.[127] The Innovation and Participation Advisory Group's 'Equal Access' advice recommended that the Authority reinforce the message that cost-reflective prices are an important step in the transformation to an efficient transactive network with widespread uptake and use of CER.[128]

## WHAT IS ALREADY UNDERWAY

338. MDAG set out the following options to address barriers to uptake of distributed flexibility in the wholesale electricity market associated with current high fixed price variable volume retail pricing, including:

- monitoring the provision and uptake of tariffs which reward demand side flexibility
- if monitoring reveals slow uptake because of limited availability of such tariffs, requiring retailers to offer tariffs which reward flexibility
- facilitating rapid adoption, by retailers, of the high frequency metering data that will underpin these tariffs - where smart meters are in place, retailers should use metered data for billing purposes by 2025.

339. The ability of electricity retailers to introduce innovative pricing structures has, to an extent, been constrained by the *Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004*. These regulations are currently being phased out over five years and will be fully removed from 2027. We expect that, as the constraints of the regulations lessen, more innovative tariffs will be developed, including at the retail level. Some retailers now offer tariffs designed for EV owners or offer time of use pricing.

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127 Market Development Advisory Group. (2022, November). *Enhancing wholesale market demand-side flexibility: Framework for Option Development*. Available at: https://www.ea.govt.nz/documents/1255/DSF-framework-paper-FINAL-1.pdf

128 See Innovation and Participation Advisory Group. (2019, April). *Advice on creating equal access to electricity networks*. Available at: https://www.ea.govt.nz/documents/525/IPAG_advice_on_creating_equal_access_to_electricity_networks.pdf

340. The Authority work to implement real-time pricing for the wholesale market, and the introduction of the dispatch notification product described earlier in Chapter 5, is also relevant here.

## WHAT ELSE MIGHT WE NEED TO CONSIDER?

341. We are interested in views on whether stronger regulatory requirements are needed to accelerate provision of pricing which rewards flexibility without stifling competition or encouraging behaviour which increases congestion on networks. Examples could include requirements on retailers to provide customers with the lowest cost retail price plan if they ask for it or a requirement for retailers to offer an annual health check where they inform customers whether they would be better off on a lower cost tariff.

342. The *Consumer Care Guidelines* already advise retailers to undertake annual tariff check-ups for those customers who are struggling to pay their bills – by providing customers with information about the lowest cost tariff for their electricity usage patterns on an annual basis. However, the *Consumer Care Guidelines* provide only guidance to retailers – they are not mandatory. If the Authority decides to make the *Consumer Care Guidelines* mandatory (as some stakeholders are suggesting it should), a requirement for a 'best tariff check' could be added as applicable for all customers. Alternatively, the government could require all retailers to provide a regular tariff check (the best of its own tariffs, if the household's circumstances don't change) for all customers.

### *Question*

| | |
|---|---|
| 52. | Are extra measures needed to grow use of retail tariffs that reward flexibility, so as to support investment in CER and improved consumer choice and affordability? |

## SUPPORTING THE UPTAKE OF BATTERIES (OR SOLAR PV COUPLED WITH BATTERIES)

343. Local battery storage (which is usually coupled with solar PV) could play a useful role enhancing system reliability – provided the battery and solar system can continue operating when the grid is down. A role for local batteries to enhance reliability could be especially relevant in more remote communities, where supply is less reliable than in urban centres or areas closer to generation. However, uptake in New Zealand is currently low relative to countries such as Australia.

344. solarZero's battery and solar PV systems, and its recent launch as a virtual power plant (VPP), is an example of localised storage offsetting local network investment, and thereby lowering costs to local consumers and increasing electricity system and local resilience. Investment by solarZero was partially funded through contractual arrangements to provide flexibility to the local distribution network. solarZero can also gain revenue streams through provision of distributed flexibility to other market participants or through provision of ancillary services.

345. This type of contractual revenue certainty is not available in all situations or to households investing in battery systems coupled with solar. Access to capital could also be a barrier for household investment in batteries alone or with solar.

## WHAT IS ALREADY UNDERWAY

346. In Australia, nearly a third of all households have solar energy systems.[129] Battery system uptake is also growing fast, with over 180,000 households reported to have a local storage system as at March 2023.[130]

347. Many Australian states have incentivised the uptake of solar PV via regulated feed-in tariffs (FITs), then minimum FITs. For example, the Victorian Essential Services Commission sets the minimum rates electricity retailers pay households for electricity exported to the grid.[131] There is now a general expectation by customers that their retailers offer a FIT. These measures are likely to have driven the uptake of both solar PV, and local batteries. Whilst such tariffs are on offer in New Zealand, these are unregulated.

## FURTHER MEASURES TO CONSIDER?

### *Feed-in-tariffs for distributed solar and batteries*

348. Australia and New Zealand have very different peak demand periods. In Australia, peak demand usually occurs during hot summer daytime hours – when the sun is shining. In contrast, New Zealand's peak demand hours usually arise in the winter either early morning or evening, when the sun is not shining (and wind has dropped). As such, solar PV on its own is unlikely to play the same useful role as it has in Australia.

349. The general view to date by government agencies has been that widespread financial support of roof-top PV has not been warranted, as grid scale renewables are typically lower cost than roof-top PV, and also lower cost than fossil fuelled generation. So, promoting rooftop PV would probably just displace commercial investment in grid-scale renewables.

350. However local battery storage in New Zealand (which is usually coupled with solar PV) that is interoperable could play a useful role in enhancing system reliability – provided the system can continue operating when the grid is down. Commentators in Australia have noted that it is both the level, and the certainty, of a FIT that provides investment certainty to households considering installing solar and batteries. Rooftop solar is still a sizeable investment for many households in a relatively new technology. Being able to calculate the expected revenue stream from feeding into the grid makes it easier for an individual to justify that investment.

351. The distributional impacts of any support measures need to be considered. Battery technology is still a substantial outlay, and so likely to be out of reach by lower-income households. Any support measures for battery roll-out would need to be carefully designed and allocated to ensure reliability benefits accrue across society.

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129 Roy Morgan. (2022, 18 October). *Solar Energy Systems on households have more than doubled since 2018 – now at nearly a third of all households (32.3 per cent)*. Roy Morgan website. Available at: https://www.roymorgan.com/findings/9091-solar-energy-systems-on-households-more-than-double-since-2018-now-at-nearly-a-third-of-all-households

130 Daniel Mercer. (2023, 30 March). Household battery uptake surges to record high amid market turmoil, rocketing prices. *ABC News*. Available at: https://www.abc.net.au/news/2023-03-30/australian-household-battery-uptake-surges-to-record-high/102160138

131 Essential Services Commission. (2023, 30 January). *Minimum feed-in tariff review 2023–24*. Engage Victoria website. Available at: https://engage.vic.gov.au/minimum-feed-in-tariff-review-202324

### *Financing options for investment in distributed storage and other distributed energy resources*

352. The government could explore options to provide upfront capital that is accessible across all household types, at all income levels for household battery storage (with or without solar). This could include low interest loans with repayment requirements linked to current household income.

353. This type of financing approach could be extended to other types of CER (such as smart devices), that could lower overall energy costs to consumers, offset network investment and provide significantly lower cost firming than grid scale batteries or fossil gas peaking.

354. The Rewiring Australia project is exploring financing options to facilitate household electrification at scale across all demographics.[132] The Rewiring Australia project sets out analysis that shows that, in the Australian context, financed electrification is anti-inflationary. It replaces inflationary fossil fuel prices with flat finance repayments for electrification and solar. The value of this to lower energy bills for households is further enhanced by the forecast drop in costs of batteries due to manufacturing scale.

### *Reducing soft costs for household battery and solar installation*

355. Uptake of batteries and solar systems could be supported through measures to reduce 'soft costs'. Soft costs are costs which sit between the product price and the final installed ready product in the home. These include regulations, standard install practices, rarity of the product installed, and industry training and development. Australia has a streamlined process for solar installation which has significantly lowered soft costs.

356. Government could undertake a study to identify opportunities for soft cost reduction for solar batteries and potentially other smart devices, where those costs are related to individualised trade experience variation, household types, regulation and compliance with the local network. It could set out how those reductions might be scaled nationwide in different household types and network environments.

### *Questions*

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|---|---|
| 53. | Should the government consider ways to create more investment certainty for local battery storage? If so, what technology should be looked at for this? |
| 54. | Should further thought be given to making upfront money accessible to all household types, at all income levels, for household battery storage or other types of CER? |
| 55. | Should government think about ways to reduce 'soft costs' (like the cost of regulations, sourcing products, and upskilling supplier staff) for installing local battery storage with solar and other forms of CER/DER storage? If so, what technology should be looked at? |

### *Smart metering – quality and access to data*

357. Better quality, and better access to, data is needed to facilitate uptake of distributed flexibility at scale. The Authority recently noted that "ideally, New Zealand would have a fully

[132] For more information, see: https://www.rewiringaustralia.org

digitised energy system in which key data could be seamlessly accessed and exchanged in real-time by authorised parties." Data from smart meters could be a central part of such a system. However, in practice it has been difficult for market participants to develop a smooth process for sharing data.

## WHAT IS ALREADY UNDERWAY

358. The Authority has recently consulted on issues around access to smart meter data for distributors and flexibility traders.[133] The consultation included proposals for timelines to shift to real-time provision of energy and power quality data for distribution businesses and flexibility aggregators. This information may enable better optimisation and more dynamic management of distribution networks and greater use of distributed flexibility. The Authority has suggested several improvements to the current system and is currently considering submissions.

## FURTHER MEASURES TO CONSIDER?

359. We are interested in views on whether there is a need for a wider regulatory review of critical data availability across the whole system, including the domains of the Commission and the Authority, so as to ensure that data availability is not a barrier to efficient flexibility markets developing.

### *Question*

| | |
|---|---|
| 56. | Is a regulatory review of critical data availability needed? If so, what issues should be looked at in the review? |

[133] Electricity Authority. (2022, December). *Issues paper: Updating the Regulatory Settings for Distribution Networks*. Available at: https://www.ea.govt.nz/projects/all/updating-regulatory-settings-for-distribution-networks/consultation/regulatory-settings-to-support-non-network-solutions-and-flexibility-services/

# PART 5: WHOLE-OF-SYSTEM CONSIDERATIONS

Part 5, **Whole of System Considerations** comprises Chapter 11 **Setting priorities and improving co-ordination** which explores whether there is a case for greater formal co-ordination of planning of the electricity system as a whole. There are trade-offs between maintaining security and reliability, and equity and affordability, as we transition.

This chapter considers challenges on how best to achieve balance across the – at times competing – objectives for the electricity system. It seeks feedback on priorities for government action, whether a new coordination function across the electricity system could play a useful role, and how to balance across the security and reliability, and equity and affordability objectives.

*Focus for Part 5 – Whole of System Considerations*

| | |
|---|---|
| **CHALLENGES** | • Clear government prioritisation of measures to support the energy transition<br>• Sufficient coordination of long-term planning for the energy system<br>• Balancing government policy objectives for the electricity system |
| **WORK ALREADY UNDERWAY** | • Development of the New Zealand Energy Strategy by the end of 2024 |
| **FURTHER POSSIBLE MEASURES TO CONSIDER** | • Clearer prioritisation of measures to address challenges<br>• Additional coordination and transparency measures<br>• Changes to clarify how the government's policy objectives should be balanced |

# 11 Setting priorities and improving coordination

## PRIORITISING ACROSS DEVELOPMENT OF MEASURES

360. This document considers many possible measures that could be used to support the electricity sector's transition. Many commentators urge action across the board,[134] and we agree that to achieve a transition to renewable electricity that addresses the challenges outlined in this paper, developing a number of support measures is likely to be warranted.

361. However New Zealand is a small country and, as support measures are developed, this will be carried out with finite funding and resources. Government agencies must prioritise across competing ambitions. This section asks what areas of focus the government should prioritise, in addition to anticipating changes driven by the Emissions Trading Scheme.

*Question*

| | |
|---|---|
| 57. | What measures do you consider the government should prioritise to support the transition? |

## INVESTMENTS AND SUPPORT ACROSS THE SECTORS

362. Our electricity system relies on a multitude of different parties each making their own investment and operational decisions based on their own assessments of costs and benefits, and all using different sources of information. All actors in the system respond to their own organisational, commercial and regulatory incentives. But, there is no active system architect, as such, to guide or coordinate the fragmented decisions of individual actors in a manner that best promotes system-level objectives.

363. In a period of rapid market, geopolitical and technological change, it may be difficult to coordinate all the different participants, whether government or private. If sufficient coordination doesn't occur between these actors, this could result in wasted investment.

364. Under current proposals for a future resource management system,[135] regional spatial strategies will see central government, local government and Māori working together, in consultation with the community, to identify how their region will grow, adapt and change over the next thirty-plus years. Regional spatial strategies will focus on significant issues and opportunities facing the relevant region. Whilst revised national policy statements (made under the current RMA) for renewable energy and transmission are in development, they are specific to generation and transmission. At present, there is no clear mechanism ensuring an

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134 For example, see Saul Griffith. (2022). *Electrify: An Optimist's Playbook for Our Clean Energy Future*. MIT Press. This 'detailed blueprint—optimistic but feasible—for fighting climate change while creating millions of new jobs and a healthier environment' contains recommendations for more renewable generation, transformed infrastructure and updated grids, and adapted households. For more information, see: https://mitpress.mit.edu/9780262545044/electrify/

135 Ministry for the Environment. (2022, 15 November). *Key components of our future resource management system*. Ministry for the Environment website. Available at: https://environment.govt.nz/what-government-is-doing/areas-of-work/rma/resource-management-system-reform/key-components-of-our-future-resource-management-system/

optimal pathway for meeting system-level objectives across the whole electricity sector – including generation, transmission and distribution networks, and more localised generation and demand response – across New Zealand as a whole or in specific regions.

365. In other jurisdictions, the relevant system operator has a function to set a roadmap to drive towards net-zero emissions and other climate change targets. For example:

- Since 2018, the Australian Energy Market Operator (AEMO) has had a new function to create an 'Integrated System Plan'[136] – a whole-of-system plan that provides an integrated roadmap for the efficient development of the National Electricity Market.
- In the UK, the Government is progressing the establishment of a 'Future System Operator' (FSO). Building on the existing capabilities and functions of the electricity system operator, the FSO would shape and plan the electricity and gas systems to support the future development of the electricity system.

366. A new coordination function could extend to making decisions about what investments can or cannot be made. For example, the relevant entity could have the right to authorise:

- whether developments occur in a single buyer market (described in Chapter 6)
- transmission developments within designated areas, as the Energy Corporation (EnergyCo) in New South Wales (NSW) can currently do.

*Question*

| | |
|---|---|
| 58. | Are there gaps in terms of information co-ordination or direction for decision-making as we transition towards an expanded and more highly renewable electricity system and meeting our emissions goals? Please provide examples of what you'd like to see in this area. |

## RENEWABLE ENERGY ZONES

367. Renewable energy zones (REZs) are an option to enable the coordinated development of multiple renewable energy projects alongside network infrastructure. REZ developments can provide benefits, including:

- addressing first mover disadvantage – by coordinating and developing a framework for connecting generators up front, before the development of transmission and/or distribution assets
- providing for the sharing of high connection costs between several connecting customers, over-time and with certainty
- increasing renewable generation through unlocking potential in regions with good renewable resources, but limited access to transmission and/or distribution networks.

136 Australian Energy Market Operator. (2023, June). *Integrated System Plan (ISP)*. AEMO website. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp

### *What are the issues a REZ could solve in New Zealand?*

368. In New Zealand, some areas are not well served by transmission or distribution networks due to sparse and spread-out populations and lower electricity demand, despite having significant renewable resource. Upgrades to, or development of new, transmission or distribution assets need to be funded by the connecting party. This can be a disincentive for any one party to go ahead with their generation investment. A REZ could be designed such that generators inside a REZ would receive guaranteed, unconstrained access to the national grid. This could help lower project finance costs. Similar approaches are being considered on the demand side through the GIDI Fund – for example, EECA's Regional Energy Transition Accelerator programme.

## WHAT IS ALREADY UNDERWAY?

369. Transpower has consulted on a national REZ framework and a Northland REZ pilot. In February to April 2022, Transpower consulted on a possible national REZ framework to understand the potential for REZs. Transpower also tested, in partnership with Northpower and Top Energy, the feasibility for a REZ in Northland. The Northland region is an example where there is high electricity generation developer interest. There are constraints on the fringes of the transmission and distribution networks in the region, but significant capacity is available on the national grid backbone. The REZ consultation raised some complex issues that Transpower are continuing to work through with government and regulatory stakeholders.

## WHAT ELSE MIGHT WE NEED TO CONSIDER?

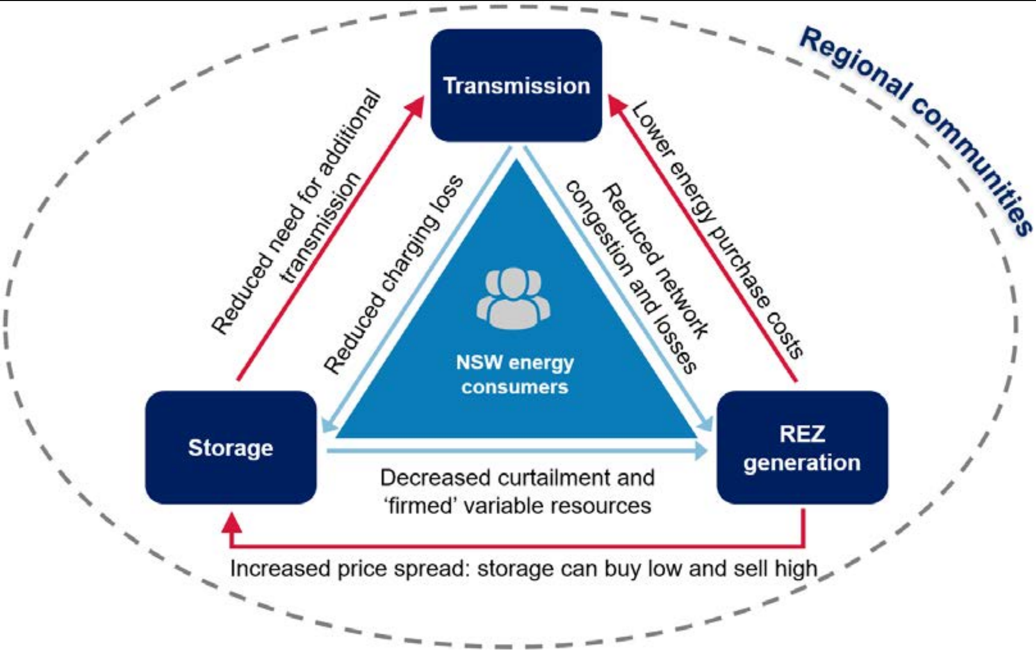
370. The NSW Government's initiatives for REZs are distinctive because they are paid for by a consumer levy and motivated by delivering lower electricity prices and timely investment in reliable new renewable generation.

371. In the NSW model, the costs of both long-term energy service agreements and renewable energy zone infrastructure are levied onto all consumers in NSW. In New Zealand, this approach would require ringfencing transmission costs chargeable under Transpower's transmission pricing methodology (regulating Transpower's charges for operating the national grid), because the benefits and timescales of the REZ transmission investments are system wide.

**Box 11: New South Wales (Australia) model of Renewable Energy Zones**

The NSW Government has developed an Electricity Infrastructure Roadmap[137] (NSW Roadmap) which is a plan to establish at least 12 GW of new renewable generation, and 2 GW of long-term storage, by 2030 to replace existing fossil fueled power stations as they retire, and to power new demand.

The NSW Roadmap coordinates the development of the state's solar and wind potential in REZs: where renewable generation is developed with enabling transmission and electricity storage infrastructure into a form of reliable, controllable electricity which can be stored and transmitted across NSW.




The NSW Roadmap and, the mechanisms that it coordinates, address specific problems in the transition to a renewable electricity system such as:

- delays to new generation investment due to capital costs including avoidable risks related to transmission connection and curtailment, and due to uncertainty about long term energy prices
- delays to commissioning new and expanded transmission capacity, due to near-term planning horizons and project-by-project consideration in the regulatory approval regime, and due to a lack of regulated funding for project development and risk.

NSW's EnergyCo acts as the designated 'Infrastructure Planner'. It plans and coordinates the delivery of REZs and priority transmission projects. These projects are designed to lower electricity costs by bringing renewable wind and solar electricity – which is the cheapest generation available – to consumers across NSW who pay for them. Projects are awarded by a 'Consumer Trustee'.

The role of NSW's EnergyCo and the Consumer Trustee (currently AEMO Services) were previously discussed in Chapter 3 (see Box 3) in relation to capacity measures. The following explains their roles in more detail in the context of REZs.

[137] New South Wales Government. (2023, June). *Electricity Infrastructure Roadmap*. NSW Climate and Energy Action website. Available at: https://www.energy.nsw.gov.au/nsw-plans-and-progress/major-state-projects/electricity-infrastructure-roadmap

The Consumer Trustee runs competitive tenders for renewable generation, long duration storage and firming. Successful tenders are awarded Long Term Energy Service Agreements (LTESA) which are 'swap options' (or swaptions) – providing long-term energy price guarantees. Consumers only face costs under LTESAs when they benefit from reduced energy prices (ie, when wholesale market prices fall below a pre-agreed level). However, generation developers can agree low-cost project finance because they have price certainty, while being able to benefit when wholesale market prices are high.

EnergyCo (as the Infrastructure Planner) facilitates the coordinated and accelerated development of transmission and energy storage infrastructure necessary for supply security. 'REZ network infrastructure projects' are planned by the EnergyCo and tendered by the Consumer Trustee. Like LTESAs, REZ network infrastructure projects are awarded to deliver lower prices and reliable supply to consumers. For this reason, costs are levied onto all consumers in NSW and not just within the region where the projects are located.

Priority transmission projects are identified by the Australian Energy Market Operator in their Integrated System Plan as projects outside REZs necessary to maintain energy supply and security.

REZs, LTESAs, REZ network infrastructure projects and priority transmission projects are built on similar foundations to the New Zealand electricity market: the Australian NEM is a security-constrained economic pool for balancing electricity supply and demand, like the New Zealand electricity wholesale market. The Australian Energy Regulator sets prices for, and approves new investments in, natural monopoly transmission and distribution lines. This follows objectives similar to those that apply under Part 4 of the New Zealand *Commerce Act 1986* administered by the Commerce Commission (Commission).

The NSW government is exploring how similar infrastructure planning and coordination could be used to create 'urban REZs'. These involve electricity distribution acting as balancing networks, where the network produces net generation of reliable, controllable electricity from privately owned local solar and wind generation in community battery and other storage technologies.

### *Deploying the REZ model in New Zealand – transmission*

372. A REZ model in New Zealand could accelerate investment in new renewable electricity generation, or electrification. However, a REZ model or the broader NSW EnergyCo central planning model does not fit easily within our system settings of competition in the generation market and open access to the transmission network.

373. A more flexible regulatory system could allow for greater ability to provide transmission interconnection investment in time to meet increasing generation and electrification needs. We understand that the Commission is considering relevant features of the system in its 2023 Input Methodologies Review (IM Review). We propose to wait for the outcome of the IM Review, and review the extent to which it has addressed transmission investment challenges that might otherwise make REZs attractive.

### *Deploying the REZ model in New Zealand – distribution networks*

374. There are likely to be some advantages if a REZ considers energy investment at a local distribution level. It could be one way to address first mover disadvantage for customers connecting to distribution networks, whether for new renewable distributed generation (DG) or to support large load (see Chapter 8 for discussion of this issue). Efficient investment in distribution network and connection assets could be identified within a local REZ to unlock

investment in renewable DG projects by multiple developers or new or expanded connections for large load customers in a region.

375. A local REZ could also consider the future energy needs and perspectives of local communities, including iwi. It could increase affordability for consumers by providing scope to consider how investments in a region (for example in renewable DG or storage solutions) could be optimised to reduce local costs and provide for community energy needs most efficiently.

376. Another example of regional energy planning from overseas is the concept of introducing a ‘Regional System Planner’ (RSP) to ensure accountability for regional energy system planning.[138] The RSP could work across energy networks and local authorities to provide greater co-ordination, maximise efficient planning across different types of energy sources and consider differing regional needs.

### *Question*

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|---|---|
| 59. | Are there significant advantages in adopting a REZ model, or a central planning model (like the NSW EnergyCo), to coordinate electricity transmission investment in New Zealand?<br><br>Would a REZ model for local electricity distribution be an effective means of addressing first mover disadvantage with connecting to electricity distribution networks? |

### *More coordination and transparency of information*

377. Another way to help improve system-level objectives for the electricity system may involve government, in addition to improving its information base, better supporting co-ordination and use of information by the market.

378. The Electricity Authority, in its review of wholesale market competition, suggested that MBIE produce a new ‘*Annual Electricity Generation Investment Opportunities*’ report to enable informed market decision-making, by outlining opportunities for generation investment. We think there is merit in this proposal. A report of this kind could leverage or extend MBIE’s existing role in preparing regular electricity demand and generation scenarios, which provide an independent starting point for transmission investment planning by Transpower.

379. Some policy options being considered by government (such as initiatives for supporting firming generation) require more active co-ordination of information inputs across the electricity market. This document includes examples where such wider system information would be needed to guide future allocation decisions, such as the Australian Capacity Investment Scheme (discussed in Chapter 3). Improved whole-of-system information would better enable demand response proposals to be evaluated against generation and storage options when determining capacity need.

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[138] Ofgem. (2023). *Consultation: Future of local energy institutions and governance*. Available at: https://www.ofgem.gov.uk/publications/consultation-future-local-energy-institutions-and-governance

### *Question*

| 60. | Should MBIE regularly publish opportunities for generation investment to enable informed market decision-making? |
|---|---|

### *Balancing the government's policy objectives*

380. As noted above, this *Measures for Transition to an Expanded and Highly Renewable Electricity System* issues paper aligns with the above four objectives in the New Zealand Energy Strategy and focuses on how to ensure the right measures are in place to achieve the sustainability goal of a renewable electricity system, whilst ensuring a secure, reliable and affordable supply.

381. There are trade-offs between maintaining security and reliability, and equity and affordability, as we transition. This chapter considers challenges in how best to achieve balance across the – at times competing – objectives for the electricity system.

382. The Introduction explained that this paper relies on the World Energy Council's trilemma definitions:

- Energy security – this measures a nation's capacity to meet current and future energy demand reliably (across different time periods), and withstand and bounce back swiftly from system shocks with minimal disruption to supplies. This dimension covers the effectiveness of management of domestic and external energy sources, as well as the reliability and resilience of energy infrastructure.
- Energy equity – this assesses a country's ability to provide universal access to reliable, affordable, and abundant energy for domestic and commercial use. This dimension captures basic access to electricity and clean cooking fuels and technologies, access to prosperity-enabling levels of energy consumption, and affordability of electricity, gas, and fuel.
- Environmental sustainability of energy systems – this represents the transition of a country's energy system towards mitigating and avoiding potential environmental harm and climate change impacts. The dimension focuses on productivity and efficiency of generation, transmission and distribution, decarbonisation, and air quality.

383. Equity and affordability, and the related role of cost-reflective pricing, requires consideration of:

- whether pricing in the wholesale electricity market reflects the costs to generate electricity and invest in new generation
- whether charges for transmission and distribution networks fairly reflect the cost of transporting electricity, a fair share of the cost of new network connections and investments, and signal investment needs, and incentivise some consumers to change how and when they use electricity

- whether industrial users are incentivised to enable emissions reductions and provide demand response – when needed – to lower the cost of supply shortages
- how networks and customers can make use of new innovative technologies to use electricity in a smarter way – for example, by using different appliances and shifting load in a way that overall, reduces costs to everyone.

384. Cost reflective pricing is not an end point, and some pricing in the electricity system involves prices that are above cost to supply (such as the wholesale market) or that involve cross subsidies (such as equivalent lines charges across an urban and semi-rural area of a lines network).

### *Balancing reliability and affordability*

385. There are fundamental trade-offs between reliability of electricity supply and the cost of achieving it, with affordable prices to consumers, as we transition. Chapter 9 above considers whether the sustainability objective is appropriately reflected in the objectives set for our system's regulators. This section considers the balance across reliability and affordability.

386. Reliability can generally be improved by investing in more generators, lines and other assets used to supply electricity (so that the power is more likely to stay on if any assets fail or are disrupted by bad weather or other hazards). Reliability can also be improved by building stronger assets to withstand severe weather, or to protect them from floods, cyber-attacks, and other hazards.

387. The cost of any investment is usually passed on to some or all electricity customers. Consumer interests are generally best served when the extra benefit gained from the improved reliability is more than the cost of that improvement. In practice, this means that consumers always face some remaining risk of interrupted electricity supply, as it is generally not economically feasible to attain 100 per cent reliable supply, it would simply cost too much. Also, the cost of improving reliability may be very different for consumers across the country – those in urban areas often enjoy a more reliable electricity system at lower cost per consumer, than customers in remote rural areas.

### *Is cost reflective pricing appropriate for all aspects of electricity pricing?*

388. The regulatory policies and commercial practices that currently prevail in the electricity industry generally favour aiming for cost-reflective pricing. This has been considered desirable, because cost reflective pricing is considered to drive efficient decisions by consumers, generators and investors in new generation that lead to the 'right levels of consumption', and the 'right investments, in the right place, at the right time'. This concept extends to dynamic efficiency, where innovation and investments keep costs lower over time.

389. Theoretically, cost reflective pricing underpins:

- The market design for the wholesale electricity market. Spot prices are very deliberately derived through a process that ensures the price for a unit of electricity at any given half hour, and any given location on the transmission grid, reflects the extra cost of supplying that generation at that time and to that location.[139]

- Current approaches to allocating costs for transmission and distribution services. Nonetheless, there can be significant variation in how charges are calculated across different distributors: for example, most networks do not seek to reflect cost differences between urban and rural consumers, or residential and small business consumers, but many do offer some plans with prices that vary by time of day.

390. Time-varying prices (at the distribution and retail levels) are usually closer to being cost-reflective, and so efficiency-enhancing, if customers respond by shifting some consumption away from peak demand periods (when generation is usually more expensive, and the transmission and distribution networks are working close to capacity).

391. As we transition, we may need to actively consider to what extent it may be appropriate to diverge from cost-reflective pricing to balance other parts of the energy trilemma. While cost-reflective pricing is generally favoured on efficiency grounds, it is reasonable to ask whether, or to what extent, electricity pricing should also be influenced by sustainability, reliability affordability or equity objectives. For example, we can ask:

- To achieve energy affordability and equity, should we consider some pricing that is below the cost to supply (such as retail tariffs that are set across the year and do not fluctuate with changing wholesale power prices) and transmission and distribution prices that allow for cross subsidies (when one party pays above cost, so another can pay below cost)?
- Could prices be lower for industries converting from coal to electric boilers, for public EV charging stations that help electrify our transport sector, or could charges for the transmission grid or distribution networks be more evenly spread than the current charging systems, if that would better serve the Government's emission reduction targets and plans?
- Could electricity prices be reduced for households suffering energy hardship, if that were more equitable – to better achieve a just transition to a low-emissions economy?

392. It is also reasonable to ask whether, or to what extent equity and affordability objectives could be better addressed outside of the electricity regulatory system, such as through income support measures such as targeted energy affordability payments or similar, and via New Zealand's Emissions Trading Scheme.

393. A number of workstreams across government aim to address this challenge. Box 12 outlines workstreams considering and developing mechanisms to support electricity equity and affordability.

[139] As noted in Part 2 above, our wholesale market is cost-reflective only in as much as generator offers reflect cost, and competition may decline as we transition to a higher share of renewable electricity.

| Box 12: Energy affordability |
|---|
| A number of workstreams across government aim to address the challenge of energy affordability, including the development of the Equitable Transitions Strategy,[140] the Energy Hardship Expert Panel's engagement for a report back to Government, the Support for Energy Education in Communities Programme and the Winter Energy Payment.<br><br>The Authority's *Consumer Care Guidelines* advise retailers on how to support customers who may be struggling to pay electricity bills.<br><br>The Consumer Advocacy Council (CAC) has also been established to be an independent advocate for residential and small business electricity consumers in New Zealand. The CAC was established following a recommendation made by the independent 2018-2019 Electricity Price Review. |

394. It is generally accepted that:

- markets achieve lower prices, in the long run, if efficient pricing signals are used – incentivising generation, network, and technology investments in the right place and at the right time, that bring down prices for everyone
- redistributional mechanisms can work alongside markets, to achieve desired social outcomes (such as more affordable electricity for lower-income households, or for households in regions that face higher charges).

395. However, current measures in place offer a similar level of support to all recipients (such as the Winter Energy Payment), and do not provide extra support for customers in higher cost areas to ensure they do not pay more than customers in lower cost areas. Whether this is a significant concern will depend on the extent of difference between high-priced regions compared to the average regional cost. Also, targeted redistributional schemes tend to have higher administrative costs which may exceed any savings gained through targeting.

396. How to achieve the right balance across maintaining security and reliability, and equity and affordability, as we transition, is an important question. It highlights how policy and regulatory objectives, whether implicit or explicit, can affect real-world outcomes.

### *Questions*

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| 61. | How should the government balance the aims of sustainability, reliability and affordability as we transition to a renewable electricity system? |
| 62. | To what extent should wholesale, transmission, distribution or retail electricity pricing be influenced by objectives beyond the (affordability-related) efficiencies achieved by cost-reflective pricing, such as sustainability, or equity? |
| 63. | Are the current objectives for the system's regulators set in law (generally focusing on economic efficiency) appropriate, or should these also include more focussed objectives of equity and/or affordability? |

[140] MBIE. (2023, June). *Equitable Transitions Strategy*. MBIE website. Available at: https://www.mbie.govt.nz/business-and-employment/economic-development/equitable-transitions-strategy/

# PART 6: RECAP OF QUESTIONS

Your submission may respond to any or all of the questions. Where possible, please explain the reasons for your answer. Include relevant evidence to support your views, for example references to independent research, facts and figures.

| PART 1: GROWING RENEWABLE GENERATION | |
|---|---|
| 1. | Are any extra measures needed to support new renewable generation during the transition?<br>Please keep in mind existing investment incentives through the energy-only market and the ETS, and also available risk management products. Any new measures should add to (and not undermine or distort) investment that could occur without the measures. |
| 2. | If you think extra measures are needed to support renewable generation, which ones should the government prioritise developing and where and when should they be used? What are the issues and risks that should be considered in relation to such measures? |
| 3. | If you don’t think further measures are needed now to support new renewable generation, are there any situations which might change your mind? When and why might this be? |
| 4. | Do you think measures could be needed to support new firming/dispatchable capacity (resources reliably available when called on to generate)? If yes, which kind of measures? What needs do you think those measures could meet and why? |
| 5. | Are any measures needed to support storage (such as battery energy storage systems or BESS) during the transition? If yes, what types of measures do you think should be considered and why? |
| 6. | If you answered yes to question 4 or 5 above, should the support be limited to renewable generation and renewable storage technologies only or made available across a range of other technologies?<br>Keep in mind that fossil fuels are generally the cheapest option for firming, though this may change over time as renewable options (particularly batteries) become more efficient and affordable. |
| 7. | If you answered yes to question 6 above, what are the issues and risks with this approach? How could these risks and issues be addressed? |
| 8. | Are any measure(s) needed to support existing or new fossil gas fired peaking generation, so as to help keep consumer prices affordable and support new renewable investment? |
| 9. | If you answered yes to question 8 above, what measures should be considered and why? What are the possible risks and issues with these measures? |
| 10. | If you answered yes to question 8 above, what rules would be needed so that fossil gas generation remains in the electricity market only as long as needed for the transition, as part of phase down of fossil gas? |

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| 11. | Are there any issues or potential issues relating to gas supply availability during electricity system transition that you would like to comment on? |
| 12. | Do you agree that specific measures could be needed to support the managed phasedown of existing fossil fuel plants, for security of supply during the transition? |
| 13. | If you answered yes to question 12 above, what measures do you think could be appropriate and why? What conditions do think you should be placed on plant operation?<br>For example, do you have any views on whether there should be a minimum notice period for reductions in plant capacity, and/or for placing older fossil fuel plant in a strategic reserve? |
| 14. | If you answered yes to question 12 above, what are the issues and risks with these measures and how do you think these could be addressed? |
| 15. | What types of commercial arrangements for demand response are you aware of that are working well to support industrial demand response? |
| 16. | What new measures could be developed to encourage large industrial users, distributors and/or retailers to support large-scale flexibility? |
| 17. | Do you have any views on additional mechanisms that could be developed to provide more information and certainty to industry participants? |
| **PART 2: COMPETITIVE MARKETS** | |
| 18. | Do you agree that the key competition issue in the electricity market is the prospect of increased market concentration in flexible generation, as the role of fossil fuel generation reduces over time? |
| 19. | Aside from increased market concentration of flexible generation, what other competition issues should be considered and why? |
| 20. | What extra measures should or could be used to know whether the wholesale electricity market reflects workable competition, and if necessary, to identify solutions? |
| 21. | Should structural changes be looked at now to address competition issues, in case they are needed with urgency if conduct measures prove inadequate? |
| 22. | Is there a case for either vertical separation measures (generation from retail) or horizontal market separation measures (amending the geographic footprint of any gentailer) and, if so, what is this? |
| 23. | Are measures needed to improve liquidity in contract markets and/or to limit generator market power being used in retail markets? If yes, what measures do you have in mind, and what would be the costs and benefits? |
| 24. | Should an access pricing regime be looked at more closely to improve retail competition (beyond the flexibility access code proposed by the Market Development Advisory Group or MDAG)? |

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| 25. | What extra measures around electricity market competition, if any, do you think the government should explore or develop? |
| 26. | Do you think a single buyer model for the wholesale electricity market should be looked at further? If so, why? If not, why not? |
| **PART 3: NETWORKS FOR THE FUTURE** | |
| 27. | Do you consider that the balance of risks between investing too late and too early in electricity transmission may have changed, compared to historically? If so, why? |
| 28. | Are there any additional actions needed to ensure enough focus and investment on maintaining a resilient national grid? |
| 29. | Do you agree we have identified the biggest issues with existing regulation of electricity distribution networks? |
| 30. | Are there pressing issues related to the electricity distribution system where you think new measures should be looked at, aside from those highlighted in this document? How would you prioritise resolving these issues to best enable the energy transition? |
| 31. | Are the issues raised by electricity distributors in terms of how they are regulated real barriers to efficient network investment?<br>Please give reasons for your answer. Is there enough scope to address these issues with the current ways distributors are regulated? If not, what steps would you suggest to address these issues? |
| 32. | Are there other regulatory or practical barriers to efficient network investment by electricity distributors that should be thought about for the future? |
| 33. | What are your views on the connection costs electricity distributors charge for accessing their networks? Are connection costs unnecessarily high and not reflective of underlying costs, or not? If they are, why do you think this is occurring? |
| 34. | If you think there are issues with the cost of connecting to distribution networks, how can government deliver solutions to these issues? |
| 35. | Would applying the pricing principles in Part 6 of the Code to new load connections help with any connection challenges faced by public EV chargers and process heat customers? Are there other approaches that could be better? |
| 36. | Are there any challenges with connecting distributed generation (rather than load customers) to distribution networks? |
| 37. | Are there different cost allocation models addressing first mover disadvantage (when connecting to distribution networks) which the Electricity Authority should explore, potentially in conjunction with the Commerce Commission? |
| 38. | Should the Electricity Authority look at more prescriptive regulation of electricity distributors' pricing? What key things would need to be looked at and included in more prescriptive pricing regulation? |

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| 39. | Do current arrangements support enough co-ordination between the Electricity Authority and the Commerce Commission when regulating electricity distributors? If not, what actions do you think should be taken to provide appropriate co-ordination? |
| 40. | Will the existing statutory objectives of the Electricity Authority and Commerce Commission adequately support key objectives for the energy transition? |
| 41. | Should the Electricity Authority and/or the Commerce Commission have explicit objectives relating to emissions reduction targets and plans set out in law? If so,<br>• should those objectives be required to have equal weight to their existing objectives set in law?<br>Why and how might those objectives affect the regulators' activities? |
| 42. | Should the Electricity Authority and/or the Commerce Commission have other new objectives set out in law and, if so, which and why? |
| 43. | Is there a case for central government to direct the Commerce Commission, when dealing with Electricity Distributors and Transpower, to take account of climate change objectives by amending the Commerce Act and/or through a Government Policy Statement (GPS)? |
| 44. | If you answered yes to question 43, please explain why and indicate:<br>• What measures should be used to provide direction to the Commerce Commission and what specific issues should be addressed?<br>• How would investment in electricity networks be impacted by a direction requiring more explicit consideration of climate change objectives? Please provide evidence. |
| **PART 4: RESPONSIVE DEMAND AND SMARTER SYSTEMS** | |
| 45. | Would government setting out the future structure of a common digital energy infrastructure (to allow trading of distributed flexibility) support co-ordinated action to increase use of distributed flexibility? |
| 46. | Should central government see how demonstrations and innovation to help inform how trade of flexibility evolves in the New Zealand context, before providing direction to support trade of distributed flexibility? If yes, how else could government support the sector to collaborate and invest in digitalisation now? |
| 47. | Aside from work already underway, are there other areas where government should support collaboration to help grow and develop flexibility markets and improve outcomes? If yes, what areas and actions are a priority? |
| 48. | Could co-funding for procurement of non-network services help address barriers to uptake of non-network solutions (NNS) by electricity distributors? |
| 49. | Would measures to maximise existing distribution network use and provide system reliability (such as dynamic operating envelopes) help in New Zealand? If yes, what actions should be taken to support this? |

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| 50. | What do you think of the approaches to smart device standards and cyber security outlined in this document? Are there other issues or options that should be looked at? |
| 51. | Do you think government should provide innovation funding for automated device registration? If not, what would best ensure smart devices are made visible? |
| 52. | Are extra measures needed to grow use of retail tariffs that reward flexibility, so as to support investment in CER and improved consumer choice and affordability? |
| 53. | Should the government consider ways to create more investment certainty for local battery storage? If so, what technology should be looked at for this? |
| 54. | Should further thought be given to making upfront money accessible to all household types, at all income levels, for household battery storage or other types of CER? |
| 55. | Should government think about ways to reduce 'soft costs' (like the cost of regulations, sourcing products, and upskilling supplier staff) for installing local battery storage with solar and other forms of CER/DER storage? If so, what technology should be looked at? |
| 56. | Is a regulatory review of critical data availability needed? If so, what issues should be looked at in the review? |
| **PART 5: WHOLE-OF-SYSTEM CONSIDERATIONS** | |
| 57. | What measures do you consider the government should prioritise to support the transition? |
| 58. | Are there gaps in terms of information co-ordination or direction for decision-making as we transition towards an expanded and more highly renewable electricity system and meeting our emissions goals? Please provide examples of what you'd like to see in this area. |
| 59. | Are there significant advantages in adopting a REZ model, or a central planning model (like the NSW EnergyCo), to coordinate electricity transmission investment in New Zealand?<br>Would a REZ model for local electricity distribution be an effective means of addressing first mover disadvantage with connecting to electricity distribution networks? |
| 60. | Should MBIE regularly publish opportunities for generation investment to enable informed market decision-making? |
| 61. | How should the government balance the aims of sustainability, reliability and affordability as we transition to a renewable electricity system? |
| 62. | To what extent should wholesale, transmission, distribution or retail electricity pricing be influenced by objectives beyond the (affordability-related) efficiencies achieved by cost-reflective pricing, such as sustainability, or equity? |
| 63. | Are the current objectives for the system's regulators set in law (generally focusing on economic efficiency) appropriate, or should these also include more focussed objectives of equity and/or affordability? |

# List of Abbreviations

| | |
|---|---|
| **AEMO** | Australian Energy Market Operator |
| **BCG** | Boston Consulting Group |
| **BEIS** | UK Department for Business, Energy and Industrial Strategy |
| **BESS** | Battery energy storage system |
| **Capex** | Capital expenditure |
| **CCGT** | Combined cycle gas turbine |
| **CCRA** | *Climate Change Response Act 2002* |
| **CER** | Household level consumer energy resources |
| **CfD** | Contract for difference |
| **Code** | *Electricity Industry Participation Code 2010* |
| **DER** | Large scale distributed energy resources |
| **EECA** | Energy Efficiency and Conservation Authority |
| **ERP** | Emissions Reduction Plan |
| **ETS** | New Zealand Emissions Trading Scheme |
| **EV** | Electric vehicle |
| **FIT** | Feed-in tariff |
| **GPS** | Government Policy Statement |
| **GW** | Gigawatt – 1,000 megawatts (MW) |
| **HVDC** | High voltage direct current – The HVDC inter-island link connecting the North and South Islands |
| **IMs** | Input methodologies, set under Part 4 of the *Commerce Act 1986* |
| **LTESA** | Long Term Energy Service Agreement – a form of agreement that supports uptake of renewables and storage capacity in the New South Wales electricity market |
| **MBIE** | Ministry of Business, Innovation and Employment |
| **MDAG** | Market Development Advisory Group |
| **MW** | Megawatt |
| **MWh** | Megawatt hour |

**NAP** National Adaptation Plan

**NEM** National Electricity Market in Australia

**NNS** Non-network solutions

**OCGT** Open cycle gas turbine

**Opex** Operational expenditure

**PPA** Power purchase agreement

**PV** Photovoltaic – a type technology used in solar panels

**RCP** Regulatory Control Period – a five-year regulatory period for Commerce Commission regulation of Transpower. RCP4 is from 2025 to 2030.

**REZ** Renewable Energy Zone

**RMA** *Resource Management Act 1991*

**TPM** Transmission Pricing Methodology

# Glossary of electricity terms used

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|---|---|
| Ancillary service | Services required by the System Operator to enable them to maintain the integrity and stability of the transmission system as well as the power quality |
| Baseload generation | Generation that is designed to be operated near/or at full capacity most of the time except for maintenance, up to the maximum capacity allowed by its water, steam or fuel supply. |
| Behind the meter injection | Generation that is injected or produced at a customer's site, that is usually metered separately from what a retailer sells them |
| Demand response | Responses to reduce network demand |
| Discretionary demand | Demand that can be more easily (centrally) controlled or reduced, eg ripple control |
| Distributed flexibility | All types of demand-side flexibility, demand response and flexibility from distributed generation and batteries. It can include arrangements for large users to reduce their demand, use of batteries to meet users' needs 'behind the meter' or supply energy into networks, or aggregated control of CER in response to supply and demand (eg, supply of household solar into the network or control of EV charging). |
| Distribution network | Local, low voltage networks that distribute electricity from the national grid to end consumers |
| Electrification | Changing energy processes so that they are supported by electricity, rather than other energy sources (eg, fossil gas) |
| Fast start | Generation that, if it is not running, when called on is able to start immediately or in a very short time (eg within minutes). |
| Firm capacity, firming or dispatchable capacity | Generation that is reliably available when called on or dispatched ie is able to provide 'firm' or steady generation output |
| Futures | A financial product sold to market participants to manage risk that obligates parties to buy or sell an asset at a predetermined future date and price |
| Gentailer | A larger, vertically integrated generator-retailer |
| Grid-presented demand | Demand or load as measured at the national or high voltage grid |

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|---|---|
| Headroom in the supply stack | How much supply (generation) is available (not dispatched) while current demand is being met |
| Hedge | Alternative name for futures product |
| Hydro firming | The use of hydro in the firming role |
| Intermittent generation | Generation that is subject to variable or unpredictable fuel input, usually due to weather and can only run some of the time, eg solar or wind |
| Large scale flexibility | Demand response from distributed or grid connected large industrial energy consumers, including changes in demand in response to price signals, pre-contracted demand reductions, and 'behind the meter' injection or battery dispatch. |
| Long dated futures | A futures product or forward contract with a settlement date longer than one year ahead, and possibly as far away as 10 years |
| Marginal cost pricing | Where the price of a product is to equal the extra cost of producing an extra unit of output |
| Off-peak hedge | A hedge priced to apply mainly outside of peak or high demand periods |
| Option | A type of hedge or financial contract that is activated when certain conditions are met |
| Peaking generation | Generation that usually operates only for minutes or hours each day, during the sharpest demand peaks |
| Ripple control | An older technology that responded to a signal sent by networks to disable or enable customer load (usually hot water) during peak demand, which was priced on a cheaper tariff |
| Settlement price | The price at which an asset closes or of which a derivatives contract will reference at the end of each trading period |
| Shaped hedge product | A hedge or futures product that has a profile that more accurately reflects changes in load or demand |
| Slow-start generation | Generally fossil fuelled generation that takes several hours once started to reach operating efficiency |
| Strike price | The price for electricity in the hedge or futures contract. A party to a hedge or futures contact is either paid or must pay the difference between the strike and the 'reference price' – a measure of the market or spot price for electricity, depending on whether they are the issuer or purchaser of the contract |

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| System Operator | Operates the national (high voltage) grid. Defined in legislation as Transpower |
| Thermal plant | Generation plant that operates by burning a fuel such as fossil gas or coal (fossil fuels) to create heat which turns a turbine or creates steam, or both, in order to produce electricity |
| Trading period | The time when a settlement price is set. In the electricity market this traditionally was each half hour but under real time pricing it is a shorter period. With futures markets the trading period may be monthly, quarterly or yearly depending on the product |
| Virtual Power Plants (VPPs) | The aggregation of a number of separate, normally small, generators (which may be behind the meter) into a larger 'virtual plant' by a party known as an aggregator who will sell that energy into the market |

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