

Future Security and Resilience roadmap

Update

27/10/2026

Executive summary

The Electricity Authority Te Mana Hiko (Authority) is committed to promoting the future security and resilience of New Zealand's power system by proactively refining industry rules to support greater electrification that will enable better outcomes for consumers.

New Zealand's power system is transitioning from one dominated by a relatively small number of large traditional power stations to a more diverse system with increasing levels of solar, wind, and battery systems. Many of these technologies connect to the power system using power electronic inverter technology. Inverter technology tends to behave less predictably compared to traditional power stations because it uses electronic controls instead of spinning rotors.

At the same time, the growing uptake of distributed energy resources (DER) and flexible demand is increasing the complexity of power system operation and changing power flows throughout the power system. These developments introduce new technical challenges that require changes to how the power system is planned, operated, and regulated.

The purpose of the Authority's [Future Security and Resilience \(FSR\) programme](#) is to ensure the power system remains secure and resilient as New Zealand transitions towards a more electrified economy with an increasing proportion of wind and solar generation. The FSR programme is focused on the real-time or near real-time operation of the power system, including maintaining system stability, balancing supply and demand, and ensuring electricity continues to meet the needs and expectations of consumers and market participants.

The [FSR roadmap](#), originally published in 2022, set out a 10-year programme of work to address 10 emerging opportunities and challenges to the power system. The System Operator was tasked with developing this roadmap in response to the [Government's 2019 Electricity Price Review](#) recommending that the Authority examine the security and resilience of New Zealand's electricity supply.

The FSR roadmap highlights key milestones, and the sequence of activities required to address the transition to a more decentralised and increasingly intermittent and inverter-based power system. As the programme has progressed, the Authority has broadened its focus to consider challenges and opportunities across the wider power system, including the growing role of DER services and consumer participation.

The purpose of this document is to provide an update on the activities published in the original 2022 FSR roadmap. The update reflects significant developments in the power system and the Authority's work programme since the roadmap was first published.

This document:

- updates descriptions and implementation timelines across most of the existing activities.
- incorporates the Future System Operation (FSO) workstream¹, which was not included in the original version of the roadmap.

The Authority will continue to monitor system conditions and emerging risks and periodically review the FSR roadmap. Where evidence indicates that earlier intervention is required, the timing and prioritisation of regulatory work will be reconsidered. The Authority will publish further updates where material changes to roadmap priorities, activities, or timeframes are identified.

¹ The Future System Operation (FSO) workstream was initiated by the Authority under the [Future Security and Resilience \(FSR\) programme](#) in 2023. This was in response to stakeholder feedback on the need for a coordinated approach to the evolution of power system operation in the coming decades.

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1 Purpose

- 1.1 The purpose of this document is to provide an update on the activities set out in the Authority's original [Future Security and Resilience \(FSR\) roadmap published in 2022](#). It also outlines reasons for revised timelines for selected activities.
- 1.2 Since the roadmap was published, changes in the power system and the pace of the energy transition have altered priorities and implementation timeframes. Our work programme has evolved alongside the power system to include new issues that have emerged and address issues that are becoming more urgent than initially anticipated.
- 1.3 This update also incorporates the Future System Operation (FSO) workstream and associated [Distribution System Operation \(DSO\) roadmap](#) into the FSR roadmap, reflecting the interdependencies between these workstreams and the need for a more coordinated approach to future power system operation.

2 Background

- 2.1 The FSR programme was established in 2021 to ensure New Zealand's power system remains secure and resilient as the electricity sector evolves. The programme takes a forward-looking approach to enabling new technologies, addressing security and resilience risks, and building a power system that is reliable, flexible, and consumer focused. As the electricity sector continues to evolve, it is critical that the Authority anticipates future challenges and enables a smooth transition to a more electrified economy.
- 2.2 The FSR programme considers security as the ability of the power system, under normal conditions, to withstand disturbances and maintain steady and stable electricity supply. Resilience is the ability of the power system to quickly recover from disturbances and restore stable operation in response to a variety of expected and unexpected events.
- 2.3 The FSR programme forms part of the Authority's broader work to support the energy transition. It has strong links with other Authority programmes, including the Authority's work examining wholesale market operation under 100 percent renewable electricity generation and the *Updating the regulatory settings for electricity distribution networks*² programme. These programmes address complementary aspects of the increasing complexity of power system operation.
- 2.4 The FSR programme was developed in three phases.
 - (a) [Phase 1](#), completed in late 2021, identified key challenges and opportunities associated with the transition to a more electrified, low-emissions power system. These included the increasing penetration of inverter-based resources³ (IBR), such as wind, solar, and battery energy storage systems (BESS), and the declining role of large synchronous⁴ generators that have historically provided essential system services.
 - (b) [Phase 2](#), completed in August 2022, translated these findings into a 10-year work programme structured around the following 10 outcome areas in a roadmap:

² This programme ensures that regulatory settings relevant to the electricity distribution sector support the transition to a low-emissions energy system, while promoting competition, reliable supply, and efficient outcomes in the long-term interests of consumers.

³ The increasing penetration of inverter-based resources is challenging because it reduces the share of traditional power stations with spinning generators, also known as synchronous generators, leading to lower system inertia and new challenges for maintaining grid stability.

⁴ Synchronous generators have traditionally helped keep the electricity system stable by naturally supporting power system frequency and voltage. As more generation comes from wind, solar, and other inverter-based technologies, fewer of these large generators are operating. This means the grid has less of the stability support it has historically relied on, making it more challenging to maintain a secure and reliable power system, especially during faults or sudden changes in supply and demand.

Table 1: FSR Roadmap opportunities and challenges.

Opportunities and challenges	Timeframe	Priority
 Enabling DER services for efficient power system operations	3-7 years	● Medium
 Visibility and observability of DER	3-7 years	● Medium
 Coordination of increased connections	0-3 years	● High
 Balancing renewable generation	3-7 years	● Low
 Managing reducing system inertia	7-10 years +	● Low
 Operating with low system strength	3-7 years	● Medium
 Accommodating future changes within technical requirements	0-3 years	● High
 Leveraging new technology to enhance ancillary services	Enduring	● Medium
 Maintaining cyber security	Enduring	● High
 Growing skills and capabilities of the workforce	Enduring	● High

 Rise of Distributed Energy Resources
  Changing generation portfolio
  Foundational opportunities and challenges

(c) Phase 3, which is currently underway, focuses on delivering the 10-year work programme set out in the FSR roadmap.

- 2.5 The original roadmap anticipated an increasing penetration of IBRs and investment in utility-scale BESS. Since the roadmap was published, this trend has materialised. The share of generation from IBR sources has increased significantly, and Transpower's [connection pipeline](#) currently includes approximately 90 projects that could add more than 16,000 megawatts (MW) of new generation capacity in the coming years. Uptake of DER such as rooftop solar, BESS, and electric vehicles (EV) has continued to grow, although at a slower pace than was anticipated when the roadmap was first published.
- 2.6 These developments are increasing the complexity of power system operation and accelerating many of the technical challenges identified in Phase 1. They reinforce the need for a coordinated and adaptive work programme to ensure the power system remains secure and resilient while supporting the transition to a more electrified, low-emissions economy.

Additional workstream

- 2.7 A new workstream being included in this updated FSR roadmap is the Future System Operation (FSO) workstream. This was established in 2023 in response to the increasing complexity and decentralisation of New Zealand's power system. As more renewable generation, consumer energy resources, and distribution-connected technologies are integrated into the networks, the power system must be able to accommodate greater variability in generation, increased bi-directional power flows, and more active consumer participation.

- 2.8 The workstream was initiated to ensure system operation arrangements remain fit for purpose as these changes accelerate. In June 2026, the Authority published a [Distribution System Operation \(DSO\) roadmap](#).

3 Status of current activities

Work programme update based on the 10 outcome areas

- 3.1 Since 2022, the Authority has progressed work across the 10 outcome areas set out in the FSR roadmap. This section outlines progress to date, any changes to timeframes, and next steps for each outcome area, where applicable. The updated roadmap, including revised timeframes and the integration of FSO and DSO activities, is provided in Appendix A.
- 3.2 To align with the structure of the original roadmap, updates in this section are presented by outcome rather than in chronological order. FSO and DSO activities are discussed separately.

Tasks 7.1 to 7.5: Accommodating future changes within technical requirements

- 3.3 This outcome area focuses on ensuring the Electricity Industry Participation Code 2010 (Code), supporting technical requirements, and System Operator processes remain fit for purpose as the electricity system evolves. The 2022 roadmap identified a programme of work to review Parts 6, 7, 8, 13, and 14 of the Code, modernise supporting standards, manage emerging DER-related system risks, and update System Operator policies, procedures, and tools to support a more distributed electricity system.
- 3.4 A critical part of the Authority's FSR programme is the [review of the common quality requirements in Part 8 of the Code](#). This review was undertaken to ensure the regulatory framework enables new and emerging technologies, particularly IBRs such as wind generation, solar generation, and BESSs.
- 3.5 The review of common quality requirements in Part 8 of the Code identified seven key issues arising from the increasing penetration of renewable and inverter-based generation. These include increasing frequency and voltage variability, declining system strength, declining coverage of fault ride-through obligations, uncertainty regarding responsibility for managing harmonics, insufficient asset information available to network operators and owners, and Code terminology that no longer adequately reflected emerging technologies.
- 3.6 Since the review commenced, the Authority has made 10 Code amendments (Table 2) to address these issues and support the secure integration of new technologies. This Part 8 work programme is currently ongoing.

Table 2: Code amendments made between 2023 and 2026 as part of the review of common quality requirements in Part 8 of the Code.

Date	Code amendment
May 2025	Treat energy storage systems as only generation under Part 8
May 2025	Amend some of the periodic testing requirements to apply to all types of owners of grid-connected dynamic reactive compensation devices
May 2025	Remove the requirement for an excitation system while maintaining the requirement for a voltage control system
May 2025	Update the requirement for a speed governor to allow for a speed governor and/or a frequency control system
May 2025	Expand the under-frequency provisions to include any industry participant whose actions could cause an under-frequency event
May 2025	Clarify that embedded generators must provide an asset capability statement in the format specified by the System Operator
May 2025	Remove the exclusion for wind-powered generating units from periodic testing requirements
May 2026	Incorporate the Connected Asset Commissioning, Testing and Information Standard Code (CACTIS) by reference into the Code
June 2026	Require generators to support frequency when the frequency goes outside the acceptable range (49.9-50.1 Hz). When the frequency stays inside that range, the generators do not have to do anything because the system is operating normally
June 2026	Require more medium-sized generators (10 megawatts (MW) and above) to help keep voltage levels stable and stay connected during power system faults, by lowering the threshold for these technical requirements to 10 MW

- 3.7 Likewise, we have updated parts 6, 7, 13, and 14 of the Code to better incorporate newer technologies and their functions.

Outcome

- 3.8 The updates to the Code, standards, and operational frameworks will support the integration of new generation technologies and DER participation while strengthening risk management. We ensure that the Code applies impartially to synchronous generation and IBR by setting obligations that ensure competitive neutrality. This means that all types of electricity generation technologies are required to support common quality obligations. This supports our strategic outcome in ensuring a secure, reliable, and efficient operation of the power system and electricity market.

Update to the timeframe

- 3.9 The following “snapshot” of the relevant section of the roadmap is included for reference to help readers understand the specific section of the roadmap we are referring to. Please refer to Appendix A for a larger and more readable version of the roadmap.

Opportunity or challenge	Activity	Year 1 22/23	Year 2 23/24	Year 3 24/25	Year 4 25/26	Year 5 26/27	Year 6 27/28	Year 7 28/29	Year 8 29/30	Year 9 30/31	Year 10 31/32
Accommodating future changes within technical requirements	7.1 Review and update Part 8 of the Code										
	7.2 Review and update Parts 1, 6, 7, 13 and 14 of the Code to ensure they align to Part 8										
	7.3 Identify standards to support technical requirements in the Code										
	7.4 Update the Policy Statement to manage emerging risks										
	7.5 Update the System Operator's policies, procedures, guidelines and tools										

- 3.10 When the original roadmap was published, all activities within this outcome area were expected to be completed between FY22/23 and FY24/25. Following the Part 8 review and subsequent work, the timeframe has been extended. Activities are now expected to continue through to FY31/32 to reflect the ongoing need to update technical requirements as the power system evolves.
- 3.11 Task 7.1 (*Review and update Part 8 of the Code*) was originally scheduled to run from FY22/23 to FY24/25. The initially anticipated work has largely been completed through the Part 8 review and associated Code amendments. However, the Authority has since identified new issues requiring further work, such as the connection of large loads, large hybrid loads, and BESS. As further technical and policy issues emerge, we anticipate further Code amendments may be required. For this reason, the task has been extended to FY28/29.
- 3.12 Task 7.2 (*Review and update Parts 1, 6, 7, 13, and 14 of the Code to ensure they align to Part 8*) has also been extended due to its dependency on the outcomes of the Part 8 review. Originally scheduled to be completed in FY24/25, it is now expected to continue until FY28/29.
- 3.13 Tasks 7.3 (*Identify standards to support technical requirements in the Code*) and 7.4 (*Update the Policy Statement to manage emerging risks*) commenced as planned in FY22/23 and will now continue until FY31/32. The original roadmap anticipated Task 7.3 concluding in FY24/25 and Task 7.4 in FY22/23. However, these activities have become ongoing business-as-usual activities, reflecting the need for continuous review of operational policies, procedures and emerging risks. The System Operator will continue to assess whether further updates to the Policy Statement are required.
- 3.14 Task 7.5 (*Update the System Operator's policies, procedures, guidelines and tools*) commenced as planned in FY23/24. Originally expected to conclude in FY25/26, it has been extended to FY31/32 to ensure supporting standards and guidance can continue to evolve alongside future Code amendments.

Tasks 3.1 to 3.3: Coordination of increased connections

- 3.15 The focus of this outcome area is ensuring Grid Owner and System Operator commissioning, connection planning, and operational study processes and tools remain effective as the number, scale and complexity of new connections increase.
- 3.16 The Authority is supporting the System Operator and Grid Owner to review and update the commissioning process and Default Transmission Agreement (DTA) to ensure they continue to support the efficient integration of new connections.

Outcome

- 3.17 This outcome area supports the timely and efficient integration of new connections. It aims to improve the efficiency and effectiveness of planning and connection studies, while enabling power system operations to better utilise DER capabilities, helping to optimise system performance and reliability.

Update to the timeframe

Opportunity or challenge	Activity	Year 1 22/23	Year 2 23/24	Year 3 24/25	Year 4 25/26	Year 5 26/27	Year 6 27/28	Year 7 28/29	Year 8 29/30	Year 9 30/31	Year 10 31/32
Coordination of increased connections	3.1 Update GO and SO commissioning processes and Default Transmission Agreement										
	3.2 Review the approach to planning connection studies										
	3.3 Review operational study tools										

- 3.18 Task 3.1 has been renamed *Update Grid Owner and System Operator commissioning processes and Default Transmission Agreement*. It has been extended by two years and is now expected to be completed in FY27/28 rather than FY25/26. This extension reflects ongoing work on reactive power and voltage management at the transmission–distribution interface. Depending on the outcome of that work, the Authority may amend the DTA to address issues relating to harmonics and reactive power flow.
- 3.19 Current work includes follow-up actions from the February 2026 industry workshop on reactive power flows and voltage coordination, as well as the System Operator's review of the reactive power compliance point in clause 8.23 of the Code through the Common Quality Technical Group.
- 3.20 Task 3.2 (*Review the approach to planning connection studies*) was deferred by a year and ran from FY24/25 to FY25/26. This reflects a shift towards incorporating connection study improvements into business-as-usual activities. This work includes ongoing improvements to the connection studies process and consideration of emerging risks associated with new technologies and large electricity users, such as data centres.
- 3.21 Task 3.3 (*Review operational study tools*) has been deferred two years and is now expected to run from FY25/26 to FY26/27. This change reflects the dependency on completion of Task 3.2 and the implementation of any associated process and framework changes before operational study tools can be updated.

Tasks 6.1 to 6.3: Operating with low system strength

- 3.22 This outcome area focuses on understanding and managing the impacts of declining system strength as the power system transitions to higher levels of IBR. The activities identified in the original roadmap include defining baseline performance criteria, enhancing Code provisions, and developing market mechanisms to procure and dispatch system strength services where needed.
- 3.23 System strength is the ability of the power system to maintain a stable voltage waveform and recover following disturbances. As the proportion of IBR increases and the contribution from synchronous generation decreases, maintaining adequate system strength becomes more challenging.
- 3.24 In 2025, Transpower, in its System Operator role, completed the first stage of this workstream through its [System Strength Literature Review](#). The report examined international regulatory approaches to system strength management, assessed current New Zealand capabilities, and identified further work required to develop system strength guidelines for the New Zealand Power System.

Outcome

- 3.25 This outcome area will help ensure the power system remains secure and stable as IBRs become more prevalent. The work will also support the development of appropriate performance standards for IBR and provide a framework for maintaining sufficient system strength to enable their reliable operation.

Update to the timeframe

Opportunity or challenge	Activity	Year 1 22/23	Year 2 23/24	Year 3 24/25	Year 4 25/26	Year 5 26/27	Year 6 27/28	Year 7 28/29	Year 8 29/30	Year 9 30/31	Year 10 31/32
Operating with low system strength	6.1 Investigate system strength challenges and opportunities										
	6.2 Amend the Code to support performance criteria										
	6.3 Develop suitable market products and tools										

- 3.26 Work on this outcome area commenced as planned with the System Operator's initial investigation into system strength (Task 6.1, *Investigate system strength challenges and opportunities*). However, the timeframe for subsequent activities has been extended to allow for further investigation, the development of robust engineering tools and consideration of market products before decisions are made on regulatory or operational changes. This work is becoming increasingly complex as the power system changes and a wider range of technologies affects system strength in different ways. The revised timeframes reflect this complexity and the dependencies between the activities.
- 3.27 While regulatory settings are being developed, the System Operator will continue to manage system strength risks through existing operational measures and other interim mitigations. Based on its assessment of current system conditions and the expected pace of change, the Authority considers these arrangements sufficient to maintain system security during the revised timeframes.
- 3.28 Task 6.1 has been extended by two years and is now expected to be completed in FY27/28. The next phase of the workstream includes an issues and options paper and a performance criterion for system strength. The additional time reflects the technical complexity of the issues and the need to develop a robust evidence base before progressing further changes.
- 3.29 Task 6.2 (*Amend the Code to support performance criteria*) has been deferred by two years and is now expected to commence in FY27/28 and be completed in FY28/29. This task will consider whether changes to the regulatory framework are required in light of the findings from Task 6.1. Task 6.2 was deferred due to its dependency on the completion of Task 6.1.
- 3.30 Task 6.3 (*Develop suitable market product and tools*) has been deferred by two years and extended by an additional year. Work is now expected to commence in FY26/27 and be completed in FY31/32. While an engineering tools development workstream is already underway, broader work on operational tools and potential market mechanisms will follow completion of the assessment framework and performance criteria developed through Task 6.1. The revised timeframe reflects the sequencing of these dependencies.

Tasks 1.1 to 1.3: Enabling DER services for efficient power system operations

- 3.31 Under this outcome area, the Authority and System Operator are focused on enhancing the wholesale market arrangements to better integrate DER participants. This includes improving the modelling of DER within operational tools and investigating the potential of DER activities.
- 3.32 Several initiatives under this outcome area have built on the Authority's broader work to support the transition to a low-emissions electricity system, including work to [update key regulatory settings for electricity distribution networks](#).

- 3.33 Since the roadmap was published, the Authority has progressed a range of initiatives to support flexibility and DER integration. These include:
- (a) [issuing guidance to support competitive flexibility markets](#)
 - (b) [simplifying and expanding network connection arrangements for distributed generation and storage](#)
 - (c) [enabling aggregated small-scale resources to participate in the wholesale market through pooled bids](#)
 - (d) [updating the regulatory settings for distributed generation pricing](#)
 - (e) [consulting on improved network visibility to support informed investment decisions and more efficient use of flexibility services and DER.](#)
- 3.34 This outcome area has interdependencies with the FSO workstream. Enabling DER participation allows these resources to play a more active role in supporting system security, reliability, and efficiency as the power system evolves and IBR becomes more prevalent.

Outcome

- 3.35 DER has the potential to make a greater contribution to both electricity supply and power system operation. By facilitating greater DER participation, the Authority and System Operator aim to ensure that dispatch market capability can accommodate all participants, improve the efficiency of system operation, and place downward pressure on electricity costs.

Update to the timeframe

Opportunity or challenge	Activity	Year 1 22/23	Year 2 23/24	Year 3 24/25	Year 4 25/26	Year 5 26/27	Year 6 27/28	Year 7 28/29	Year 8 29/30	Year 9 30/31	Year 10 31/32
Enabling DER services for efficient power system operations	1.1 Enhance the Code and market system dispatch capability to accommodate DER bids and offers										
	1.2 Improve real-time security modelling within operational tools										
	1.3 Investigate new DER services to support efficient operation of the power system										

- 3.36 Timeframes for all activities within this outcome area have been extended to reflect interdependencies with activities in the FSO workstream and the visibility and observability of DER workstream, and to accommodate the evolving nature of these workstreams:
- (a) Task 1.1 (*Enhance the Code and market dispatch capability to accommodate DER bids and offers*) has been extended by three years and is expected to be completed in FY27/28.
 - (b) Task 1.2 (*Improve real-time security modelling within operational tools*) was deferred by one year and will now commence in FY26/27. This task has also been extended by two years and is expected to be completed in FY28/29.
 - (c) Task 1.3 (*Investigate new DER services to support efficient operation of the power system*) commenced earlier than anticipated, beginning in FY24/25 rather than FY25/26. This task has also been extended by two years and is expected to be completed in FY26/27.
- 3.37 The Authority will continue to monitor distributors' alignment with the flexibility market guidance, and we expect to undertake a sector-wide assessment by mid-2027.
- 3.38 As part of Stage 2B of the [Network Connection Project](#), the Authority released a consultation paper on plug-in generation, and Code changes for export limits and connection processes in September 2026. Further consultation is planned on improving small-scale distributed generation processes and processing fees in the first quarter of 2027, and another paper on further improvements to export limits in mid-2027.

- 3.39 The Authority expects to publish decisions on proposals to improve the visibility of network capacity by the end of 2026. Subject to those decisions, we expect any new requirements for distributors to publish network capacity information will take effect in late 2027.

Tasks 2.1 to 2.4: Visibility and observability of DER

- 3.40 This outcome area focuses on improving the visibility and observability of DER so that the Authority and System Operator can better understand their impact on power system operation. As the uptake of DER and controllable demand increases, the Authority and System Operator will update the Code, operational procedures and system tools to ensure DER behaviour is appropriately reflected in system planning and operation.
- 3.41 The Authority has undertaken several initiatives to improve visibility of DER across the power system. These include ongoing monitoring of [installed distributed generation](#) and the development of the [Generation Investment Pipeline Dashboard](#). The Authority also issued a notice under clause 2.16 of the Code requiring distributors to provide additional information on significant distributed generation from December 2026. Load information requirements are being discussed with stakeholders. The information collected will support the System Operator and other stakeholders to develop a more comprehensive view of future electricity supply and demand through the dashboard.
- 3.42 This outcome area has interdependencies with the FSO workstream, as improved visibility of DER provides the data, monitoring capabilities, and operational awareness needed for future system operating arrangements.

Outcome

- 3.43 This work aims to support power system security by improving the visibility, monitoring and understanding of DER across the power system. Better information on DER uptake and behaviour will support more accurate forecasting, system planning, and operational decision making, while ensuring emerging risks can be identified and managed effectively.

Update to the timeframe

Opportunity or challenge	Activity	Year 1 22/23	Year 2 23/24	Year 3 24/25	Year 4 25/26	Year 5 26/27	Year 6 27/28	Year 7 28/29	Year 8 29/30	Year 9 30/31	Year 10 31/32
Visibility and observability of DER	2.1 Establish the impact of DER										
	2.2 Determine the credible event risk of DER										
	2.3 Update the Code to clarify DER obligations and operational requirements										
	2.4 Update procedures and tools to include DER asset information										

- 3.44 Due to the extension of Task 2.1 (*Establish the impact of DER*) and the dependency of Tasks 2.2 (*Determine the credible event risk of DER*), 2.3 (*Update the Code to clarify DER obligations and performance and operational requirements*) and 2.4 (*Update procedures and tools to include DER asset information*) on the completion of Task 2.1, the timeframes for all activities within this outcome area have shifted. The changes to the timeframes reflect the slower-than-expected emergence of the underlying DER-related issues:
- Task 2.1 was deferred by one year and extended by two years. This task commenced in FY25/26 and will run until FY27/28.
 - Task 2.2 was deferred two years and will commence in FY26/27.
 - Task 2.3 was deferred two years and extended by one year. This task will run from FY27/28 to FY28/29.
 - Task 2.4 has been deferred three years and extended by one year. This task will run from FY29/30 to FY30/31.

Tasks 4.1 to 4.2: Balancing renewable generation

- 3.45 This outcome area is focused on improving the reliability and accuracy of intermittent generation offers and demand forecasting, while ensuring the System Operator's procurement, testing, and operational processes remain effective as variable renewable generation becomes a larger share of the electricity system.
- 3.46 The Authority has progressed several initiatives in this area. For example, in 2024 we completed a review of wind and solar forecasting arrangements. Following that review, the Authority introduced a new hybrid forecasting approach, allowing generators to use their own forecasts provided they meet specified performance standards. The new approach has reduced forecasting errors by 4–9% compared with the previous arrangements.⁵

Outcome

- 3.47 This outcome area aims to ensure that dispatch can reliably and accurately accommodate increasing levels of IBRs while maintaining power system security and frequency stability.

Update to the timeframe

Opportunity or challenge	Activity	Year 1 22/23	Year 2 23/24	Year 3 24/25	Year 4 25/26	Year 5 26/27	Year 6 27/28	Year 7 28/29	Year 8 29/30	Year 9 30/31	Year 10 31/32
Balancing renewable generation	4.1 Improve market system and generation/demand forecast										
	4.2 Consider new or revised ancillary services to maintain balancing										

- 3.48 Work in this area commenced as planned. However, the overall timeframe has been extended by one year to accommodate interactions with related frequency-management initiatives, such as the ongoing work on system inertia (Task 5).
- 3.49 Task 4.1 (*Improve market system and generation/demand forecast*) is now expected to be completed in FY26/27 rather than FY25/26, while Task 4.2 (*Consider new or revised ancillary services to maintain balancing*) is now expected to be completed in FY27/28 rather than FY26/27.
- 3.50 The Authority is investigating options for managing variability within the 5-minute dispatch interval. We will be considering this work as part of a wider strategy for frequency management that looks at both normal band control and contingency response.

Tasks 5.1 to 5.4: Managing the reduction of system inertia

- 3.51 Managing declining system inertia is an important outcome area as IBRs are expected to make up an increasingly large share of New Zealand's power system. The Authority and System Operator will support the integration of new reserve products by ensuring market systems, invoicing and payment processes, regulatory requirements, procurement plans, testing methodologies, and operational procedures are updated to accommodate their scheduling, dispatch, and use.
- 3.52 To better understand the implications of this transition, the Authority commissioned Transpower, in its role as System Operator, to undertake a [study](#) in 2025 to determine a minimum system inertia threshold for frequency stability in the New Zealand Power System for both the North and South Islands. The study identified that BESS provides an opportunity for faster frequency response which can stabilise frequency in a low inertia system more effectively than synchronous generation reserves.

⁵ [How accurate wind and solar forecasts and the new forecasting arrangement are crucial | Electricity Authority](#)

3.53 System inertia is also currently being monitored through the [FSR indicators](#).

Outcome

3.54 The tasks in this outcome area will ensure that system frequency is maintained, which contributes to the effective operation of the system.

Update to the timeframe

Opportunity or challenge	Activity	Year 1 22/23	Year 2 23/24	Year 3 24/25	Year 4 25/26	Year 5 26/27	Year 6 27/28	Year 7 28/29	Year 8 29/30	Year 9 30/31	Year 10 31/32
Managing reducing system inertia	5.1 Create a frequency management strategy to manage low inertia										
	5.2 Ensure the Code and market system can accommodate evolving requirements										
	5.3 Incorporate new reserve types into the Procurement Plan and testing methodology										
	5.4 Update operational procedures and tools										

3.55 Work in this outcome area commenced earlier than initially planned. This reflects the potential for system inertia risks to emerge earlier than anticipated. The overall timeframe has also been extended from two years to four years to accommodate the scope of work required.

- (a) Task 5.1 (*Create a frequency management strategy to manage low inertia*): We are developing a frequency management strategy to ensure the System Operator has the appropriate set of tools to manage system frequency at least cost to consumers. The strategy will consider how responsibility for frequency management should be allocated across different technologies and asset types as the generation mix evolves.
- (b) As the proportion of intermittent generation increases and more BESS are commissioned, existing arrangements may place a growing share of the frequency management responsibilities on newer assets. The strategy will consider how frequency management arrangements can continue to support power system security and encourage efficient investment.
- (c) This task commenced two years earlier than anticipated and has been extended by one year. This task will run from FY 26/27 to FY27/28. The earlier start was the result of the System Operator's analysis on system inertia⁶ initiated in response to the increasing amount of IBRs. The extension of this workstream is due to the need to consider system inertia in tandem with other frequency management projects that are being planned.
- (d) The priority of Task 5.2 (*Ensure the Code and market system can accommodate evolving requirements*) has been increased following the System Operator's recent analysis on system inertia. The Authority expects to implement a long-term solution for managing inertia-related risks by FY28/29. The timeframe for Task 5.2 has been extended by two years to allow for a comprehensive assessment of the full range of potential solutions for a low inertia scenario. While longer-term regulatory settings are being developed, the System Operator will continue to manage risks associated with reduced system inertia using existing operational tools and measures. In parallel, work on the proposed frequency management strategy will provide a more comprehensive framework for addressing low-inertia conditions, including the development of arrangements such as multiple frequency keeping. This approach enables immediate risks to be managed while robust and enduring long-term solutions are developed.
- (e) Tasks 5.2, 5.3 (*Incorporate new reserve types into the Procurement Plan and testing methodology*), and 5.4 (*Update operational procedures and tools*) will be progressed simultaneously. These tasks were brought forward three years and extended by two years. These tasks will run from FY26/27 to FY28/29. Tasks 5.3 and 5.4 have been

⁶ [Minimum inertia study](#)

extended to align with the timeframe for Task 5.2 as they represent potential follow-on work.

- 3.56 We have refined several activity descriptions to better reflect the intended work programme.
- (a) Task 5.1 has been renamed *Create a frequency management strategy to manage low inertia*.
 - (b) Task 5.2 has been renamed *Ensure the Code and market system can accommodate evolving requirements*.
- 3.57 Planned work in this outcome area includes developing options to manage low-inertia system conditions, incorporating a formal definition of inertia into the Code, integrating emerging reserve types into procurement and testing frameworks, and enhancing operational procedures and analytical tools.

Tasks 8.1 to 8.3: Leveraging new technology to enhance ancillary services

- 3.58 This outcome area focuses on enabling new technologies to provide existing and emerging ancillary services where technically feasible. The Authority, System Operator, Clearing Manager, and WITS manager will assess the effectiveness of current ancillary services, improve tools for monitoring power system performance, and update the Code, market systems, and Procurement Plan to support participation by new technologies.
- 3.59 One example of the work undertaken in this outcome area is the recently completed consultation on Code amendment proposals for [wholesale market arrangements for BESS](#). The Authority proposed enabling bi-directional offer forms for BESS to simplify participation and allow asset owners to more efficiently utilise the full capabilities of batteries across energy, instantaneous reserve, and frequency-keeping markets.

Outcome

- 3.60 Expanding participation in ancillary services is expected to improve the efficiency of ancillary services, create additional revenue opportunities for asset owners, and encourage investment in new technologies. Greater uptake of new technologies can increase power system efficiency while continuing to maintain security and resilience of supply.

Update to the timeframe

Opportunity or challenge	Activity	Year 1 22/23	Year 2 23/24	Year 3 24/25	Year 4 25/26	Year 5 26/27	Year 6 27/28	Year 7 28/29	Year 8 29/30	Year 9 30/31	Year 10 31/32
Leveraging new technology to enhance ancillary services	8.1 Investigate changes to ancillary services										
	8.2 Ensure tools monitor the performance of the power system										
	8.3 Update the Code, market system and Procurement Plan to enable new technology to provide ancillary services										

- 3.61 There are no changes to the timeframes for this outcome area. However, the Authority expects additional work may be required over time to support the ongoing integration of new technologies into ancillary service markets. This will be particularly important as work progresses in related outcome areas, including reducing system inertia and operating with low system strength.

Task 9: Maintaining cyber security

- 3.62 Cyber security remains an important consideration for power system resilience. While responsibility for cyber security extends beyond the Authority's regulatory role and is shared across a range of agencies and industry participants, we recognise the importance of managing cyber security risks as the power system becomes increasingly digitised and interconnected.

- 3.63 As greater volumes of DER integration, digital technologies, and remote dispatch capability are integrated into the electricity system, cyber security risks have the potential to directly impact power system integrity, operational resilience, and security of supply.
- 3.64 The sector should consider potential alignment with New Zealand's broader critical infrastructure and cyber resilience settings, including:
- (a) [the Department of the Prime Minister and Cabinet and the National Cyber Security Centre's Critical Infrastructure programme](#)
 - (b) [the New Zealand Cyber Security Strategy 2026–2030](#)
 - (c) [the National Cyber Security Centre Minimum Cyber Security Standards](#).
- 3.65 The Minimum Cyber Security Standards are particularly relevant for business-critical and externally facing operational technology and supporting systems. Compromise of these systems could affect grid stability, operational visibility, dispatch capability, or wider power system resilience.
- 3.66 We continue to encourage market participants to consider voluntary self-assessment to New Zealand's Protective Security Requirements and to adhere to governance reporting obligations.

Update to the timeframe

Opportunity or challenge	Activity	Year 1 22/23	Year 2 23/24	Year 3 24/25	Year 4 25/26	Year 5 26/27	Year 6 27/28	Year 7 28/29	Year 8 29/30	Year 9 30/31	Year 10 31/32
Maintaining cyber security	9.0 Continually review and update cyber security measures										

- 3.67 There are no changes to the timeframe for this outcome area.

Task 10: Growing skills and capabilities of the workforce

- 3.68 The latest Electricity Engineers' Association's (EEA) [Re-Energise 26](#) report notes while there is no immediate workforce crisis, there are several challenges that need to be addressed to ensure the industry can meet future workforce requirements. Key challenges include sectoral uncertainty, uncoordinated workforce initiatives, and training pipeline issues.
- 3.69 While the Authority monitors workforce and labour market trends through the FSR indicator dashboard, responsibility for addressing workforce capability challenges largely rests with the sector. Industry participants, education providers, and other stakeholders will need to work together to ensure the sector has the skills it needs to support the future needs of the electricity industry.

Update to the timeframe

Opportunity or challenge	Activity	Year 1 22/23	Year 2 23/24	Year 3 24/25	Year 4 25/26	Year 5 26/27	Year 6 27/28	Year 7 28/29	Year 8 29/30	Year 9 30/31	Year 10 31/32
Growing skills and capabilities of the workforce	10.0 Encourage and train the workforce's next generation										

- 3.70 There are no changes to the timeframe for this outcome area.

4 Additional future security and resilience project

Tasks 11.1 to 11.5: The Future System Operation workstream

- 4.1 The FSO workstream examines whether existing operational arrangements, roles, and responsibilities remain fit for purpose as the power system becomes more decentralised with increasing DER, consumer energy resources⁷, and flexible demand. As the review of future system operation falls within the wider FSR programme, we have included it in this revised roadmap.
- 4.2 The FSO workstream was initiated in 2023 following the Authority's consideration of the potential issues and opportunities associated with operating New Zealand's power system under increasing electrification. Changes in generation technology and electricity consumption patterns are resulting in changes to power flows across New Zealand's distribution and transmission networks. In many parts of the power system, traditional one-way power flows are being replaced by bi-directional power flows.
- 4.3 As briefly discussed in the section above, the FSO workstream has interdependencies with the FSR activities relating to DER participation and network visibility. These workstreams support the development of future distribution system operation capabilities and integration of consumer energy resources and DER into New Zealand's power system.
- 4.4 In 2024, the Authority's paper consulted through its paper, [The future operation of New Zealand's power system](#), on how New Zealand's power system should evolve to support a more electrified economy. In response to stakeholder feedback, the Authority published an [issues and options paper](#) in 2025 for consultation that outlined three potential DSO models.
- 4.5 Although stakeholders generally supported a hybrid DSO model, where coordination responsibilities are shared between Transpower (as System Operator) and electricity distributors, the Authority decided not to endorse any one DSO model at this stage and to publish a cross-agency roadmap to support the work being undertaken by electricity distributors on DSO functions and capabilities.
- 4.6 In June 2026 the Authority published a [DSO roadmap](#)⁸ that identifies a critical path for developing one or more DSOs and one or more flexibility service markets regardless of the final DSO model ultimately adopted.

Next steps

- 4.7 From 2027/28 onwards, the Authority will assess how effectively DSO roles and responsibilities are being implemented under the hybrid DSO model and consider whether there is any evidence that a move to the 'total DSO model' or 'total TSO model' would be a more efficient choice in the long term.

5 Next steps

- 5.1 Although the publication of the updated FSR roadmap does not represent a formal Authority consultation, we welcome feedback from interested parties by 8 December 2026. Feedback can be sent to fsr@ea.govt.nz.
- 5.2 The Authority will continue to monitor system conditions and emerging risks, and an update will be published if the Authority finds that the changes are material.

⁷ Consumer energy resources (behind the meter) are a subset of distributed energy resources (DER).

⁸ Refer to the DSO roadmap for details of tasks 11.1 to 11.5

Appendix A : Updated FSR roadmap

	Opportunity or challenge		Activity	Organisation	Year 1 22/23	Year 2 23/24	Year 3 24/25	Year 4 25/26	Year 5 26/27	Year 6 27/28	Year 7 28/29	Year 8 29/30	Year 9 30/31	Year 10 31/32
	Accommodating future changes within technical requirements	7.1	Review and update Part 8 of the Code	EA, T(SO)										
		7.2	Review and update Parts 1, 6, 7, 13 and 14 of the Code to ensure they align to Part 8											
		7.3	Identify standards to support technical requirements in the Code											
		7.4	Update the Policy Statement to manage emerging risks											
		7.5	Update the System Operator's policies, procedures, guidelines and tools											
	Coordination of increased connections	3.1	Update GO and SO commissioning processes and Default Transmission Agreement	EA, T(SO), T(GO)										
		3.2	Review the approach to planning connection studies											
		3.3	Review operational study tools											
	Operating with low system strength	6.1	Investigate system strength challenges and opportunities	EA, T(SO)										
		6.2	Amend the Code to support performance criteria											
		6.3	Develop suitable market products and tools											
	Enabling DER services for efficient power system operations	1.1	Enhance the Code and market system dispatch capability to accommodate DER bids and offers	EA, T(SO)										
		1.2	Improve real-time security modelling within operational tools											
		1.3	Investigate new DER services to support efficient operation of the power system											
	Visibility and observability of DER	2.1	Establish the impact of DER	EA, T(SO)										
		2.2	Determine the credible event risk of DER											
		2.3	Update the Code to clarify DER obligations and operational requirements											
		2.4	Update procedures and tools to include DER asset information											
	Balancing renewable generation	4.1	Improve market system and generation/demand forecast	EA, T(SO)										
		4.2	Consider new or revised ancillary services to maintain balancing											
	Managing reducing system inertia	5.1	Create a frequency management strategy to manage low inertia	EA, T(SO)										
		5.2	Ensure the Code and market system can accomodate evolving requirements											
		5.3	Incorporate new reserve types into the Procurement Plan and testing methodology											
		5.4	Update operational procedures and tools											
	Leveraging new technology to enhance ancillary services	8.1	Investigate changes to ancillary services	EA, T(SO)										
		8.2	Ensure tools monitor the performance of the power system											
		8.3	Update the Code, market system and Procurement Plan to enable new technology to provide ancillary services											
	Maintaining cyber security	9.0	Continually review and update cyber security measures	New Zealand energy sector										
	Growing skills and capabilities of the workforce	10.0	Encourage and train the workforce's next generation	New Zealand energy sector, educational institutions, professional associations										
	Future System Operations	11.1	Design and delivery of one or more DSOs	EA, T(SO), ENA, EECA, distributors, FSPs, CC										
		11.2	Driving efficiencies	EA, T(SO), ENA, EECA, MBIE, distributors, FSPs, CC, DPMC, EEA										
		11.3	Accelerating flexibility	EA, T(SO) ENA, EECA, distributors, retailers, FSPs, CC, Flex Forum, MBIE										
		11.4	Distribution network connection and pricing	EA, ENA, EECA, EEA, Distributors, retailers, CC										
		11.5	Prioritising consumers	EA, T(SO), ENA, EECA, distributors, FSPs										

Colour key:

- Changing generation portfolio
- Foundational opportunities and challenges
- Rise of Distributed Energy Resources

Organisation key:

- CC = Commerce Commission
- EA = Electricity Authority
- EECA = Energy Efficiency & Conservation Authority
- ENA = Electricity Networks Aotearoa
- FSP = Flexibility Service Providers
- MBIE = Ministry of Business, Innovation & Employment
- T(GO) = Transpower (Grid Owner)
- T(SO) = Transpower (System Operator)