Roadmap to achieve the future security and resilience of the New Zealand power system

Draft roadmap for discussion

Version: 1

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1.0 Context

New Zealand's power system is on the cusp of significant transformation driven by four key factors:

- decarbonisation of the electricity industry – the project of reducing greenhouse gas emissions by increasing renewable generation, and reducing reliance on gas and coal fuelled generation
- decarbonisation of the wider economy – the wider project of reducing the use of fossil fuels by increasing electrification
- changing patterns of distribution – including increasing adoption of distributed energy resource (DER) such as solar photovoltaic (PV), electric vehicles (EVs), batteries and smart appliances
- increased digitisation – including more data and better digital tools

Figure 1 shows the impact of these four factors on the current power system and the changes expected by 2030.

Key trends	Current	2030
Decarbonised: Transition to 100% renewables	• 85% renewable electricity • Mostly synchronous generation • Security of supply managed by market • Thermals to meet peaks and dry years • Small amount of DER	• 100% renewable electricity • More asynchronous and inverter-based generation • Will energy-only market manage security of supply? • New solutions needed for peaks and dry year • Increased reliance on DER
Decarbonised: More electrified economy	• High reliance on electricity in the economy • Electricity not relied on heavily for transport • Few, traditional demand growth sources – new industry, new housing	• Very high reliance on electricity in the economy • Electricity relied on heavily for transport and in industry • Many different demand growth sources – hydrogen, data centres, EVs, process heat
Distributed: More distributed electricity system	• Small amount of DER • Limited performance requirements in the Code but small penetration means this is not yet an issue • Limited use of demand-side and battery technology to manage peaks	• Millions of DER able to manage peaks in real-time (EVs, batteries, smart appliances) • Multi-directional power flows • More consumer participation and more market players • Potential issues caused by inverter-based DER
Digitised: Increasing digitisation and use of digital tech	• Increasing data and data management requirements • Gradual use of automation for control and switching • Increased use of data-driven decision making	• Increased complexity and volume of data • Expectation from operators and customers that controls, and communications will be automated and data-driven • Opportunities to improve consistency and efficiency

Figure 1 – Key trends in energy transformation and anticipated outcomes in 2030

The transformation of the power system will result in:

- decarbonisation of the electricity industry - the displacement and retirement of synchronous generation, e.g. coal and gas fired generation, together with an increase in inverter-based resource (IBR) generation, being wind and solar PV and battery storage solutions
- decarbonisation of the wider economy - an increase in variable and intermittent energy sources, being wind and solar, to meet increasing demand from transport and process heat electrification
- changing patterns of decentralisation - a move from a largely centralised power system, where large-scale generation of electricity occurs at central power plants connected to the grid, to a

more decentralised power system, where more energy sources are located outside the grid, which will challenge the existing industry operating boundaries

- increased digitisation - a switch from passive consumers to active consumers, who can instantly reduce their demand and feed excess generation from DER back into the distribution network to manage their electricity usage.

2.0 Purpose of the Future Security and Resilience Programme

As New Zealand's power system is transformed it's important to understand the implications of the changes to the security and resilience of the system to ensure that as an electricity supply industry we can continue to coordinate and operate the power system, as well as continuing to meet consumer expectations.

The Electricity Authority has engaged Transpower, as System Operator, to develop a shared understanding of the future opportunities and challenges for the ongoing security and resilience of New Zealand's power system, and to outline how they can be addressed in an orderly and timely way. That work will be undertaken within what is being called the Future Security and Resilience programme of work.

The programme is being undertaken in three phases (as shown in Figure 2 below):

- Phase 1: A report which identifies the potential security and resilience opportunities and challenges for the New Zealand power system arising from expected future changes in technologies and use of the system. This is now complete and the report can be viewed here: FSR-Phase-1-draft-report-Nov-2021
- Phase 2: A roadmap that outlines a pathway to understand and address these opportunities and challenges in a timely manner and an approach for monitoring the manifestation of risks. This document is the roadmap.
- Phase 3: Delivery of the programme of work outlined in the roadmap. Ongoing from July 2022.

Figure 2 - Phases of the Future Security and Resilience programme

The Phase 1 report identified 10 specific opportunities and challenges, as follows.

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

Table 1 – Opportunities and challenges as identified in the Phase 1 report

Transpower engaged with industry in late November and early December 2021, seeking to validate this identification and the priorities assigned.

This work is not occurring in a vacuum. There are multiple other future-focused initiatives concurrently underway; for example, those led by the Electricity Authority's Market Development Advisory Group (MDAG), and its Innovation and Participation Advisory Group (IPAG) and the Ministry of Business, Innovation & Employment (MBIE).

As Figure 3 shows, there are many interdependencies between these initiatives. Transpower will consider these, including the potential for 'win-win' outcomes in Phase 3 which will include pan-industry engagement, to ensure that the requirements of different parties in the industry are heard and the optimal solution is designed.

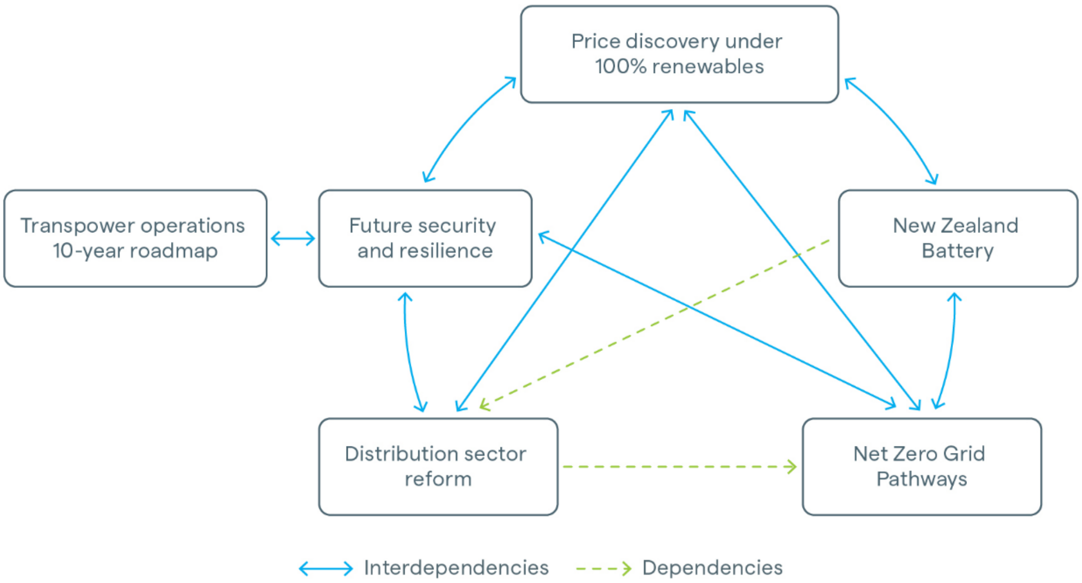

Figure 3 - Known future security and resilience interdependencies and dependencies

Notes on Figure 3

The phrase 'distribution sector reform' refers to a range of initiatives, including the Electricity Authorities consultation on updating regulatory settings for Distribution Networks, the IPAG review of Transpower's Demand Response Programme, Wellington Electricity EV connect discussion paper and Electricity Networks Association Network Transformation Roadmap.

'Price discovery under 100 per cent renewables' refers to an MDAG investigation of how the wholesale electricity market might operate under 100 per cent renewable electricity supply.

The 'New Zealand battery' is a MBIE project investigating solutions to managing dry year security of supply risk.

The 'Net zero grid pathways' is a Transpower project that encompasses the planning and investment required to ensure New Zealand's electricity transmission grid can meet the challenges in enabling electrification of the economy and meeting our decarbonisation targets.

'Transpower operations 10-year roadmap' is a long-term plan outlining the activities required to ensure Transpower meets its operations obligations into the future.

3.0 Intent of the roadmap

The intent of this roadmap is to provide:

- a clear understanding of the activities associated with each opportunity and challenge identified in the report
- a succinct desired outcome for each issue identified in the report
- a schedule of when those activities can be carried out based on the urgency of the issue
- an indication of the primary enabler for the activities required.

The roadmap also highlights interdependencies across the multiple activities, allowing for greater efficiency in delivering outcomes and an indication of the resourcing required.

The System Operator expects that the roadmap will be a living document: as opportunities and challenges emerge faster or slower, or as technology advances change expectations, the Electricity Authority and the System Operator may prioritise or deprioritise activities.

For this reason, a key deliverable before Phase 3 will be to agree a formal change process for the programme which will support timely changes in the scope and timing of roadmap activities.

4.0 Approach for developing the roadmap

The System Operator developed the roadmap based on a bottom-up approach, which considers an extensive range of possible and credible scenarios, to derive final outcomes ensuring the challenges are met and the opportunities realised. The bottom-up approach commenced with brainstorming the needs of system operation, both real-time operation and electricity market operation, and the changes that are required to maintain or improve the security and resilience of the power system in the long-term interests of consumers.

The opportunities and challenges were assessed to determine the:

- reasons for the change
- linkage to Electricity Authority strategic priorities
- parties who will be affected by the change
- deliverable of the change
- benefits of the change
- risks of making and not making the change
- interdependencies between the change and other challenges and opportunities
- ownership: the parties responsible for delivering the change.

All the changes have been consolidated to produce the outcome document and the roadmap.

5.0 Draft roadmap

The following table sets out the Phase 2 draft roadmap. It is based on the Outcome Proposal documents (see Appendix A). Note that the order of challenges and opportunities as listed in the Phase 1 report has been changed to assist with visualising the critical path and "Year" denotes the financial year end (30 June), not the calendar year.

Opportunity or challenge		Activity	Primary enabler	Year 1 2023	Year 2 2024	Year 3 2025	Year 4 2026	Year 5 2027	Year 6 2028	Year 7 2029	Year 8 2030	Year 9 2031	Year 10 2032	Outcome
Accommodating future changes within technical requirements	7.1	Review and update Part 8 of the Code	System Operator, EA											Parts 8, 6, 7, 13, 14 of the Code will be updated to incorporate the capability and performance of new technologies and changes in the power system. Harmonics standards and other engineering standards, modelling and testing standards will take into account the introduction of new technologies. The Policy Statement and any other policies, procedures, guidelines and tools will also be updated accordingly.
	7.2	Review and update Parts 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	Industry											
	7.4	Update the Policy Statement to manage emerging risks	System Operator, EA											
	7.5	Update the System Operator's policies, procedures, guidelines and tools	System Operator											
Coordination of increased connections	3.1	Update Grid Owner and System Operator commissioning processes and benchmark agreement	System Operator, Grid Owner											All System Operator and distributor processes will be updated to accommodate increased connections. The Grid Owner, EDBs and the System Operator will have the resources and capability to commission DER. Updated market tools, real-time operational tools and study tools will reflect the behaviour and capability of DER.
	3.2	Review the approach to planning connection studies												
	3.3	Review and update market and real-time operational tools	System Operator											
Operating with low system strength	6.1	Investigate system strength challenges and opportunities	System Operator											System strength performance criteria will be defined and established. The regulatory framework will be updated to include technical requirements for system strength. Relevant market products, operational procedures and tools will be in place.
	6.2	Amend the Code to require DER to support performance criteria	System Operator, EA											
	6.3	Develop suitable market products and tools	System Operator											
Enabling DER services for efficient power system operations	1.1	Enhance the Code and market system dispatch capability to accommodate DER offers	System Operator											The Code will define the technology agnostic role of DER. The market system will accept offers from DER owners, and operational tools and procedures will assess and dispatch DER. Electricity markets, the Grid Owner, EDBs and the System Operator will send efficient signals to DER. Grid exit point aggregation and participation of third-party flexibility traders will be enabled.
	1.2	Improve real-time security modelling and dispatch tools												
	1.3	Investigate DER functions to support the grid												
Visibility and observability of DER	2.1	Establish the impact of DER	System Operator											The impact of high levels of DER will be understood and managed. The regulatory framework will accommodate a high degree of DER uptake. Operational requirements will be established between the System Operator and distributors/DSOs.
	2.2	Determine the risk DER poses to the system												
	2.3	Update the Code to clarify DER obligations and operational requirements	System Operator, EA											
	2.4	Update procedures and tools to include DER asset information	System Operator											
Balancing renewable generation	4.1	Improve market system and generation/demand forecast	System Operator											The market system, operational procedures and tools will allow the scheduling and dispatching of renewable generation. Intermittent generation offers and the System Operator's demand forecast will be efficient and accurate. New or revised ancillary services will effectively manage active power imbalances.
	4.2	Consider new or revised ancillary services to maintain balancing												
Managing reducing system inertia	5.1	Create a frequency reserve strategy	System Operator											A frequency reserve strategy will be created. The updated Procurement Plan and testing methodologies will support assessment and procurement of new reserve types. Operational procedures and tools will be ready to dispatch new reserve types.
	5.2	Ensure that the Code and the market system can accommodate new reserve types												
	5.3	Incorporate new reserve types in the Procurement Plan and testing methodology												
	5.4	Update operational procedures and tools												
Leveraging new technology to enhance ancillary services	8.1	Investigate ancillary services	System Operator											The regulatory framework, engineering standards and procedures will be updated to reflect the capability and performance of new technologies and other changes within the power system. The Code will enable new technologies to offer ancillary services, and the System Operator's processes and tools will allow new technologies to accept offers and dispatch ancillary services. Studies will identify whether and when new ancillary services products are needed.
	8.2	Ensure tools monitor the performance of the power system												
	8.3	Update market system to enable DER to provide existing ancillary services												
Maintaining cyber security	9.0	Continually review and update cyber security measures	New Zealand energy sector											The energy sector's approach to the management of cyber security will be robust and well coordinated.
Growing skills and capabilities of the workforce	10.0	Encourage and train the workforce's next generation	Industry, educational institutions, professional associations											New Zealand will be able to produce its own workforce, with minimum reliance on overseas talent.

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

6.0 Roadmap interdependencies

Broader interdependencies have been outlined in Figure 3 above, however It is essential to understand how the roadmap deliverables interact with one another, as this will assist in developing a clear critical path for the programme. It may also generate efficiencies where multiple opportunities and challenges can be managed as one.

Most of the opportunities overlap or interact in some way. However, some key interdependencies and dependencies are worth noting.

Accommodating future changes within technical requirements has an interdependency with *Coordination of increased connections* and *Enabling DER services for efficient power system operations.* Creating an inclusive Code will open the door for DER, which also means we must be prepared to cater for increased connections.

Similarly, *Leveraging new technology to enhance ancillary services* is dependent on the work to be done on the Code and other technical standards and support for an increased number of connections, but it has interdependencies with a range of topics, including *Managing reducing system inertia*, *Balancing renewable generation* and *Enabling DER services for efficient power system operations.* This is because as more DER becomes available, ancillary services to support system balancing or to provide synthetic inertia can be evaluated.

Being a localised issue, *Operating with low system strength* is dependent upon how connections are managed, but also will clearly influence the extent to which DER can be leveraged. Decisions need to be made in light of these considerations.

Two challenges do not have interdependencies: *Maintaining cyber security* and *Growing skills and capabilities of the workforce*. The System Operator sees these as foundational challenges; they underpin the entire programme; however, they are not reliant on other activities or tasks.

Figure 4 highlights interdependencies and dependencies between the opportunities and challenges. Appendix A provides more details.

Interdependencies between each opportunity and challenge

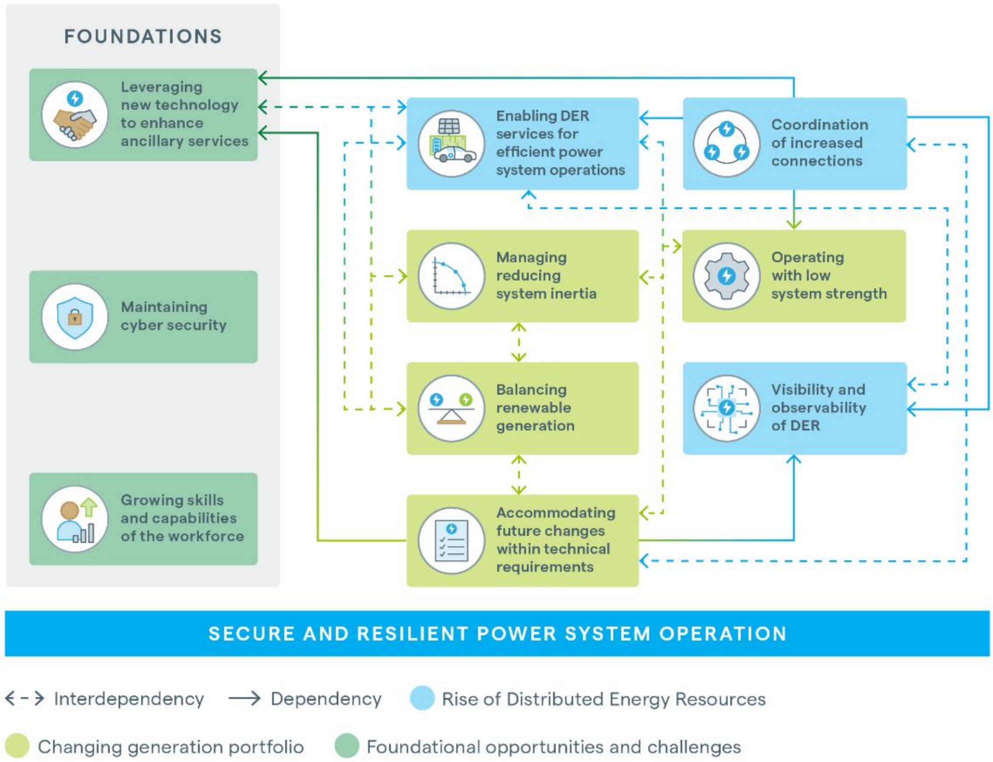

Figure 4 – Interdependencies and dependencies between opportunities and challenges

7.0 Monitoring roadmap priorities

Transpower conducts regular monitoring on its blueprint for a decarbonised economy: see [Whakamana i Te Mauri Hiko Monitoring Reports | Transpower]. This monitoring will assist the System Operator in determining whether the forecast for the future is materialising and the rate of change. Additionally, Table 2 provides specific indicators that will assist in monitoring the prioritisation of each opportunity and challenge. Some challenges, notably *Visibility and observability of DER* and *Operating with low system strength*, require investigations to determine appropriate monitoring measures.

	Rise of Distributed Energy Resources			Changing generation portfolio				Foundational opportunities and challenges		
	Enabling DER services for efficient power system operations	**Visibility and observability of DER**	**Coordination of increased connections**	**Balancing renewable generation**	**Managing reducing system inertia**	**Operating with low system strength**	**Accommodating future changes within technical requirements**	**Leveraging new technology to enhance ancillary services**	**Maintaining cyber security**	**Growing skills and capabilities of the workforce**
Why	Monitoring the amount and type of DER available will assist in identifying opportunities to leverage it for system operations	Establishing a measure for DER impact on system performance will enable the risk to be monitored	Monitoring connection requests will identify emerging risks	Monitoring existing system performance as intermittent generation increases will enable the risk to be monitored	Monitoring existing system performance as the proportion of synchronous generation reduces will enable the risk to be monitored	Establishing a measure for impact of system strength on system performance will enable the risk to be monitored	Ongoing monitoring of system performance and types of connection requests will enable gaps in technical requirements to be identified	Monitoring the number and type of connections, and amount and type of DER will assist in identifying technologies which could be used to enhance ancillary services	Monitoring cyber security events will assist in identifying if this risk is increasing or evolving over time	Monitoring the number and type of skilled resource vacancies to assess if this challenge is increasing or evolving over time
What (Measures)	Number and type of DER installations	TBC pending investigation	Number, location and type of connection requests	Number of frequency and voltage excursions outside acceptable limits	Number of instances where Rate of change of frequency exceeds 0.8 Hz per second for a CE contingency	TBC pending investigation	System performance Number and type of connections requests	Number and type of connection requests Number and type of DER installations	Number and type of cyber security incidents	Number of vacancies for given technical roles
Key	Grid level					Industry wide				

Table 2 – Indicators for monitoring opportunities and challenges

8.0 Summary and next steps

The System Operator has considered the opportunities and challenges outlined in the Phase 1 report in detail and developed a work plan for each. The roadmap collates these work plans and thereby definitively sets out the overall programme of work and the sequencing required however it requires industry engagement to confirm the proposed sequencing. When the roadmap has been finalised, the activities in the roadmap will then be prioritised and funded for delivery over the coming years.

Phase 3 will include a clear change process to expedite necessary changes of scope or priority.

Figure 5 provides a visual summary of the roadmap.

The next steps for the Future Security and Resilience programme are:

- engage with industry to receive feedback on the sequencing of and actions within the roadmap
- confirm the change process and governance model for the Phase 3 programme
- prioritise and fund the Phase 3 programme
- commence the Phase 3 programme
- monitor opportunities and challenges over time and track changes in future trajectory and reprioritising.

Once it is confirmed, the Future Security and Resilience programme will integrate with the Electricity Authority's broader future work programme to support New Zealand to meet its energy goals.

Future Security and Resilience
Outcomes

OPPORTUNITIES AND CHALLENGES

CHANGING GENERATION PORTFOLIO

2022

Accommodating future changes within technical requirements
- Parts 8, 6, 7, 13, 14 of the Code will be updated to incorporate the capability and performance of new technologies and changes in the power system.
- Harmonics standards and other engineering standards, modelling and testing standards will take into account the introduction of new technologies.
- The Policy Statement and any other policies, procedures, guidelines and tools will be updated accordingly.

2025

Operating with low system strength
- System strength performance criteria will be defined and established.
- The regulatory framework will be updated to include technical requirements for system strength.
- Develop suitable market products and tools.

Balancing renewable generation
- The market system, operational procedures and tools will allow the scheduling and dispatching of renewable generation.
- Intermittent generation offers and the System Operator's demand forecast will be efficient and accurate.
- New or revised ancillary services will effectively manage active power imbalances.

2027

Managing reducing system inertia
- A frequency reserve strategy will be created.
- The updated Procurement Plan and testing methodologies will support assessment and procurement of new reserve types.
- Operational procedures and tools will be ready to dispatch new reserve types.

RISE OF DISTRIBUTED ENERGY RESOURCES

Coordination of increased connections
- All System Operator and distributor processes will be updated to accommodate increased connections.
- The Grid Owner, EDBs and the System Operator will have the resources and capability to commission DER.
- Updated market tools, real-time operational tools and study tools will reflect the behaviour and capability of DER.

Enabling DER services for efficient power system operations
- The Code will define the technology agnostic role of DER. The market system will accept offers from DER owners, and operational tools and procedures will assess and dispatch DER.
- Electricity markets, the Grid Owner, EDBs and the System Operator will send efficient signals to DER.
- Grid exit point aggregation and participation of third-party flexibility traders will be enabled.

Visibility and observability of DER
- The impact of high levels of DER will be understood and managed.
- The regulatory framework will accommodate a high degree of DER uptake.
- Operational requirements will be established between the System Operator and distributors/DSOs.

SECURE AND RESILIENT POWER SYSTEM OPERATION

FOUNDATIONS
- Leveraging new technology to enhance ancillary services
- Maintaining cyber security
- Growing skills and capabilities of the workforce

Figure 5 – Summary of the Future Security and Resilience roadmap

Appendix A Outcome proposals

Future Security and Resilience 1: Enabling DER services for efficient power system operations

Problem description

Timeframe	Current capability	Rationale
In 3–7 years	There is limited DER in the power system, and DER is not available for dispatch through the national electricity market.	**Won't be adequate because:** The system needs to be able to leverage new technology to provide the services required for operating the grid at the lowest possible cost.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
The Code, the market system and operational processes enable the use of DER capability to both build and operate the future grid and lower costs for consumers	To enable DER to participate in the electricity market, support system operations, deliver power system operations at lowest cost and assist with 'rightsizing' future electricity networks	Trust and confidence Low-emissions energy Thriving competition	DER owners and flexibility traders Electricity Authority Electricity distribution businesses (EDBs)/Grid Owner Electricity market participants NZX clearing manager NZX wholesale information and trading system (WITS) manager System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: The Code will define the technology agnostic role of DER. The market system will accept offers from DER owners, and operational tools and procedures will assess and dispatch DER. Electricity markets, the Grid Owner, EDBs and the System Operator will send efficient signals to DER. Grid exit point aggregation and participation of third-party flexibility traders will be enabled.	**By** 2029

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
The market will be more efficient, and technologies providing electricity supply will be more diverse, ultimately improving the security and reliability of the power system. The lowering of network peaks will reduce network costs.	**Risk of action:** Without consideration and broad engagement, ineffectiveness in market system and dispatch design for DER	**Risk of inaction:** Untapped resources and reduced observability, along with inefficient investment in generation and networks Difficulty in terms of load forecasting for security and market operation, resulting in the need to carry more capacity reserve/ancillary services, which come at economic cost	FSRs 2, 7 and 8

Governance

Business owner	Delivered by	Priority indicator
Electricity Authority	System Operator	Number of DER installations Observable system performance

Outcome Proposal: FSR 1.1 Enabling DER services for efficient power system operations – Enhance the Code and market system dispatch capability to accommodate DER offers

Problem description

Timeframe	Current capability	Rationale
In 3–7 years	Small-scale and/or aggregated DER is not dispatched through the national market system.	**Won't be adequate because:** DER dispatch is not optimal, leading to inefficiencies.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Enhance wholesale market dispatch capability to accommodate DER	To ensure that current market dispatch capability can accommodate significantly more dispatch participants	See overall Outcome Proposal	DER owners Flexibility traders Market participants Network owners System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: DER will be included in the market design and the Code.	**By** 2027

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
The market will be more efficient, and technologies providing electricity supply will be more diverse, ultimately improving the security and reliability of the power system. The lowering of network peaks will reduce network costs.	**Risk of action:** Without consideration and broad engagement, ineffectiveness in market system and dispatch design for DER	**Risk of inaction:** Untapped resources and reduced observability, along with inefficient investment in generation and networks Difficulty in terms of load forecasting for security and market operation, resulting in the need to carry more capacity reserve/ancillary services, which come at economic cost	N/A

Governance

Business owner	Delivered by	Priority indicator
System Operator	System Operator	See overall Outcome Proposal

Outcome Proposal: FSR 1.2 Enabling DER services for efficient power system operations – Improve real-time security modelling and dispatch tools

Problem description

Timeframe	Current capability	Rationale
In 3–7 years	No security assessment is carried out to assess the operation risk.	**Won't be adequate because:** As uptake of DER increases, the risk of en-masse DER disconnection or unsignalled DER response grows, which may lead to voltage or frequency excursion.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Improve modelling of DER within operational tools and update procedures to consider DER risk	To ensure DER does not negatively affect the security and reliability of the supply	See overall Outcome Proposal	Asset owners Distributors System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: The System Operator will be able to dispatch DER in line with the dispatch of any other asset in the power system.	**By** 2026

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
There will be more options for managing the power system, which in turn will increase the security and reliability of the supply.	**Risk of action:** Without consideration and broad engagement, ineffectiveness in market system and dispatch design for DER	**Risk of inaction:** Failure to fully utilise DER capability, leading to insecure system operation	FSRs 7.1, 7.2, 2.1, 1.3 and 1.1

Governance

Business owner	Delivered by	Priority indicator
System Operator	System Operator	See overall Outcome Proposal

Outcome Proposal: FSR 1.3 Enabling DER services for efficient power system operations - Investigate DER functions to support the grid

Problem description

Timeframe	Current capability	Rationale
In 3–7 years	The operation of the system does not take DER technology into account.	**Won't be adequate because:** DER can provide vital services that will improve the security and reliability of the supply and utilisation of existing assets.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
No change: this is an investigation phase to explore the potential of DER technology	To ensure the system fully utilises DER capability, to ultimately improve its operation	See overall Outcome Proposal	Asset owners Distributors System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: The study will be completed.	**By** 2024

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
The security and reliability of the system operation will improve, system operational cost will reduce and utilisation of existing assets will increase.	**Risk of action:** Without consideration and broad engagement, ineffectiveness in market system and dispatch design for DER	**Risk of inaction:** Failure to fully utilise DER capability, leading to insecure system operation	New technologies, network configuration and FSRs 3.1 and 8

Governance

Business owner	Delivered by	Priority indicator
System Operator	System Operator	See overall Outcome Proposal

Activity	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
FSR 1 – Overall outcome			✓	✓	✓					
FSR 1.1 – Enhance the Code and market system dispatch capability to accommodate DER offers				✓						
FSR 1.2 – Improve real-time security modelling and dispatch tools					✓					
FSR 1.3 – Investigate DER functions to support the grid			✓							

Future Security and Resilience 2: Visibility and observability of DER

Problem description

Timeframe	Current capability	Rationale
In 3–7 years	Because DER operation is currently minimal, visibility and observability of DER is high: demand is easy to predict and forecast.	**Won't be adequate because:** Likely higher uptake of DER and more controllable demand means that the System Operator will require increased visibility of DER to maintain balance within the power system.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Change the Code, operational procedures and tools to improve the visibility and observability of DER	To ensure that the power system operates in a way that considers the behaviour of DER	Trust and confidence Low-emissions energy Thriving competition	Distributors Electricity Authority Grid Owner System Operator

Outcome

Measurable objective	Timeframe

To complete our goal, the future state needs to look like: The impact of high levels of DER will be understood and managed. The regulatory framework will accommodate a high degree of DER uptake. Operational requirements will be established between the System Operator and distributors/distribution system operators (DSOs).	**By** 2027

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
Operation of the system will remain secure.	**Risk of action:** Code or system changes and/or overly onerous costs to enable visibility reduce or impede industry participation, resulting in extra workload for the System Operator and distributors/DSOs	**Risk of inaction:** Insecure system operation Extra workload for the System Operator and distributors/ DSOs	FSRs 1,3 and 7

Governance

Business owner	Delivered by	Priority indicator
Electricity Authority	System Operator	Investigation phase to establish the DER penetration levels which begin to impact the system operation

FSR 2.1: Visibility and observability of DER – Establish the impact of DER

Problem description

Timeframe	Current capability	Rationale
In 3 years	The impacts of DER on the system are not fully understood.	**Won't be adequate because:** Without fully understanding the impacts of DER on the system, the System Operator will not be able to formulate appropriate operational measures

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
No change: this is an investigation phase to establish the potential impacts of DER	To establish operational measures to maintain the system's security	See overall Outcome Proposal	System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: Studies will be completed, and recommendations proposed.	**By** 2024

Benefits

What will this improve and what benefits will be introduced?	Risks?	Interdependencies

The System Operator will understand how DER will impact the secure management of the power system and be able to prepare accordingly	**Risk of action:** Wrong analysis resulting in incorrect decision-making	**Risk of inaction:** Insecure system operation	FSR 1.3

Governance

Business owner	Delivered by	Priority indicator
System Operator	System Operator	See overall Outcome Proposal

FSR 2.2: Visibility and observability of DER – Determine the risk DER poses to the system

Problem description

Timeframe	Current capability	Rationale
In 3–7 years	DER technology is not registered in the Policy Statement as a credible contingency.	**Won't be adequate because:** The potential risk DER entails is not sufficiently understood; this could lead to insecure system operation.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Complete a credible event review (CER) to determine the risk DER poses to the system	To mitigate the risk that may result from disconnection or the unstable operation of DER	See overall Outcome Proposal	Asset owners Distributors System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: A CER will be completed and the Policy Statement updated.	**By** 2024

Benefits

What will this improve and what benefits will be introduced?	Risks?	Interdependencies

Operation of the system will remain secure, and DER capabilities will be fully utilised.	**Risk of action:** Wrong analysis resulting in wrong Credible Contingency risk categorisation	**Risk of inaction:** Failure to consider DER operation, leading to insecure system operation	FSRs 1.3 and 3.

Governance

Business owner	Delivered by	Priority indicator
Electricity Authority	System Operator	See overall Outcome Proposal

FSR 2.3: Visibility and observability of DER – Update the Code to clarify DER obligations and operational requirements

Problem description

Timeframe	Current capability	Rationale
In 3–7 years	The obligations and operation requirements that apply to current grid-connected assets do not currently apply to DER.	**Won't be adequate because:** DER behaviour may increasingly influence the security of the grid and the operation of the system. The System Operator must consider DER behaviour during operation.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Change the Code to clarify the obligations and operation requirements that pertain to DER	To ensure that uptake of DER occurs according to an appropriate regulatory framework	See overall Outcome Proposal	Distributors/DSOs Electricity Authority System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: The regulatory framework will be updated to establish operational requirements between the System Operator and distributors/DSOs.	**By** 2025

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
Improved clarity in terms of operational requirements will allow relevant parties to work together to ensure the secure operation of the system.	**Risk of action:** Resources	**Risk of inaction:** Insecure system operation	FSRs 3.1, 3.2 and 7

Governance

Business owner	Delivered by	Priority indicator
Electricity Authority	System Operator and Electricity Authority	See overall Outcome Proposal

FSR 2.4: Visibility and observability of DER – Update procedures and tools to include DER asset information

Problem description

Timeframe	Current capability	Rationale
In 3–7 years	Security analysis, in real-time dispatch and offline studies, does not consider the influence of DER.	**Won't be adequate because**: DER behaviour may increasingly influence the security of the grid and the operation of the system. The System Operator must address this.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Ensure that DER asset information is available, and update operation procedures and tools	To increase the visibility and observability of DER, to enable improved demand forecasting, outage assessments, security of supply modelling, system security forecasts and annual security assessment, among other procedures and tools, and thereby ultimately enhance the secure operation of the system	See overall Outcome Proposal	Asset owners Distributors/DSOs System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: An operational framework and information and modelling requirements will be established.	**By** 2026

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
Improved visibility of DER will enable the system to operate securely with a high uptake of DER.	**Risk of action:** Increasing visibility will increase DER asset information potentially increasing pressure on resources to effectively incorporate DER into system operation	**Risk of inaction:** Insecure system operation	FSRs 3.1, 3.2 and 7

Governance

Business owner	Delivered by	Priority indicator
Electricity Authority	System Operator, distributors and DSOs	See overall Outcome Proposal

Activity	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
FSR 2 – Overall outcome			✓	✓	✓					
FSR 2.1 – Establish the impact of DER			✓							
FSR 2.2 – Determine the risk DER poses to the system			✓							
FSR 2.3 – Update the Code to clarify DER obligations and operational requirements				✓						
FSR 2.4 – Update procedures and tools to include DER asset information					✓					

Future Security and Resilience 3: Coordination of increased connections

Problem description

Timeframe	Current capability	Rationale
In 0–3 years	New Zealand has a centralised power system characterised by fewer and bigger generating stations, requiring less effort to manage the connection/commissioning process and operation.	**Won't be adequate because:** An exponential increase in connections is likely, due to increasing uptake of DER and smaller generating units. The System Operator will need to put more effort in to commissioning generating stations and maintaining the safe and reliable operation of the system.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Update the Grid Owner's and the System Operator's processes to accommodate a likely increase in connections	To ensure optimal assessments of the impact of connecting DERs and optimal connection processes, thereby ultimately ensuring that the power system operates securely, and market outcomes are efficient	Trust and confidence Low-emissions energy Thriving competition	Asset owners Distributors Electricity Authority Grid Owner System Operator

Outcome

Measurable objective	Timeframe

To complete our goal, the future state needs to look like: All System Operator and distributor processes will be updated to accommodate increased connections. The Grid Owner, EDBs and the System Operator will have the resources and capability to commission DER. Updated market tools, real-time operational tools and study tools will reflect the behaviour and capability of DER.	**By** 2025

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
DER will be able to participate in the power system, providing energy to meet demand and reliability/ancillary services to support secure operation – thereby underpinning New Zealand's energy transition.	**Risk of action:** Inappropriate new connection risk assessments, eroding system security	**Risk of inaction:** Lack of effective integration of DER into system operation, resulting in lost opportunities, ineffective forecasting, insecure operation and delays to the energy transition	FSRs 1, 2 and 7

Governance

Business owner	Delivered by	Priority indicator
Electricity Authority, Grid Owner, System Operator and distributors	TAS, project team and BAU	Number of connections requests Impacts of technologies on system operation Ability to commission high volume of new connections

FSR 3.1: Coordination of increased connections – Update the Grid Owner and System Operator commissioning processes and benchmark agreement

Problem description

Timeframe	Current capability	Rationale
In 0–2 years	The Grid Owner and System Operator commissioning processes and benchmark agreement as well as EDB processes and guidelines are based on the current power system, and have evolved around the requirements of the Code, focusing on generating stations that have obligations to support grid operation.	**Won't be adequate because:** Processes and guidelines need to reflect the inverter technology that DER entails and ensure robust commissioning and testing processes.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Update Grid Owner and System Operator processes and the benchmark agreement	To ensure the timely and efficient integration of DER into the system	See overall Outcome Proposal	Asset owners Distributors Electricity Authority System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: The Grid Owner, EDBs and the System Operator will have adequate commissioning processes and an updated benchmark agreement which incorporates the capability to commission DER.	**By** 2023–2024

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
The effort required of the System Operator and EDBs to commission DER and facilitate the efficient connection of DER to the system will reduce.	**Risk of action:** Inappropriate new connection risk assessments, eroding system security	**Risk of inaction:** Delays in commissioning Lack of clear technical requirements resulting in undesirable DER behaviour An inability to effectively manage multiple station commissioning risks	FSRs 1, 2 and 7

Governance

Business owner	Delivered by	Priority indicator
System Operator	BAU	See overall Outcome Proposal

FSR 3.2: Coordination of increased connections – Review the approach to planning and connection studies

Problem description

Timeframe	Current capability	Rationale
In 1–3 years	The System Operator carries out planning and connection studies for individual generating stations as needed.	**Won't be adequate because:** As the number of individual generating stations increases, the current process for planning and connection studies will become less feasible.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Develop a different approach to planning and running connection studies	To reduce the effort required to carry out planning and connection studies and thereby ensure adequate assessment of the impacts of new connections	See overall Outcome Proposal	Asset owners Grid Owner System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: The System Operator will implement revised planning processes and connection studies to assess new connections.	**By** 2024–2025

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
The effort and cost required of asset owners to complete connection studies will reduce. New assets will operate securely and stably.	**Risk of action:** Inappropriate new connection risk assessments, eroding system security	**Risk of inaction:** Inefficient connection processes and insecure system operation	FSRs 7, 8.1 and 8.2

Governance

Business owner	Delivered by	Priority indicator
System Operator	BAU	See overall Outcome Proposal

FSR 3.3: Coordination of increased connections – Review and update market and real-time operational tools

Problem description

Timeframe	Current capability	Rationale
In 1–3 years	The System Operator tools only model grid-connected stations in detail. They currently model embedded resources and DER as equivalent.	**Won't be adequate because:** There is uncertainty about how to model DER. Equivalent models are good enough for MW dispatch, but inadequate for detailed study related to voltage and system stability.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Review and update market tools, real-time operational tools and study tools used for modelling purposes	To enable power system operations to benefit from the capability of DER	See overall Outcome Proposal	Ancillary service agents Asset owners Distributors Grid Owner System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: The System Operator will update market tools, real-time operational tools and study tools used for modelling purposes to reflect the behaviour and capability of DER.	**By** 2023–2024

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
In realising the benefits of DER capability, the operation of the system and the security of the supply will improve.	**Risk of action:** Inappropriate new connection risk assessments, eroding system security	**Risk of inaction:** Missed opportunity to use DER capability to assist in system operation, New Zealand's energy transition and delivering the lowest-cost future power system Operational issues leading to system-wide disturbance	FSRs 7 and 8.1

Governance

Business owner	Delivered by	Priority indicator
System Operator	BAU	See overall Outcome Proposal

Activity	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
FSR 3 – Overall outcome	✓	✓								
FSR 3.1 – Update the Grid Owner and System Operator commissioning processes and benchmark agreement	✓	✓								
FSR 3.2 – Review the approach to planning connection studies		✓								
FSR 3.3 – Review and update market and real-time operational tools		✓	✓							

Future Security and Resilience 4:
Balancing renewable generation

Problem description

Timeframe	Current capability	Rationale
In 3–7 years	A low proportion of generation is renewable. Conventional generation is highly dispatchable and controllable, ensuring relative certainty in terms of the ability of available generation to meet demand.	**Won't be adequate because:** An increasing proportion of generation will be renewable. Renewable generation relies on natural resources; supply tends to be intermittent and variable, making generation forecasting and maintaining security more challenging.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Make changes to the Code and the System Operator's operational procedures and tools to accommodate an increasing proportion of renewable generation	To ensure that dispatch efficiently accommodates the intermittency and variability of renewable generation and ensure enough generation can be dispatched to meet demand	Trust and confidence Low-emissions energy Thriving competition	Asset owners System Operator

Outcome

Measurable objective	Timeframe

To complete our goal, the future state needs to look like: The market system, operational procedures and tools will allow the scheduling and dispatching of renewable generation. Intermittent generation offers and the System Operator's demand forecast will be efficient and accurate. New or revised ancillary services will effectively manage active power imbalances.	**By** 2027

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
Supply security will improve.	**Risk of action:** The development of operational procedures and tools that are not fit for purpose	**Risk of inaction:** Unreliable supply	FSR 1 and 2

Governance

Business owner	Delivered by	Priority indicator
System Operator	System Operator	Frequency and voltage regulation performance not meeting operational requirements

FSR 4.1: Balancing renewable generation – Improve market system and generation/demand forecast

Problem description

Timeframe	Current capability	Rationale
In 3 years	Generation is offered to the market for at least 36 hours ahead of real time. Intermittent generators must offer for the next 2 hours, based on their current output. The System Operator forecasts conforming demand.	**Won't be adequate because:** As the proportion of intermittent generation offers increases, the likelihood of inaccuracy in the forward supply curve will also increase. Basing offers for the next 2 hours on current output does not take account of variance in generation output that is known (sunrise/sunset) or expected (changes in wind or cloud cover). As the variability in the supply curve increases, the accuracy of the demand forecast becomes increasingly important.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Ensure the obligations the Code places on the formulation of intermittent generation offers are designed to produce the best quality offers, from initial submission through to use in real time Ensure the System Operator's demand forecast is sufficiently accurate	To reduce the proportion of inaccurate offers, inaccurate demand forecasts and any combined inaccuracies, and thereby ultimately ensure the security and reliability of the system	See overall Outcome Proposal	Electricity Authority Intermittent generators Market participants System Operator

Outcome

Measurable objective	Timeframe

To complete our goal, the future state needs to look like: Intermittent generation offers and the System Operator's demand forecast will be efficient and accurate.	**By** 2026

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
Accurate intermittent generation offers, and demand forecasts will enable the market and the System Operator to balance the variance in renewable generation outputs and operate a secure and reliable power system.	**Risk of action:** Increased costs of offering intermittent generation potentially discouraging participation	**Risk of inaction:** Inability to balance the variability of renewable generation in real time, resulting in load shed or inefficient operation and scheduling of the generation fleet	FSR 3

Governance

Business owner	Delivered by	Priority indicator
Electricity Authority (offer accuracy) and System Operator (demand forecast)	Technical advisory service (TAS), project team, business-as-usual (BAU) and Electricity Authority compliance function	See overall Outcome Proposal

FSR 4.2: Balancing renewable generation – Consider new or revised ancillary services to maintain balancing

Problem description

Timeframe	Current capability	Rationale
In 3 years	Frequency keeping ancillary services maintain small active power imbalances.	**Won't be adequate because:** The highly intermittent nature of renewable generation will render the current process less effective.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Ensure that the System Operator's Procurement Plan, testing and operational procedures are appropriate for an increasing proportion of renewable generation	To ensure system frequency is maintained within the normal band	See overall Outcome Proposal	Asset owners System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: New or revised ancillary services will effectively manage active power imbalances.	**By** 2027

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
Improving balancing capability will reduce the impacts of renewable intermittency and allow the System Operator to maintain system frequency within the normal band.	**Risk of action:** Resources	**Risk of inaction:** Insecure system operation	FSRs 1.3 and 2.1

Governance

Business owner	Delivered by	Priority indicator
System Operator	System Operator	See overall Outcome Proposal

Activity	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
FSR 4 – Overall outcome			✓	✓	✓					
FSR 4.1 – Improve market system and generation/demand forecast			✓	✓						
FSR 4.2 – Consider new or revised ancillary services to maintain balancing					✓					

Future Security and Resilience 5: Managing reducing system inertia

Problem description

Timeframe	Current capability	Rationale
In 7–10 years	Following a contingency, the System Operator schedules frequency reserves to manage frequency within the operational limits.	**Won't be adequate because:** IBR generation will increasingly displace synchronous generation, reducing system inertia and making present frequency reserve ineffective in managing the fast rate of change frequency events.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Create a new frequency management strategy	To improve the System Operator's ability to manage frequency following a contingency.	Trust and confidence Low-emissions energy Thriving competition	Ancillary service agents Asset owners System Operator

Outcome

Measurable objective	Timeframe

To complete our goal, the future state needs to look like: A new frequency reserve strategy will be created. The updated Procurement Plan and testing methodologies will support assessment and procurement of new reserve types. Operational procedures and tools will be ready to dispatch new reserve types.	**By** 2029

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
The efficiency of the operation of the market will improve, along with the security of the system.	**Risk of action:** Wrong reserve type	**Risk of inaction:** Insecure system operation	FSRs 1, 2 and 4

Governance

Business owner	Delivered by	Priority indicator
System Operator	System Operator	Rate of change of frequency consistently above 0.8 Hz per second for a generation loss contingency

FSR 5.1: Managing reducing system inertia – Determine the most appropriate frequency reserve type for a low-inertia system

Problem description

Timeframe	Current capability	Rationale
In 7–10 years	Following an under-frequency contingency, the System Operator dispatches fast and sustained instantaneous reserves to manage frequency.	**Won't be adequate because:** The system will increasingly be characterised by low inertia. The System Operator will need to develop a new reserve type to respond to this.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
No change: this is an investigation phase to determine the right reserve type for a low-inertia system	To ensure the effective operation of the system	See overall Outcome Proposal	System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: The study will be completed and inform the development and implementation of a new reserve strategy.	**By** 2029

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
The System Operator will become more effective in managing fast rate of change frequency events.	**Risk of action:** Wrong reserve type	**Risk of inaction:** Insecure system operation	FSRs 1.3, 2.1 and 4.2

Governance

Business owner	Delivered by	Priority indicator
System Operator	System Operator	See overall Outcome Proposal

FSR 5.2: Managing reducing system inertia – Ensure the market system can accommodate new reserve types

Problem description

Timeframe	Current capability	Rationale
In 7–10 years	The functionality of the market system aligns with the current reserve products.	**Won't be adequate because:** The market system needs to accommodate the dispatch, scheduling and optimisation of new reserve products.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Ensure that the market system can offer, schedule and dispatch new reserve products, and that the market system's invoicing and payments processes accommodate these new products Ensure that these changes are reflected in the Code and associated documents	To ensure system frequency is maintained within the normal band	See overall Outcome Proposal	Electricity Authority NZX clearing manager Reserve product providers System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: To be determined following the development of the strategy outlined in 5.1.	**By** 2030

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
(After needs studies have been completed) The security and reliability of the system will improve.	**Risk of action:** Change in the market system for the wrong reserve types or misalignment with needs/operating procedures	**Risk of inaction:** Insecure system operation	FSRs 5, 5.1, 5.3 and 5.4

Governance

Business owner	Delivered by	Priority indicator
System Operator (needs studies, System Operator market system updates), NZX clearing manager (clearing manager's market system updates) and Electricity Authority (Code updates)	System Operator	See overall Outcome Proposal

FSR 5.3: Managing reducing system inertia – Incorporate new reserve types in the Procurement Plan and testing methodology

Problem description

Timeframe	Current capability	Rationale
In 7–10 years	The Procurement Plan specifies technical requirements of current reserve types, and the testing methodology assesses asset capabilities.	**Won't be adequate because:** New reserve types will require new technical requirements and different testing methodologies.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Ensure the System Operator's Procurement Plan and testing methodologies take new reserve types into account	To ensure system frequency is maintained within the normal band	See overall Outcome Proposal	Ancillary service agents Asset owners System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: The updated Procurement Plan and testing methodologies will support the assessment and procurement of new reserve types.	**By** 2030

Benefits

What will this improve and what benefits will be introduced?	Risks?	Interdependencies

Frequency management capability will improve, thereby improving market efficiency and supply security.	**Risk of action:** Procurement and test processes updates are not flexible enough to respond to changing reserve strategy over time	**Risk of inaction:** Insecure system operation	FSR 5.1

Governance

Business owner	Delivered by	Priority indicator
System Operator	System Operator	See overall Outcome Proposal

FSR 5.4: Managing reducing system inertia – Update operational procedures and tools

Problem description

Timeframe	Current capability	Rationale
In 7–10 years	Operational procedures and reserve management tools assess reserve requirements for scheduling and dispatching.	**Won't be adequate because:** New reserve types will require new operational procedures and reserve management tools.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Ensure the System Operator's Procurement Plan and testing and operational procedures take new reserve types into account	To ensure system frequency is maintained within the normal band	See overall Outcome Proposal	Ancillary service agents Asset owners System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: Operational procedures and tools will be ready to dispatch new reserve types.	**By** 2030

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
The System Operator’s ability to manage frequency following an under-frequency event in a lower-inertia system will improve, which will benefit the market and improve the security of the supply.	**Risk of action:** Suboptimal implementation	**Risk of inaction:** Insecure system operation	FSRs 5.1 and 5.2

Governance

Business owner	Delivered by	Priority indicator
System Operator	System Operator	See overall Outcome Proposal

Activity	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
FSR 5 – Overall outcome							✓			
FSR 5.1 – Create a frequency reserve strategy							✓			
FSR 5.2 – Ensure the market system can accommodate new reserve types								✓		
FSR 5.3 – Incorporate new reserve types in the Procurement Plan and testing methodology								✓		
FSR 5.4 – Update operational procedures and tools								✓		

Future Security and Resilience 6: System strength

Problem description

Timeframe	Current capability	Rationale
In 3–7 years	The system is characterised by a high proportion of synchronous generation and a low proportion of IBR generation. Synchronous generation is a positive contributor to the strength of the system.	**Won't be adequate because:** The increasing proportion of IBR generation will lower system strength, potentially causing abnormal performance, instability and generation loss.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Investigate the challenge of low system strength, then define an acceptable performance assessment criterion and update the Code accordingly, to define a baseline for system performance and associated market products Implement supporting operational procedures and tools	To ensure assets remain connected and operate securely and stably during and following voltage disturbances caused by a fault	Trust and confidence Low-emissions energy Thriving competition	Ancillary service agents Asset owners Distributors Electricity Authority Grid Owner System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: System strength performance criteria will be defined and established. The regulatory framework will be updated to include technical requirements for system strength. Relevant market products, operational procedures and tools will be in place.	**By** 2029

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
Ensuring that IBR can ride through system fault will ultimately improve the security and reliability of the system.	**Risk of action:** Unintended consequences such as additional costs incurred to meet system strength performance criteria	**Risk of inaction:** IBR being disconnected or operating unstably following a system fault, which may lead to an under-frequency event or system-wide disturbances	FSRs 1 and 8

Governance

Business owner	Delivered by	Priority indicator
Electricity Authority, Grid Owner, System Operator and distributors	TAS, BAU and project team	Number of localised DER installations Investigation phase to develop a monitoring mechanism for system strength

FSR 6.1: Operating with low system strength – Investigate system strength challenges and opportunities

Problem description

Timeframe	Current capability	Rationale
In 3–4 years	Clause 8.25A of Part 8 of the Code sets out assessment criteria to determine ride-through capability. No other technical requirements specify IBR performance requirements under low-system-strength conditions.	**Won't be adequate because:** Clause 8.25A does not specify the levels of system strength that must be maintained, so new resources may not be able to connect to the system or generate, and any cost of maintaining system strength will not be efficiently allocated.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Undertake an initial assessment to define a baseline for system strength in New Zealand and performance criteria to complement Clause 8.25A of Part 8 of the Code	To ensure performance levels for IBR are appropriate and ultimately maintain the secure and stable operation of the system	See overall Outcome Proposal	Asset owners Distributors Electricity Authority Grid Owner System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: Studies will be completed, and performance criteria will be defined.	**By** 2026

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
Clear criteria will guide asset owners when they are procuring IBR, and the effort required for the System Operator to check compliance will reduce.	**Risk of action:** Wrong analysis resulting in incorrect localised system strength thresholds	**Risk of inaction:** Suboptimal performance of equipment connected to the power system, leading to degradation of system conditions as a whole and a potential negative impact on other connected assets	FSRs 1.3 and 8

Governance

Business owner	Delivered by	Priority indicator
Electricity Authority	TAS	See overall Outcome Proposal

FSR 6.2: Operating with low system strength – Amend the Code to require DER to support performance criteria

Problem description

Timeframe	Current capability	Rationale
In 4 years	The Code does not specify technical requirements for the operation of DER (specifically IBR) in low-system-strength conditions.	**Won't be adequate because:** As the uptake of DER increases, clearly defined technical requirements will facilitate their secure and stable operation.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Amend the Code with additional clauses relevant to DER to support and complement Clause 8.25A	To ensure performance levels for DER are appropriate and ultimately maintain the secure and stable operation of the system	See overall Outcome Proposal	Asset owners Distributors Electricity Authority Grid Owner System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: Part 8 of the Code will be updated to include requirements for system strength.	**By** 2026

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
Clear criteria will guide asset owners when they are procuring IBR, and the effort required for the System Operator to check compliance will reduce.	**Risk of action:** Where Code changes are too conservative, a restricted uptake of technology	**Risk of inaction:** Suboptimal performance of equipment connected to the power system, leading to degradation of system conditions as a whole and a potential negative impact on other connected assets	FSRs 1.3, 6.1 and 6.2

Governance

Business owner	Delivered by	Priority indicator
Electricity Authority	BAU	See overall Outcome Proposal

FSR 6.3: Operating with low system strength – Develop suitable market products and tools

Problem description

Timeframe	Current capability	Rationale
In 3–7 years	There are no products on the market or operational tools to dispatch resources to provide adequate system strength to allow IBR to operate securely and stably.	**Won't be adequate because:** As uptake of IBRs increases, system strength may drop below an acceptable level.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Develop suitable market products to dispatch system strength to meet the shortfall	To ensure system strength does not drop below the level that can cause IBR to operate below the defined performance level	See overall Outcome Proposal	Ancillary service agents Asset owners Distributors Electricity Authority Grid Owner System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: Products and operational tools to dispatch resources to provide additional system strength will be on the market.	**By** 2024–2028

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
The operation of IBR will become more cost-effective and secure.	**Risk of action:** Wrong implementation, leading to suboptimal operation	**Risk of inaction:** Operation of IBR under insecure conditions The cost of interventions to maintain security not being borne by the causer of the problem	FSRs 1.3, 6.1 and 6.2

Governance

Business owner	Delivered by	Priority indicator
System Operator	BAU	See overall Outcome Proposal

Activity	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
FSR 6 – Overall outcome			✓	✓	✓	✓	✓			
FSR 6.1 – Investigate system strength challenges and opportunities			✓	✓						
FSR 6.2 – Amend the Code to require DER to support performance criteria				✓	✓					
FSR 6.3 – Develop suitable market products and tools			✓	✓	✓	✓	✓			

Future Security and Resilience 7: Accommodating future changes within technical requirements

Problem description

Timeframe	Current capability	Rationale
In 0–3 years	The Code, technical standards and operational procedures are based on a centralised generation model and a high proportion of synchronous generation.	**Won't be adequate because:** Increasing uptake of DER and IBR will change the direction of power flow and the behaviour of the system, rendering the Code, standards and procedures not fit-for-purpose.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Review and update the Code and ensure alignment of all other standards, operating procedures, processes and practices	To ensure assets are dispatched and the power system is operating in a secure and efficient manner	Trust and confidence Low-emissions energy Thriving competition	Ancillary service agents Ancillary service providers Asset owners Distributors Electricity Authority Grid Owner System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: Parts 8, 6, 7, 13 and 14 of the Code will be updated to incorporate the capability and performance of new technologies and changes in the power system. Harmonics standards and other engineering standards, modelling and testing standards will take into account the introduction of new technologies. The Policy Statement and any other policies, procedures, guidelines and tools will be updated accordingly.	**By** 2025

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
Use of new-generation technologies will be optimal and efficient, ensuring the system remains secure and maintaining the quality of the supply.	**Risk of action:** Code and technical standard updates that are not inclusive and flexible enough to support evolving technology; a resulting need for ongoing amendments	**Risk of inaction:** Insecure system operation and inefficient market operation, affecting the security, quality and cost of electricity supply Operation being constrained by outdated regulation	FSRs 1, 3 and 8

Governance

Business owner	Delivered by	Priority indicator
Electricity Authority, Grid Owner, System Operator, distributors and Electricity Engineers' Association (EEA)	TAS, project team and BAU	Emerging technologies Connections requests System behaviours

FSR 7.1: Accommodating future changes within technical requirements – Review and update Part 8 of the Code

Problem description

Timeframe	Current capability	Rationale
In 0–2 years	The technical requirements and asset owner performance obligations in set out in Part 8 of the Code only support the operation of the present system, which features high levels of synchronous generation technology.	**Won't be adequate because:** Increasing uptake of new generation technology will require new technical requirements and asset owner performance obligations.

Opportunity statement

What is the change required?	Why is it required?	Which EA strategic priority does this outcome enable?	Who will be impacted?
Review and update Part 8 of the Code	To ensure the technical requirements in Part 8 are aligned to new generation technologies	See overall Outcome Proposal	Ancillary service agents Asset owners Distributors Electricity Authority System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: Part 8 of the Code will be updated.	**By** 2024

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
The power system will continue to be operated securely, reliably and cost-effectively.	**Risk of action:** Resources and incorrect Code change, leading to suboptimal operation	**Risk of inaction:** Failure of the System Operator to comply with its principal performance obligations (PPOs). A reduction in electricity supply security and reliability.	New technology and system requirements

Governance

Business owner	Delivered by	Priority indicator
Electricity Authority	TAS	See overall Outcome Proposal

FSR 7.2: Accommodating future changes within technical requirements – Review and update Parts 6, 7, 13 and 14 of the Code to ensure they align to Part 8

Problem description

Timeframe	Current capability	Rationale
In 1–3 years	The Code is tailored to a power system characterised by a high degree of centralised generation and passive loads.	**Won't be adequate because:** Increasing uptake of DER will change the generation profile of the system. The Code needs to reflect this, to allow maximum use of DER (for example, through participation in the system operation and provision of ancillary services).

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Review Parts 6, 7, 13 and 14 of the Code to ensure they align to Part 8	To ensure the technical performance of DER is aligned to Part 8 of the Code and enable DER to offer ancillary services, thereby ensuring the effective operation of the power system and market system	See overall Outcome Proposal	Ancillary service agents Asset owners Distributors Electricity Authority System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: Parts 6, 7, 13 and 14 of the Code will be updated.	**By** 2024–2025

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
Dependency on centralised generation will reduce, utilisation of transmission and distribution assets will improve and market operation will become more efficient.	**Risk of action:** Resources and incorrect Code change, leading to suboptimal operation	**Risk of inaction:** Limitation of potential benefits from DER, reducing investment return, potentially constraining the system and reducing the security of the supply	New technology and system requirements

Governance

Business owner	Delivered by	Priority indicator
Electricity Authority	TAS and project teams	See overall Outcome Proposal

FSR 7.3: Accommodating future changes within technical requirements – Identify standards to support technical requirements in the Code

Problem description

Timeframe	Current capability	Rationale
In 1–3 years	New Zealand engineering standards (such as AS/NZS 4777.2 Grid connection of energy systems via inverters, Part 2: Inverter requirements) are based on other countries' power systems, and other New Zealand harmonics standards are not New Zealand-specific.	**Won't be adequate because:** New Zealand standards should be aligned to this country's specific operational requirements, to ensure the security of the system.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Identify standards to support the technical requirements in the Code, and work with the EEA and other relevant institutions to adapt or replace the current standards	To ensure appropriate standards are in place and ultimately maintain the security of the system	See overall Outcome Proposal	Academic institutions Ancillary service agents Asset owners Distributors EEA Electricity Authority Grid Owner System Operator

Outcome

Measurable objective	Timeframe

To complete our goal, the future state needs to look like: Harmonics standards and other engineering standards (for example, inverter performance), modelling and testing standards will be updated.	**By** 2023–2032

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
Appropriate standards will guide asset performance, ultimately improving the security and quality of the supply.	**Risk of action:** Resources	**Risk of inaction:** Reduced supply security or quality	New technology and equipment capabilities

Governance

Business owner	Delivered by	Priority indicator
Electricity Authority, System Operator and EEA	Project team	See overall Outcome Proposal

FSR 7.4: Accommodating future changes within technical requirements – Update the Policy Statement to manage emerging risks

Problem description

Timeframe	Current capability	Rationale
In 0–3 years	The Policy Statement defines the risks and detailed procedures to support the System Operator to achieve various PPOs and other deliverables. The Policy Statement is based on the current power system.	**Won't be adequate because:** The Policy Statement needs to reflect and accommodate a power system characterised by a greater proportion of DER and a more complex power flow.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Undertake risk analysis to identify and quantify new risks and derive procedures to manage them	To ensure the System Operator can manage new risks and thereby maintain the security and reliability of the system	See overall Outcome Proposal	Ancillary service agents Asset owners Distributors Grid Owner System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: The Policy Statement will be updated.	**By** 2023

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
Cascade failure and the unnecessary constraint of assets will be avoided.	**Risk of action:** Wrong analysis leading to incorrect risk management	**Risk of inaction:** Impact of unknown risks on the operation of the power system, potentially leading to cascade failure and poor supply quality	FSRs 3.2, 7.1, 7.2 and 7.3

Governance

Business owner	Delivered by	Priority indicator
System Operator	Project team	See overall Outcome Proposal

FSR 7.5: Accommodating future changes within technical requirements – Update the System Operator's policies, procedures, guidelines and tools

Problem description

Timeframe	Current capability	Rationale
In 0–3 years	The System Operator's policies, procedures, guidelines and tools are designed to achieve its PPOs and other deliverables according to the Code, based on the current power system.	**Won't be adequate because:** The System Operator's policies, procedures, guidelines and tools need to reflect and accommodate a power system characterised by a greater proportion of DER and a more complex power flow.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Update the System Operator's policies, procedures, guidelines and tools for the power system and the electricity market	To ensure the secure and efficient operation of the power system and the electricity market	See overall Outcome Proposal	Ancillary service agents Asset owners Distributors Grid Owner System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: Policies, procedures, guidelines and tools will be updated to consider the introduction of new technologies.	**By** 2024–2026

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
Asset capability will improve, along with the security and efficient operation of the system and the electricity market as a whole.	**Risk of action:** Resources, wrong implementation resulting in insecure and inefficient operation	**Risk of inaction:** Insecure system operation and an increase in energy price Reputational risk as System Operator	FSRs 7.1, 7.2, 7.3 and 7.4

Governance

Business owner	Delivered by	Priority indicator
System Operator	Project team and BAU	See overall Outcome Proposal

Activity	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
FSR 7 – Overall outcome	✓	✓	✓							
FSR 7.1 – Review and update Part 8 of the Code	✓	✓								
FSR 7.2 – Review and update Parts 6, 7, 13 and 14 of the Code to ensure they align to Part 8		✓	✓							
FSR 7.3 – Identify standards to support technical requirements in the Code	✓	✓	✓							
FSR 7.4 – Update the Policy Statement to manage emerging risks	✓									
FSR 7.5 – Update the System Operator's policies, procedures, guidelines and tools		✓	✓							

Future Security and Resilience 8: Leveraging new technology to enhance ancillary services

Problem description

Timeframe	Current capability	Rationale
Enduring	Ancillary services were designed to manage the power system to meet Code requirements – both in terms of products needed and the technologies that can deliver those products.	**Won't be adequate because:** New technologies can change the behaviour of the power system. The system may then require new ancillary services to maintain the same level of supply security and reliability. Equally, new technologies may be capable of replacing existing ancillary services.

Opportunity statement

What is the change required?	Why is it required?	Which EA strategic priority does this outcome enable?	Who will be impacted?
Enable new technologies to offer ancillary services Redefine the ancillary services required to meet grid reliability standards to accommodate increasing levels of DER and inverter-based resource (IBR)	To make the best use of the capability of new technologies and, potentially, to maintain the secure operation of the power system	Trust and confidence Low-emissions energy Thriving competition	Asset owners Ancillary service agents Distributors Grid Owner System Operator

Outcome

Measurable objective	Timeframe

To complete our goal, the future state needs to look like: The regulatory framework, engineering standards and procedures will be updated to reflect the capability and performance of new technologies and other changes within the power system. The Code will enable new technologies to offer ancillary services, and the System Operator's processes and tools will allow new technologies to accept offers and dispatch ancillary services. Studies will identify whether and when new ancillary services products are needed.	**By** 2025

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
Market operation will be more efficient, and system operation more secure.	**Risk of action:** Without proper analysis or industry engagement, and ahead of a clear need, unnecessary services and other inefficiencies	**Risk of inaction:** Failure to make full use of the capabilities of new technologies and to manage the credible risk	FSRs 1, 7 and 8

Governance

Business owner	Delivered by	Priority indicator
Electricity Authority	System Operator	Emerging technologies able to offer ancillary services Power system regulation requirements and outcome of gap analysis

FSR 8.1: Leveraging new technology to enhance ancillary services – Investigate ancillary services

Problem description

Timeframe	Current capability	Rationale
In: 3–7 years	Ancillary services are procured under annual contracts. Frequency regulation and contingency reserve are scheduled in real time through market optimisation.	**Won't be adequate because:** The System Operator may need to procure different forms of frequency reserve and voltage regulation reserve and may need to consider different scheduling requirements due to changes in power system behaviour caused by uptake of new technologies.

Opportunity statement

What is the change required?	Why is it required?	Which EA strategic priority does this outcome enable?	Who will be impacted?
No change: this is an investigation phase to determine the type of reserves the power system requires	To ensure the System Operator procures the right type of services to manage the power system	See overall Outcome Proposal	Ancillary service agents Asset owners System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: Studies will be completed, and recommendations proposed.	**By** 2024

Benefits

What will this improve and what benefits will be introduced?	Risks?	Interdependencies

The System Operator will better understand the need for new ancillary services to manage the power system securely.	**Risk of action:** Without proper analysis or industry engagement, and ahead of identified need, unnecessary services and other inefficiencies	**Risk of inaction:** Ineffective system operation	FSR 1.3

Governance

Business owner	Delivered by	Priority indicator
System Operator	System Operator	See overall Outcome Proposal

FSR 8.2: Leveraging new technology to enhance ancillary services – Ensure tools monitor the performance of the power system

Problem description

Timeframe	Current capability	Rationale
In: 3–7 years	The current real-time power system tools can model the performance of the existing ancillary services and their current means of provision.	**Won't be adequate because:** Current real-time power system tools may not be able to accurately model new means of provision of ancillary services (such as batteries), or they may not be able to accurately model new ancillary services.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Ensure the right tools are in place to monitor the performance of the power system, particularly in a post-event state	To ensure the power system continues to operate in a safe and secure manner	See overall Outcome Proposal	System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: The System Operator will be ready to accurately model new technologies for provision of ancillary services and new ancillary services to support the operation of the system. (The timeframe for the ability to model new ancillary services cannot be established until these services are designed: see FSR 2.1.)	**By** 2025

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
The power system will continue to operate securely, even where ancillary services are being provided from new sources. This will enable increased competition in ancillary service markets.	**Risk of action:** Tool update costs exceeding the benefits of enabling DER to provide ancillary services	**Risk of inaction:** Insecure system operation	FSRs 2.1 and 2.3

Governance

Business owner	Delivered by	Priority indicator
System Operator	System Operator	See overall Outcome Proposal

FSR 8.3: Leveraging new technology to enhance ancillary services – Update market system to enable DER to provide existing ancillary services

Problem description

Timeframe	Current capability	Rationale
In: 3–7 years	Market system tools are designed around the current provision of the existing set of ancillary services.	**Won't be adequate because:** As DER uptake increases, the ability for DER to provide ancillary services increases too. Maintaining the status quo locks DER out of a potential revenue stream, limits competition in the ancillary services market and eliminates the opportunity to leverage the technical capability of DER to provide ancillary services.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Update the market system to enable provision of new and existing ancillary services from DER	To enhance and increase competition in the ancillary services market and maintain the security of the power system	See overall Outcome Proposal	Ancillary service agents Asset owners NZX clearing manager NZX WITS manager System Operator

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: The System Operator will be ready to make full use of the capabilities of new technologies to support the operation of the system.	**By** 2026

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
Ancillary services will be procured cost-effectively. DER will be able to compete equitably in ancillary service markets.	**Risk of action:** The cost of updates to the market system exceeding the benefits delivered	**Risk of inaction:** Suboptimal use of DER assets and their capabilities Increased ancillary service costs	FSRs 2.1 and 2.3

Governance

Business owner	Delivered by	Priority indicator
System Operator	System Operator and NZX (clearing manager, WITS manager)	See overall Outcome Proposal

Activity	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
FSR 8 – Overall outcome			✓	✓						
FSR 8.1 – Investigate ancillary services			✓							
FSR 8.2 – Ensure tools monitor the performance of the power system				✓						
FSR 8.3 – Update market system to enable DER to provide existing ancillary services				✓						

Future Security and Resilience 9: Maintaining cyber security

Problem description

Timeframe	Current capability	Rationale
In Enduring	Adequate security measures are in place to protect against potential cyber attacks.	**Won't be adequate because:** As inter-connections within the power system increase, alongside use of smart technologies, the risk of cyber attack also increases. The adequacy of the current measures will decrease accordingly.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Continually review and update cyber security measures	To improve the effectiveness of cyber security measures and ensure they are up to date	Trust and confidence Low-emissions energy Thriving competition	New Zealand energy sector

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: The energy sector's approach to the management of cyber security will be robust and well coordinated.	**By** 2032

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
The resilience of the power system will improve, and system-wide disturbances and power outages will be avoidable.	**Risk of action:** No risk of action – the action is to mitigate a risk	**Risk of inaction:** Vulnerability to external threats	N/A

Governance

Business owner	Delivered by	Priority indicator
New Zealand energy sector	New Zealand energy sector	Number of cyber security threats experienced

Activity	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
FSR 9 – Overall outcome	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

Future Security and Resilience 10: Growing skills and capabilities of the workforce

Problem description

Timeframe	Current capability	Rationale
In Enduring	There is a shortage of power system engineers and other roles within the electricity market and energy sector.	**Won't be adequate because:** As energy sectors around the world transition to accommodate an increasing proportion of renewable resources, the shortage will become more acute.

Opportunity statement

What is the change required?	Why is it required?	Which Electricity Authority strategic priority does this outcome enable?	Who will be impacted?
Encourage and train the workforce's next generation	To mitigate workforce shortages and ensure that the expected transition within the industry takes place in a safe and timely manner	Trust and confidence Low-emissions energy Thriving competition	Educational institutions New Zealand energy sector Professional associations

Outcome

Measurable objective	Timeframe
To complete our goal, the future state needs to look like: New Zealand will be able to produce its own workforce, with minimum reliance on overseas talent.	**By** As soon as possible

Benefits

What will this improve and what benefits will be introduced?	Risks?		Interdependencies
Workforce shortages will decrease, and the industry's ability to transition to 100% renewable generation in a successful and timely manner will increase.	**Risk of action:** No risk of action – the action is to mitigate a risk	**Risk of inaction:** Shortage of workforce with the right skillsets to transition to and operate the future power system	All the opportunities and challenges in the roadmap

Governance

Business owner	Delivered by	Priority indicator
New Zealand energy sector, educational institutions and professional associations	New Zealand energy sector, educational institutions and professional associations	Increase or decrease in the number of skilled resources Emerging technologies

Activity	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
FSR 10 – Overall outcome	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

Appendix B Glossary

Term/abbreviation	Definition
Ancillary service agent	A contracted provider of ancillary services (the System Operator currently procures five: frequency keeping, instantaneous reserve, over-frequency reserve, voltage support and black start)
Asset owner	A participant who owns an asset used for the generation or conveyance of electricity and a person who operates such asset and, in the case of Part 8, includes a consumer with a point of connection to the grid
BAU	Business as usual
The Code	The Electricity Industry Participation Code: a set of rules that govern New Zealand's electricity industry
CER	Credible event review is a process carried out by the System Operator to review credible contingency events and the classifications of the contingencies
Contingency	The uncertainty of an event occurring, and the planning to cover for it; for example, in relation to transmission, the unplanned tripping of a single item of equipment, or, in relation to a fall in frequency, the loss of the largest single block of generation in service, or loss of one HVDC pole
Credible Contingency	Credible contingency events are events that may plausibly occur, and if they do occur, have the potential of a significant impact on supply security and reliability
DER	Distributed energy resources are controllable energy resource located in the distribution network and not connected directly to the grid. Examples include solar PV, battery energy storage systems and EVs
DSO	Distribution system operators are the entities responsible for distributing and managing energy from generation sources to final consumers
Electricity Authority	Electricity industry regulator in New Zealand
EDB	Electricity distribution business
EEA	Electricity Engineers' Association
FSR	Future Security and Resilience
Grid Owner	Referring to Transpower New Zealand as the grid owner
IBR	Inverter-based resources are assets connected to the grid which interface using inverter technology
IPAG	Innovation Participation Advisory Group advises the Electricity Authority on issues relating to new technologies and business models, and consumer participation
MBIE	Ministry of Business, Innovation and Employment
MDAG	Market Design Advisory Group advises the Electricity Authority on the issues relating to the evolution of the electricity market
NZX	New Zealand's national stock exchange
Policy Statement	A statement within the Code that sets out how Transpower will meet its obligations as System Operator
PPO	The System Operator's principal performance obligations (as set out in the Code)

Procurement Plan	A document that sets out the mechanisms the System Operator uses for procuring ancillary services
System Operator	Referring to Transpower New Zealand Limited as the system operator
TAS	The System Operator’s technical advisory service
WITS	NZX’s wholesale information and trading system

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