Potential solutions for peak electricity capacity issues

Decision paper

18 July 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

New Zealand's already highly renewable electricity system is transforming at a rapid scale and pace which matters for consumers of all sizes. The transition to electrification creates opportunities for consumers to participate in a changing electricity market and benefit from new products and services. It also creates challenges for security of electricity supply, especially for periods of peak demand such as cold mornings or evenings, when the wind is not blowing, and the sun is not shining.

To keep the lights on and maximise the benefits for consumers of our future energy market, we need to balance coordinating available resources as efficiently as possible for security of supply, while maximising benefits for consumers.

The Electricity Authority Te Mana Hiko (Authority) has a long-term plan to ensure security of supply in New Zealand's electricity system, so consumers and industry can have confidence it will deliver what they need and have the right information and tools to make good decisions about their energy use, now and into the future. We are looking to make sure the regulatory environment manages the balance between immediate need and a future power system where:

- consumers are provided with choice and are engaged in providing flexible demand and energy resources
- our market settings reward and incentivise flexibility while ensuring that innovation can take place
- participants actively manage their own risks in a way that builds overall system resilience.

We consulted on *Potential solutions for peak electricity capacity issues* in early 2024. Based on submissions and lessons learned from the recent low residual situation on 10 May 2024, we have decided to further develop the following range of solutions, including:

- **accelerating demand response participation** in the market. This may range from trials and regulatory sandboxes to explore specific barriers and opportunities, to mandating participation in the market
- **changing market settings for security of supply** by updating and consulting on Security Standards Assumptions Document (SSAD). The update seeks to ensure that our market settings are fit-for-purpose, reflect consumer expectations for security of supply, promote confidence in the electricity market, and continue to provide robust signals for investment
- **developing an integrated standby ancillary service in the form of a five-minute variability management tool** to provide cover for a sudden reduction from intermittent sources
- **promoting flexibility and competition** in the wholesale and ancillary service markets by undertaking work to enhance battery energy storage systems (BESS) and dispatchable demand (DD) participation and remove barriers to entry. This includes building additional value streams for flexibility
- **enhancing forward price discovery in flexibility markets** by developing standardised flexibility financial products with the support of industry co-design

- **enhancing outage information and coordination** by developing and consulting on potential improvements to the outage coordination process. We will further improve market information by strengthening the rules for thermal fuel contract disclosure and investigating enhancements to maintain accurate price signals when demand management occurs.

Following consultation, we have decided not to progress any of the interim solutions we consulted on:

- **contracts for out-of-market resource**, including contracts for emergency demand response, may be well-intentioned but are unlikely to be effective at providing additional resilience in the short term to manage peak capacity issues, and they would be a significant departure from the current market and carry a number of risks. These risks include chilling investment signals and undermining confidence in the market. They also include the risk of additional and significant costs of these contracts being passed down to consumers
- **residual payments** for participants to commit their resource to market had very little support and there was mixed evidence of their potential effectiveness.

We are encouraged by the many recent examples of emerging demand-side flexibility (DSF) and by the significant amount of investment in new renewable generation and BESS projects. We want to ensure that any short-term actions do not dampen any investment signals or incentives for this emerging investment and innovation. We will continue to monitor and encourage emerging market-driven tariffs and agreements that encourage demand shifting away from peak periods and provide direct savings to consumers.

Although we will not be implementing the interim options mentioned above, we continue to seek new solutions and improvements to support security of supply. The Authority has a significant work programme underway that is wider than just the decisions signalled in this paper. In addition to the initiatives signalled we are also supporting security of supply by:

- **ensuring the security and resilience of the future electricity system** in the coming decades through our Future Security and Resilience (FSR) programme. This work includes reviewing the common quality requirements in Part 8 of the Code to enable evolving technologies while supporting system security and resilience
- **supporting price discovery in a renewables-based electricity system** by implementing or further investigating the recommendations in the Market Development Advisory Group's (MDAG) report
- **enabling flexibility for consumers** so that they can access a mix of renewable generation, storage and technologies to control their energy use, reduce costs and improve our environment
- **improving distribution pricing** so that consumers can realise benefits from avoiding peak periods
- **reviewing instantaneous reserve cost allocation** to increase incentives for intermittent generation providers to invest in flexibility
- **improving visibility and monitoring of generation investment coming to market** to help with long-term monitoring of security of supply and to support investment confidence and information for decision-making

- **improving the accuracy of intermittent generation forecasts** to support resource coordination and accurate price signals.

These measures will promote reliability, competition, and efficiency in the electricity industry for the long-term benefit of consumers by strengthening public and industry confidence, increasing the number of participants in the electricity and futures markets, encouraging investment, innovation and flexibility, and creating new tools to manage risks and supporting accurate pricing and price discovery.

Contents

1. Purpose

1.1. The Electricity Authority Te Mana Hiko (Authority) has decided to further develop a range of solutions to support security of supply during periods of peak electricity demand. The purpose of this decision paper is to inform of our decisions following our consultation on *Potential solutions for peak electricity capacity issues*[1] (the consultation paper) and to inform of our wider programme of work to support security of supply.

1.2. We consulted on a range of solutions to address peak electricity capacity issues, including:

(a) incentives to provide flexibility such as a standardised 'super peak' financial contract product and mandated market making

(b) accelerating flexibility investment in the form of battery energy storage systems (BESS) and dispatchable demand (DD) enhancements

(c) developing a new integrated ancillary service for standby reserves

(d) interim options to manage short term risks.

1.3. We also consulted on:

(a) the market settings for security of supply

(b) incentives for demand response participation

(c) the evaluation criteria for any potential solutions.

1.4. In response to submissions received, and taking into account recent power system events, we have decided to:

(a) further explore a range of levers to accelerate demand response participation in the market

(b) review the market settings for security of supply to ensure they are fit for purpose, promote confidence in the market and provide robust signals for investment

(c) start development of an integrated standby ancillary service in the form of a five-minute variability management tool to provide cover for a sudden reduction from intermittent sources

(d) undertake work to enhance BESS and DD participation to promote flexibility and competition in the wholesale and ancillary service markets

(e) start the high-level design to develop standardised flexibility products to enhance forward price discovery in flexibility markets

(f) enhance outage coordination by clarifying roles and responsibilities for providing asset outage information and assessing the potential impact on security of supply.

[1] Electricity Authority, *Potential solutions for peak electricity capacity issues*. 2024. Potential solutions for peak electricity capacity issues

1.5. We have also decided not to implement the following interim solutions:

(a) contracts for out-of-market resource

(b) out-of-market tender for emergency demand response

(c) provide payments to participants to commit their resources to market.

1.6. This paper:

(a) explains our long-term view of security of supply

(b) explains our decisions on the potential solutions proposed in the consultation paper and how they support our view of security of supply

(c) highlights the wider programme of work that we are undertaking to support security of electricity supply over three time-horizons

(d) explains the next steps we intend to take following the release of this paper.

2. Our long-term view of security of supply

2.1. New Zealand's electricity system is transforming at a rapid scale and pace. This is already creating challenges for security of electricity supply and the challenges are expected to continue to evolve as New Zealand's economy electrifies.

2.2. The country's generation mix is changing, with a greater penetration of variable renewable generation. The proportion of firm or dispatchable generation, such as thermal or hydro-based generation, has reduced over time as thermal assets are retired or repurposed from baseload to peaking generation and the changing generation mix has coincided with an increase in peak demand as the country electrifies its energy needs.

2.3. For consumers, the transition to electrification presents many opportunities. Changes to technology[2] and retail offerings mean consumers will increasingly participate in electricity markets and support security of supply in the form of demand-side flexibility. Consumers across profiles will increasingly be able to choose whether to only offset their own consumption and reduce cost or become generators, selling excess solar or battery capacity to the market. This move to two-way power flow provides challenges to networks and this needs to be addressed in a coordinated way.

2.4. The Authority is focused on enabling a competitive market that provides affordable solutions for consumers while maintaining security of supply. Our decisions need to address immediate needs as well as prepare for a competitive future power system in which:

(a) consumers are provided with choice and are engaged in providing flexible demand and energy resources

(b) participants actively manage their own risks in a way that builds overall system resilience

[2] Such as rooftop solar photovoltaics, battery energy storage systems and electric vehicle charging and discharging at the residential level.

(c) our market settings reward and incentivise flexibility while ensuring that innovation can take place.

The Authority is taking a long-term view of security of supply

2.5. The Authority has a significant work programme in place to support our long-term view of security of supply. This programme falls across three time-horizons:

(a) Horizon 1 (short term): 2024 to 2027

(b) Horizon 2 (medium term): 2027 to 2031

(c) Horizon 3 (longer term): 2031 to 2050.

2.6. Our programme of work seeks to:

(a) have a strong focus on reliability, aligned with the government's focus on keeping the lights on

(b) encourage investment through robust and accurate price signals

(c) build additional value streams for flexibility

(d) manage costs to consumers through competitive wholesale, ancillary service and retail markets.

2.7. These goals are aligned with our statutory objective along with the Market Development Advisory Group's (MDAG) key pillars for a well-functioning electricity market – accurate pricing (price discovery), tools (to manage risks), competition and public confidence.

2.8. It has also been developed in conjunction with the Security and Reliability Council.[3] Lessons from the low residual situation for the morning peak of 10 May 2024 have also helped to inform this work programme.

2.9. Below is a summary of how the Authority views the outlook across these three horizons. More detailed information on our specific work programme is provided in Table 1 at the end of this section.

Security of supply for the short term: 2024 to 2027

2.10. As the level of intermittent generation increases, there is a growing need for other resources to provide the flexibility required to compensate for the short-term variability in output, for example, during cold, cloudy, windless mornings. This management of intermittent generation variability is referred to as 'firming'.

2.11. Within the next three years (2024 to 2027) we believe demand response and BESS will play an important role in helping to manage security of supply.

2.12. There are already examples of emerging demand-side initiatives in the market (see paragraph 3.58 for more detail), and we expect to see trials of demand-side flexibility tools increase commercial interest over this time horizon. We are encouraged by this emerging innovation and will explore the full range of options to accelerate demand side participation in the wholesale market. This includes our decision to enhance DD participation (see paragraph 3.41 for more detail).

[3] Electricity Authority, *Security and Reliability Council.* https://www.ea.govt.nz/about-us/our-people/our-advisory-and-technical-groups/src/

2.13. Over the past 12 months we have seen the commissioning of New Zealand's first grid connected BESS (35MW) at Rotohiko. Meridian Energy is building a 100MW (200MWh) battery near Ruakākā in Northland. This battery is expected to be fully commissioned by December 2024.[4] Meridian is also bringing forward its investment in a new 100MW battery in Manawatū.[5] Genesis Energy has also signalled its interest in building up to 400MW (800MWh) of battery capacity.[6] Contact Energy has recently confirmed it will build a 100MW (200MWh) battery at Glenbrook.[7]

2.14. A recent Transpower report has highlighted the growing investment in both intermittent generation and BESS. Transpower has received connection enquiries for more than 8,000MW in solar projects. 3,000MW of those solar projects include battery storage.[8]

2.15. We have multiple workstreams underway to prepare for the growing investment in BESS. This includes work to improve BESS modelling and participation in the wholesale and ancillary service markets (see the section beginning at paragraph 3.74 for more detail), work to address the technical requirements for BESS in the Code and work to ensure the workability of the Transmission Pricing Methodology (TPM) for emerging technologies such as BESS.

2.16. As this new flexible capacity matures, we expect that existing hydro and thermal assets will continue to firm intermittent generation and provide the bulk of security of supply for capacity. Figures 1 and 2 demonstrate how hydro and thermal assets are currently providing this role.

2.17. Figure 1 shows the generation mix for the weeks beginning 1 April 2024 to 13 May 2024. It demonstrates how thermal and hydro generation increases or decreases depending on the level of wind generation. For the week beginning 1 April 2024, hydro storage was lower than average for the time of year, so thermal generation was higher this week to compensate for low wind and hydro generation. Following significant rainfall the following week and a subsequent increase in hydro storage, hydro generation performed more of a firming role.

[4] Meridian Energy, *Ruakākā Energy Park*. https://www.meridianenergy.co.nz/new-projects/ruakaka-energy-park

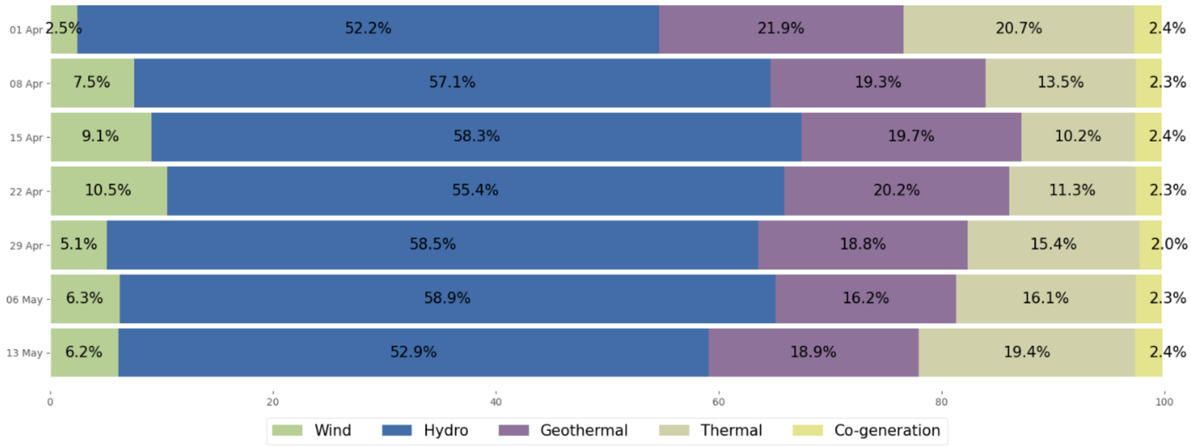
[5] Energy News, *Meridian gearing up for $10 billion generation build*. July 2024, 8. https://www.energynews.co.nz/news/electricity-generation/162637/meridian-gearing-10-billion-generation-build

[6] Genesis Energy, *FY23 Results presentation*. August 2023, 24. https://media.genesisenergy.co.nz/genesis/investor/2023/genesis_fy23_results_presentation.pdf

[7] NZX, *Contact confirms investment in grid-scale battery*. https://www.nzx.com/announcements/433677

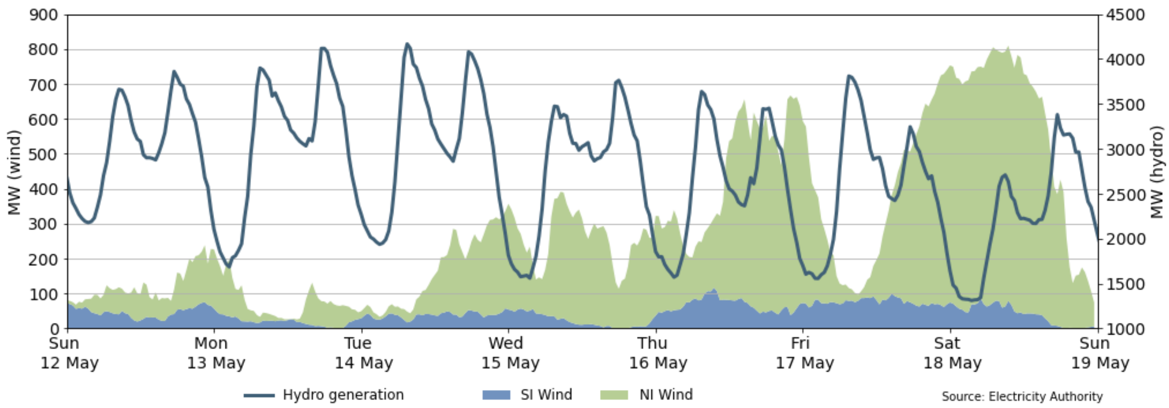
[8] Transpower, *Whakamana i Te Mauri Hiko Monitoring report.* October 2023. Monitoring Report - October 2023 - Final.pdf (transpower.co.nz)

Figure 1: Generation mix for the weeks beginning 1 April 2024 to 13 May 2024



2.18. Figure 2 shows how hydro generation compensates for the changes in wind generation over the space of a week. It shows high hydro generation at the beginning of the week when wind was low, and hydro generation decreasing as wind generation picks up towards the end of the week. Note that wind and hydro generation are displayed on separate axes to make wind generation more visible on the chart.

Figure 2: Hydro and wind generation for 12 to 19 May 2024



2.19. The recent announcement of Genesis Energy's Huntly Firming Options derivative product (HFO)[9] is an example of the market responding to the need for firming by providing options (backed by thermal assets) to mitigate against peak supply risks and shorter duration constraints.

2.20. Our latest generation investment survey (https://www.ea.govt.nz/documents/4414/Generation_Investment_Survey_-_2023_update.pdf) indicates that there is now, based on annual output once built, 5,000 gigawatt hours (GWh) of new generation committed. This is more than double the level of committed generation projects signalled in the 2022 survey. For context, New Zealand currently consumes around 41,000GWh of electricity per year.

2.21. In addition to the committed generation, the survey has identified an additional 20,800GWh of projects that are being actively pursued and could be completed by

[9] Genesis Energy, *Huntly firming options.* May 2024. https://media.genesisenergy.co.nz/genesis/investor/2024/genesis_huntly_firming_options.pdf

2027, which is up from 12,700GWh at the last survey. Of this actively pursued generation around 19,000GWh are from intermittent generation (mostly solar and, to a lesser extent, wind).

2.22. We will continue to monitor this investment pipeline and will publicly report on the speed with which this additional supply comes to market.

2.23. We also have work underway to speed up distribution pricing reform for the benefit of consumers.[10] Distribution pricing reform will play a role in this near-term horizon so that consumers can realise benefits from avoiding peak periods. Efficient distribution pricing will benefit consumers by:

(a) Reducing network upgrades and expansion costs

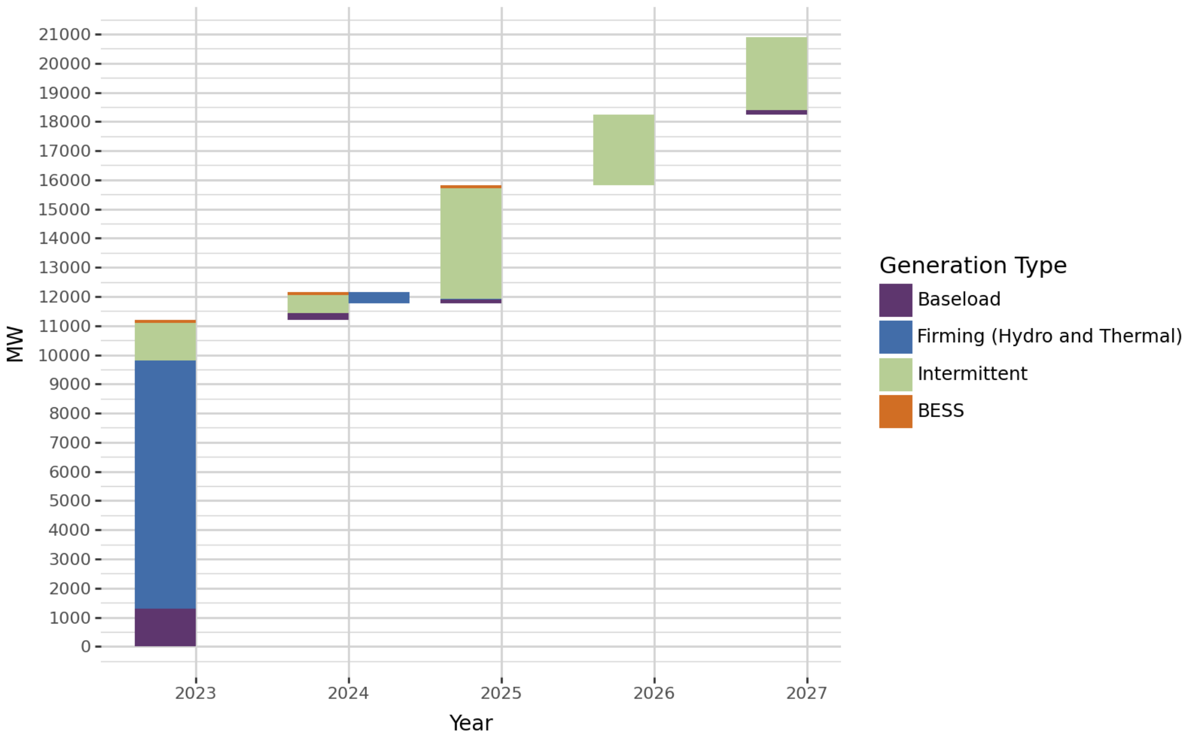
(b) offering more choice and flexibility for consumers, and

(c) enabling consumers to make prudent technology investment decisions.

Intended outcomes for security and resilience:

2.24. Although the emerging investment is positive, we also expect to see the retirement of some thermal assets; most significantly the retirement of Contact Energy's Taranaki Combined Cycle generating unit (360MW) is expected at the end of 2024. Figure 3 demonstrates the expected changes in capacity over the next three years. In this chart, hydro and thermal have been classified as 'firming', and future years include 'committed' and 'actively pursued' projects. This information has been sourced from our investment survey.

Figure 3: Waterfall chart detailing expected changes in capacity until 2027[11]



[10] Electricity Authority, https://www.ea.govt.nz/projects/all/distribution-pricing/

[11] The chart does not include any potential impact from transmission constraints, start-up limitations or fuel limits.

2.25. This chart demonstrates that there is sufficient capacity to meet changes in demand over the next three years. However, the chart also demonstrates the need for more firming given the significant quantity of intermittent generation planned for the next three years. Although Transpower has significant BESS in its connection queue, this investment is not yet signalled as ‘committed’ or ‘actively pursued’ in our investment survey.

2.26. We will continue to model low intermittent generation, high demand scenarios to further test the security of supply outlook for this horizon. Our work to develop a five-minute variability tool will provide an additional tool to provide cover for a sudden reduction from intermittent sources (see the section beginning at paragraph 3.20 for more detail). The ability to forecast and operationally coordinate such scenarios will be supported by our work to improve the accuracy of intermittent generation forecasting.

2.27. Security of supply is likely to still be tight at times over this time horizon, so it will continue to be important for emerging risks to be well communicated and appropriate mitigations are planned and coordinated.

2.28. We have previously highlighted the need for market information and coordination to manage the transition to electrification.[12] In November 2023, we decided to permanently implement three options to better coordinate resources during peak demand periods:

(a) option A: Provide better information on headroom in supply stack

(b) option B: Provide forecast spot rice under demand sensitivity cases

(c) option D: System operator review of wind offers based on external forecast.

2.29. In March 2024, we released a decision to amend the Code to permanently implement option E (Clarify availability and use of ‘discretionary demand’ control).[13]

2.30. Recent power system events further support the need for improved coordination. Our work to enhance outage coordination will provide additional information and coordination to support security of supply. See Appendix B for more information on the low residual situations for 8 May 2024 and 10 May 2024 and our outage coordination work.

2.31. We expect the regulatory environment to enable a system where:

(a) any short-term actions do not dampen any investment signals or incentives for emerging investment and innovation

(b) large consumers have the confidence and tools to support security of supply. This includes appropriate mechanisms and products for participation in the wholesale and ancillary service markets as well as futures markets

(c) the transmission and distribution system accommodates increased renewable generation and the need for flexibility and firming.

[12] Electricity Authority, *Driving efficient solutions to promote consumer interests through winter 2023*. March 2023, 9. https://www.ea.govt.nz/documents/2102/Driving-efficient-solutions-to-promote-consumer-interests-through-winter-2023-_D28umrs.pdf

[13] Electricity Authority, *Code amendment omnibus two decision paper*. March 2024, 28. https://www.ea.govt.nz/documents/4747/Code_amendment_omnibus_two_decision_paper.pdf

Security of supply for the medium term: 2027 to 2031

2.32. Within the following three years (2027 to 2031), we expect to see intermittent generation increasingly built with BESS firming. The previous section noted the increasing BESS firming that Transpower is seeing in its connection queue. Helios and Lightyears solar have also recently announced their intentions to start building batteries alongside their solar farms.[14]

2.33. Enabling flexibility is a key priority for the Authority. We have many initiatives underway to promote the development of flexible resources. As well as the previously mentioned work to enhance DD and BESS participation, some other examples of our work to promote flexibility include:

(a) enhancing forward price discovery in flexibility markets by developing standardised flexibility financial products with the support of industry co-design (see section 3.94 for more detail)

(b) reviewing instantaneous reserve cost allocation to increase incentives for intermittent generation providers to invest in flexibility

(c) developing guidance to support a competitive flexibility services market for more efficient and cost-effective use of the distribution network[15]

2.34. In this time horizon, we expect to see BESS and distributed energy resources (DER) provide increased firming and optionality, although there will still be need for firming from hydro and thermal assets. Our generation investment survey notes that there has been a surge in development of distributed generation, including large utility-scale projects, but also growth in mid-scale and small-scale solar activity.[16] We also note the increase in investment in technologies that support consumers to manage and store energy (consumer energy resources or CER) that generate or store electricity and include flexible loads that can alter demand in response to external signals. We have recently consulted on a proposal to the expand the information in the registry to improve visibility of distributed generation information, include all DER and support a flexibility market by providing more dynamic DER information.[17]

2.35. Data will also be a significant input into the short-to-medium term horizon. Our project to improve retail data monitoring[18] is an example of how we will improve our collecting and monitoring of data to develop insights and inform policy.

Intended outcomes for security and resilience:

2.36. In this time horizon:

(a) Grid and distribution connected assets need to be coordinated to provide security of supply over hours, days, months and years and to ensure efficient

[14] Energy News, *Grid-scale batteries proposed for Otago solar farm.* April 2024, 9. https://www.energynews.co.nz/news/grid-scale-batteries/156606/grid-scale-batteries-proposed-otago-solar-farm

[15] Electricity Authority. https://www.ea.govt.nz/projects/all/distributor-involvement-in-flexibility-services-market/

[16] Concept Consulting, *Generation investment survey.* 2023. https://www.ea.govt.nz/documents/4414/Generation_Investment_Survey_-_2023_update.pdf

[17] Electricity Authority. *Code amendment omnibus three:* May 2024. https://www.ea.govt.nz/documents/4823/Omnibus3_consultation_paper_-_May_2024.pdf

[18] Electricity Authority. https://www.ea.govt.nz/projects/all/improving-retail-market-monitoring/

outcomes. Networks need to increasingly integrate flexibility as consumers become prosumers[19] and can start to exploit the full potential value of their DER and demand response.

(b) Transition risks and opportunities will be managed to reflect regional circumstances. We recognise the needs of consumers will be different depending on their local circumstances. An urban consumer in a major city may need to rely on distribution assets for security of supply as they may not have the space to install on-site resilience.[20] Whereas rural consumers may have the space for localised non-wires alternatives for resilience and may prefer the independence from a distribution network.

(c) As DER and CER investment grows, rural, vulnerable and isolated consumers will become more protected against security of supply risk. We must also consider providing the flexibility for consumer solutions that manage through the vulnerabilities arising from a natural disaster or extreme weather event.

2.37. Our Future Security and Resilience (FSR) work programme and our work on updating distribution regulatory settings is to prepare our system for this future state.

Security of supply for the longer term: 2031 to 2050

2.38. We expect that significant investment in new generation, flexibility and storage options will deliver security of supply.

2.39. We expect that hydro generation will increasingly take on a firming role over longer timeframes – higher average hydro storage levels will provide better energy firming as well as the flexibility providing capacity firming to support BESS and DR.

2.40. Our work on the FSR programme and our work to implement MDAG's recommendations is to prepare our system for the longer term.

Intended outcomes for security and resilience:

2.41. Consumers and communities are empowered to generate and share the value of electricity without compromising security of supply.

2.42. Regulation has kept pace with technology and business practice changes to facilitate a more dynamic market. Consumers are compensated for the flexibility they provide, and the benefits can be shared across communities seamlessly.

2.43. Electricity infrastructure is fit for purpose and can withstand shocks, including cyber, extreme weather and natural disaster resilience.

2.44. The impact of both natural and man-made disruption to supply is lessened and there is resilience across the country. Major infrastructure loss can be compensated for at a local level to ensure that power supply and communication to communities can be sustained while core infrastructure is repaired or replaced.

2.45. The Authority's role is to enable this future market and continue to promote consumer interests. We will plan for specific actions as we move through the short

[19] The term 'prosumers' broadly refers to electricity consumers who can also generation electricity within their premises, 'behind' the electricity meter.

[20] For example, it may be difficult to install BESS or solar generation for an individual apartment.

and medium term. In the meantime, we will monitor security of supply and work with stakeholders to identify trends and incorporate the requirements needed to ensure a competitive and efficient market that is delivering for consumers and the country.

Investment pipeline dashboard

2.46. We have published an investment dashboard that provides visibility of the different types of generation in the pipeline coming to market around the country and across different time horizons.

2.47. The dashboard summarises current generation intentions and the expected new generation from the Authority-commissioned 2022 and 2023 investment surveys. We have also published a list of investment projects which have been publicly announced, with information on each project's status as used in the surveys.

2.48. A copy of the dashboard can be found at https://public.tableau.com/app/profile/electricity.authority/viz/Investmentpipeline/Investmentpipeline.

Table 1: Electricity Authority's work programmes to support security of supply

Project	Purpose	Next milestone	Detail
Improving hedge disclosure obligations	This project will provide the market with more information on risk management contracts to enhance transparency and facilitate ongoing monitoring of evolving markets. Helping participants better manage risk will lead to more efficient prices for consumers – this is increasingly important with greater resilience on intermittent forms of generation in the future. This work will also support price signals which are essential for driving investment in generation and storage.	Decision paper published in June 2024.	Over-the-counter market | Our projects | Electricity Authority (ea.govt.nz)
Review of the common quality requirements in Part 8 of the Code	The review's purpose is to ensure common quality requirements enable evolving technologies, particularly inverter-based resources, to: • facilitate the opportunities offered by evolving technologies • support system security and resilience as more distributed generation is installed and bi-directional electricity flows become more prevalent • ensure that evolving technologies bring about outcomes that are for the long-term benefit of consumers.	Consultation started in June 2024.	This work is part of our wider Future Security and Resilience work programme
Improving the accuracy of intermittent generation forecasts	Incorrect forecasting of intermittent generation can make operational coordination more difficult. Accuracy improvements to existing intermittent generation forecasts will provide better information to flexibility providers (thermal assets, demand response, and batteries) about when	Decision paper published in July 2024.	Improving the accuracy of intermittent generation forecasts | Our projects | Electricity Authority

Project	Purpose	Next milestone	Detail
	they will be needed and will also support more accurate price signals.		
Instantaneous reserve cost allocation	This project will review the principles and Code for allocating the cost of instantaneous reserves, to ensure that these costs are appropriately allocated to intermittent renewable generation. Appropriate cost allocation will increase incentives for intermittent generation providers to invest in flexibility (such as BESS).	Consultation starting in July 2024.	
Accelerating demand response participation	To explore a full range of solutions to accelerate demand response participation in the wholesale market. This may range from trials and regulatory sandboxes (eg, to discover and remove technical and regulatory barriers to entry) to mandating participation in the market for industry participants (eg, by imposing obligations using the Code). The aim of this work is to accelerate demand response participation in the market so that demand response can support security of supply and provide downward pressure on spot prices.	Start work in July 2024.	
Frequency Keeping redesign	Redesign normal frequency management tools to ensure they are fit for purpose in a high inverter-based generation mix. • Stage 1 will improve peak capacity signals and management. It will also increase competition, improve	Start stage 1 work in July 2024.	See the section starting at paragraph 3.20 of this paper

Project	Purpose	Next milestone	Detail
	cost allocation and create an additional value stream for flexible resources. • Stage 2 will enhance normal frequency management.		
BESS enhancements	Increase flexibility by removing barriers to participation in wholesale and ancillary service markets.	Start work in July 2024.	See the section starting at paragraph 3.74 of this paper
Outage coordination	To enhance outage coordination by clarifying roles and responsibilities for providing asset outage information and assessing the potential impact on security of supply. Improvements may include: • making the planned outage coordination process (POCP) mandatory • obligations on asset owners to provide and update outage data during certain time horizons • obligations on asset owners to provide additional information such as recall time for outages • strengthening the system operator’s obligations and actions around outage planning.	Start work in July 2024.	See Appendix B of this paper.
Develop standardised flexibility products	Increase flexibility in the form of financial incentives (hedge products) to enhance forward price discovery in flexibility markets.	Commence high level design in July 2024.	See the section starting at paragraph 3.94 of this paper

Project	Purpose	Next milestone	Detail
Update the Security Standards Assumptions Document (SSAD)	To increase confidence in security of supply assessments by ensuring that the market settings are fit for purpose through the transition and provide the correct incentives for investment.	Start work in July 2024.	See the section starting at paragraph 3.7 of this paper
Reinforce thermal fuel contract disclosure rules	Improve the level of disclosure on thermal fuels available for electricity generation to: • enhance security of supply monitoring • improve performance of the electricity hedge market.	Start work in July 2024.	
Improve visibility of generation investment	Collect and publish data on the pipeline of investments in new generation and load connecting to the transmission network and distribution network. Improving the visibility of this pipeline, as well as connections of large-scale load and battery energy storage systems, will help with monitoring long-term security of supply. The additional information will help support monitoring of competitive outcomes, and constraints to investments, as well as investment confidence and information for decision-making.	Publish consultation paper in mid-2024.	Improving visibility of generation investment | Our projects | Electricity Authority (ea.govt.nz)
DD enhancements	Increase flexibility by lowering technical barriers to participation for commercial and industrial users.	Start work in October 2024.	See the section starting at paragraph 3.41 of this paper

3. Decisions and responses to submissions

3.1. On 12 January 2024, we published a consultation paper *Potential solutions for peak electricity capacity issues*. The consultation period closed on 1 March 2024.

3.2. We received 31 submissions in response to our consultation paper. The consultation paper and submissions can be found on our website at: https://www.ea.govt.nz/projects/all/managing-peak-electricity-demand/consultation/potential-solutions-for-peak-electricity-capacity-issues/

3.3. In response to submissions received, we will:

(a) consult on an update to the market settings for security of supply

(b) start development of an integrated standby ancillary service in the form of a five-minute variability management tool

(c) undertake work to enhance BESS participation

(d) undertake work to enhance DD participation

(e) start the high-level design for standardised flexibility products.

3.4. We have also decided not to implement the following interim solutions:

(a) Contracts for out-of-market resource

(b) Out-of-market tender for emergency demand response

(c) Provide payments to participants to commit their resources to market.

3.5. The following sections provide the detail of our decisions on the issues we consulted on. However, as discussed earlier, we do have a wider programme of work to address security of supply that complement the decisions detailed in this paper.

3.6. Lessons from the low residual situation for the morning peak of 10 May 2024 have also informed our decisions and our wider programme of work. See Appendix B for more information on the events of early May.

The Authority will consult on an update to the market settings for security of supply

3.7. We will consult on an update to the Security Standards Assumptions Document (SSAD) to ensure that security assessments remain fit for purpose.

Summary of the security standards:

3.8. The Authority may publish a SSAD under clause 7.3(2A) of the Code.

3.9. The SSAD sets out the assumptions and standards to be used by the system operator when assessing security of supply (clause 7.3(2B) of the Code).

3.10. The settings in the standards form the basis of the system operator's evaluation of the following security of supply margins:

(a) New Zealand winter energy margin

(b) South Island winter energy margin

(c) North Island winter capacity margin.

3.11. The standards represent an efficient level of reliability – that is, where the expected cost of shortage is equal to the expected cost of new generation. The current standards determine that up to 22 hours per annum of energy or reserve shortfall (as a result of a capacity shortage) is economic before additional investment in peaking generation is warranted. It should be noted that a reserve shortfall can occur without directly impacting consumer supply.

What submitters said:

3.12. Most submitters were concerned about security of supply. Some submitters thought that the Authority should place more emphasis on reliability over other parts of the statutory objective.

3.13. Submitters provided feedback on the factors that they believe the Authority should consider when setting the standards for reliability. This included:

(a) changes to consumer behaviour and the uptake of distributed energy resources

(b) changes to society's tolerance for interruptions of electricity supply. Electricity is an essential service (a necessity) and not a preference

(c) the cost of interruptions to consumers and businesses and the wider costs of supply interruptions such as loss of confidence in the electricity system

(d) the importance of reliability to promote investment and the transition to greater electrification of the economy

(e) the ability to shed controllable load to manage security of supply risks

(f) other considerations relating to generation including profit margins and how to take the unit commitment problem into account.

3.14. In addition to reviewing the standards, Transpower has suggested that information on the size, duration, frequency and timing of potential shortfall events is provided as part of security assessments so that consumers can better understand the quantity and duration of shortfalls.

3.15. Genesis also called for the value of lost load (VoLL) to be updated and Transpower and Nova said that the settings for scarcity prices should be reviewed. Alpine Energy suggested a regular review of the settings.

The Authority's response

3.16. We will consult on an update to the SSAD, taking into account the feedback received, to produce a SSAD that adequately reflects consumers' expectations for security of supply and allows participants to have confidence in the security of supply settings. This review could potentially include a review of VoLL.

3.17. This work will also ensure that the security assessments produced by the system operator remain fit for purpose and provide robust signals for investment.

3.18. MDAG has recommended an update to the scarcity pricing parameters in the Code (recommendation 16). The 10 May event has also highlighted that a review of the scarcity pricing settings, the interaction of reserve scarcity and the use of controllable load ahead of real time may be needed. We will work with the system operator and the industry in any review of market settings and operational practices.

3.19. We aim to have a new SSAD in place before winter 2025 so that the updated standards inform security assessments for winter 2026 and beyond. As part of this update, we will consider the effectiveness of the current five-year review and how often the SSAD should be reviewed.

The Authority will develop an integrated standby ancillary service in the form of a five-minute variability management tool

3.20. We will not implement an integrated standby ancillary service as defined in our consultation paper (see paragraphs 3.22 and 3.23 for more information on what was proposed). Further investigation following the release of the consultation paper has indicated it could be possible to re-purpose the existing Multiple Frequency Keeping (MFK) tool as an integrated five-minute variability management tool.

3.21. A five-minute variability management product is a solution that has emerged through considering feedback on our consultation paper and a review of the Frequency Control Ancillary Service (FCAS) in the Australian National Electricity Market (NEM). We believe that such a tool is aligned with MDAG's recommendation to develop a new reserve product to cover sudden reductions from intermittent sources (recommendation 6).[21]

Summary of integrated standby ancillary service:

3.22. Our consultation paper considered the need to procure standby reserves as an additional ancillary service to support system security management. Standby reserve is the capability to respond to large, unexpected changes in energy requirements. Minimum levels of standby reserve are required for the system operator to maintain system security and reliability. Standby reserve or 'headroom' can be measured in forecast and dispatch schedules as offers of energy available once energy, reserve requirements and frequency keeping requirements have been considered.

3.23. The proposed service would need to be integrated into the spot market and co-optimised with energy and reserves. This means that the same resource could be offered as energy, instantaneous reserves or standby reserves and the system operator's scheduling, pricing and dispatch (SPD) tool would choose the least-cost allocation of the resource as well as provide an efficient price signal for each resource.

What submitters said:

3.24. There was mixed support for an integrated standby ancillary service as defined in the consultation paper.

3.25. Submitters who supported this option were concerned about system reliability and some submitters believe that an integrated standby ancillary service is a prudent option to develop, even if it is only required for the short term.

[21] MDAG, *Price discovery in a renewables-based electricity system: Final Recommendations Paper.* December 2023, 19. https://www.ea.govt.nz/documents/4335/Appendix_A2_-_Final_recommendations_report.pdf

3.26. WEL Networks and Enel X noted that a new ancillary service would provide an additional revenue stream for demand response.

3.27. Submitters who did not support this option believe there are other options to manage the risk such as coordination and monitoring and encouraging flexibility. They were also concerned about costs to consumers and introducing additional complexity to an already complex market.

The Authority's response

3.28. We have considered the feedback and the timeline to implement this solution. The system operator has indicated that this option could take between 3-4 years to implement. We consider that this is too long to address any potential risks and we need a solution that can be implemented in a shorter timeframe.

3.29. Through considering feedback, and a review of previous technical advice, we have identified a solution to address coordination issues to meet peak capacity that will be quicker to implement.

3.30. We have identified that it is possible to repurpose an existing ancillary service to manage variability by redefining the frequency keeping ancillary service, particularly the MFK tool used to select and dispatch frequency keeping providers.

3.31. Work to review the existing frequency keeping service will be split into two stages to ensure that incremental benefits can be delivered earlier rather than waiting until the end of a longer programme of work to realise the full benefits.

3.32. **Stage 1: MFK re-specification and enhancement**

(a) This work involves redefining the existing MFK product into a product to manage five-minute variability and expanding participation in this product to include smaller providers and a wider range of technologies. This would allow the system operator to procure more resource from a wider range of providers to be available to manage variability risk, such as the wind dropping away within a five-minute period.

(b) The system operator currently selects and dispatches generating stations to provide frequency keeping services for each island and for each 30-minute trading period. This service is referred to as MFK. The selected stations can increase or decrease their output in response to a central control signal sent by the system operator every 4 seconds. Such changes are coordinated via the system operator's MFK control, to correct frequency deviations. The system operator currently procures 15MW of MFK in each island.

(c) Frequency keeping providers are currently paid the cost for the offered frequency keeping band plus the constrained on or constrained off cost to the mid-point of the band.[22] Providers also receive the energy market price for their generation.

(d) The system operator undertook some analysis on normal frequency management in 2017.[23] This report indicated that the work of managing

[22] Constrained on or off payments compensate the frequency keeper for any foregone energy market revenue. For example, if a generator increases output to compensate for a decline in system frequency and the energy price was below its energy offer price, it receives a constrained on payment.

[23] See Appendix C.

frequency has shifted from contracted MFK providers to inherent generator governor response[24] and the frequency keeping modulation control (FKC) functionality of the inter-island high voltage direct current (HVDC) link.[25] This is because the speed of response of FKC and generator governors is faster than the speed of the MFK controls.

(e) We have also received an initial study from the system operator to analyse the performance of selected frequency keepers in 2022. This report indicated that the frequency keeper is often in the top 95% of its band limit over winter morning and evening peak periods. This suggests that there could be heightened risk to the system over winter peak periods if the frequency keeper is at the top of its band and wind drops away eg, from the 50th percentile projection to the 10th percentile projection. The frequency keeper would not be able to increase its output as it is already at the top of its band. In its initial report, the system operator stated that it considers there could be a benefit to extend the frequency keeping bands to provide greater ability for the frequency keepers to manage intra-dispatch variations, though more analysis would be required.

(f) The system operator is currently updating the 2017 study. However, we consider it unlikely that the updated findings will indicate that MFK is doing the bulk of the frequency management. Rather, MFK is managing five-minute variability on the system between dispatch instructions. MFK is operating in the timeframe between fast automatic governor response and real time energy dispatch.

(g) Stage 1 of the FK redesign proposes for system frequency to be maintained by FKC and governor response. The existing MFK tool would be repurposed as a five-minute variability tool, similar to Australia's five-minute FCAS. The system operator would retain the ability to vary the band size of the service procured to meet system conditions. However, based on the information provided in previous studies, we anticipate that the system operator is likely to procure additional resource to be available to manage variability risk.[26] Likely volume of additional resource is subject to further analysis by the system operator.

(h) The tool would also be enhanced to increase competition. Enhancements could include removing constrained on and constrained off payments to the five-minute variability provider(s). The system operator currently requires that frequency keeping offer bands are no smaller than 4MW. This is due to the complexity (and solve time) of calculating the total cost of frequency keeping services, in particular the expected constrained on or off costs, when selecting multiple frequency keeping providers. Frequency keeping selection is

[24] A generator's governor regulates the amount of primary energy supply to a turbine (eg, hydro, gas, or steam) inn response to variations in the power system's frequency. This adjusts the generator's output, with the amount and rate of adjustment determined by the size of frequency variation and the governor's characteristics and settings. Thus, a governor will typically respond to a fall in system frequency by automatically increasing generator output and vice versa. This action helps to stabilise (and potentially restore) system frequency movements away from 50Hz. Energy storage systems and demand response can provide similar functionality.

[25] FKC varies the active power on the HVDC link to tie together the North Island and South Island frequencies.

[26] More than the existing 15MW of MFK currently procured in each island.

currently performed in a separate frequency keeping selection tool, it is not performed by the scheduling, pricing and dispatch (SPD) tool.

(i) If constrained on and off payments were removed, these costs would need to be factored into the total offer price for the service for the half hour trading period. By simplifying the payment to just the offer price, it would allow for the 4MW minimum band size to be removed and potentially for selection of the service to be optimised by SPD along with energy and reserves. The move to offers including an allowance for constrained on-off payments would make the full cost of providing the MFK service transparent in the spot market, rather than having part of the cost settled out of market at the end of the month. This, along with larger MFK purchase requirements, would enhance incentives to participate for BESS and other generation.

(j) The proposed changes are intended to increase competition in the five-minute variability market by allowing smaller providers to participate. At this stage we would also investigate participation by other technologies such as BESS and demand-side products. This would further increase competition and build additional value streams for flexibility. We would also look at the appropriate cost allocation for such a service to ensure that costs are allocated to the causers of variability on the system.

(k) We aim to complete the policy development for stage 1 by the end of September 2025.

3.33. **Stage 2: Frequency keeping market revision**

(a) This longer-term piece of work is to assess and redesign normal frequency management tools to ensure they are fit for purpose in a high inverter-based generation mix. This work will be coordinated with the work being done by the Authority on Future Security and Resilience.

(b) The intended outcome of this work is enhanced normal frequency management. We aim to complete the policy development for this work by the end of 2026.

The Authority's assessment of a five-minute variability tool

3.34. We believe that the FK redesign programme has the following advantages:

(a) It will be faster and cheaper to implement than the initial standby ancillary service proposal, as it will repurpose existing market system functionality rather than build brand new functionality

(b) The solution is less complex from a technical and operational perspective. Market participants and the system operator already have experience with using the product.

(c) The solution could provide incentives for additional capacity to be committed to the market, depending on the size of the band determined by the system operator. For 10 May 2024, the difference between the 50th percentile and the 10th percentile wind forecast was around 75MW over the morning peak. Procuring an additional 75MW of capacity to manage variability would have highlighted the low residual situation earlier and more strongly

(d) The FK redesign is aligned with our objectives to focus on reliability (by introducing a solution quickly), to increase competition in ancillary service markets and to build additional value streams for flexibility.

3.35. Although there are benefits to the new proposed solution, we recognise that the information to the market may not be as transparent as our initial proposal, as a separate price signal for standby reserve will not be produced.

3.36. We note that this is similar to the Australian Energy Market Commission's (AEMC) recent decision to not implement an operating reserve market.[27] In Australia's NEM, participants make their own commitments to keep capacity in reserve, based on price signals and the risks and operational costs associated with running their plant. They have market arrangements in place to price the need for energy and frequency control, but they do not explicitly price standby reserves.

3.37. AEMC has recently considered the need to explicitly value provision of standby reserves through an operating reserve market. While an operating reserve market could provide greater visibility of market participants' reserve decisions helping to manage risks, AEMC considers that it will not offer any material performance improvements relative to their current arrangements and will introduce significant additional costs for the market. Instead, AEMC supports publishing additional information on energy availability such as state of charge for batteries, daily energy constraints for other scheduled plant types and maximum storage capacity.

3.38. In our consultation paper we noted we would assess the option of an integrated standby ancillary service and any potential interim options against a set of evaluation criteria. Other proposals in this decision paper will be subject to a similar level of analysis once they are ready for consultation.

3.39. We have therefore assessed the five-minute variability tool (stage 1) against the evaluation criteria (Table 2). See the section starting at paragraph 3.109 for more information on our assessment of the evaluation criteria.

Table 2: Authority's assessment of the five-minute variability tool against the evaluation criteria.

Evaluation criteria	Authority's view
Improve information availability	A five-minute variability product will not provide a separate price signal for standby reserves but will improve existing price signals.
Better align incentives on purchasers and operators	A five-minute variability product will provide additional incentives for generators and new flexibility providers to provide flexibility services. It will align incentives for purchasers by allocating the costs to causers of variability.
Minimise risk of unintended consequences	A five-minute variability product is already used in the form of MFK, so there are no risks with introducing a 'new'

[27] AEMC, *Rule determination. National Electricity Amendment (Enhancing reserve information final determination) Rule 2024.* March 2024, 21. https://www.aemc.gov.au/sites/default/files/2024-03/Enhancing%20reserve%20information%20final%20determination.pdf

Evaluation criteria	Authority's view
	product – the performance of the product is already well known.
Can be modified or removed or act as an enabler of future development	Stage 1 is an enabler for other technologies, such as BESS and DR to participate in new ancillary service markets.
Aligns with net zero 2050 target	With increased penetration of variable renewable generation as the country transitions to electrification, this solution will support the changing generation mix by providing a form of standby reserves as a buffer against short-term variations.
Meets statutory objective	We believe this solution is for the long-term benefit of consumers as: • it will promote competition in the ancillary service market by opening up participation to other types of technology • it will redefine an existing ancillary service to specifically address reliability risks from a sudden drop in intermittent generation • it allows for efficient allocation of resource. Resource providers will be able to offer their resource for multiple uses and the system operator's tools will choose the most efficient allocation. In addition to promoting competition, reliability and efficiency, this solution will reduce costs by repurposing existing tools.

3.40. We will start work with the system operator in July 2024 to redefine the existing MFK product into a five-minute variability tool. In addition to operational process changes, this work would require a change to the system operator's procurement plan and policy statement (documents incorporated by reference in the Code). Any proposed changes to these documents would be released for, and subject to, consultation prior to implementation in accordance with the requirements set out in the Code (clauses 7.13 to 7.22).

The Authority will undertake work to enhance dispatchable demand

3.41. Demand response from consumers will play a crucial role in managing security of supply while also providing downward pressures on spot prices. Improving demand response participation in the market is a key priority for the Authority, and we are working through a full range of options to accelerate demand response from consumers of all sizes.

3.42. We will undertake work to enhance DD participation in the wholesale market by investigating how to reduce technical barriers to entry. We will also build additional value streams for demand response in the wholesale market by investigating opening other ancillary services to demand response. We recognise that demand response is a likely source of flexibility in the immediate to short-term.

3.43. We will also continue to work with industry to facilitate demand response from small consumers and aggregators (flexibility providers). This will include exploring a full range of levers to accelerate demand response in the market including trials and regulatory sandboxes to discover and remove technical and regulatory barriers to entry.

Summary of option to enhance DD:

3.44. DD allows large consumers to participate in the electricity market and to compete with generators to set the spot price and be able to respond more efficiently to wholesale market conditions. DD participants must respond to dispatch instructions from the system operator. They are not paid to reduce demand, but they are paid constrained on and constrained off payments to compensate for scenarios where the final spot price is higher or lower than the bid price.

3.45. Our consultation paper described two possible enhancements that could address operational concerns to DD participation in the wholesale market:

(a) Applying a ‘return time’ constraint to DD. This would allow a DD participant to signal to the system operator a minimum return time from their dispatch off. Some industrial processes must remain off for a period before they can be restarted for plant or personnel safety reasons.

(b) Applying ramp rates to dispatchable demand bids. Ramp rates are currently applied to generator offers to reflect the operational capability of generation plant. Applying ramp rates to dispatchable demand bids would allow a DD participant to reflect any operational shut-down or start-up procedures that would limit its ability to meet a dispatch instruction within the five-minute dispatch period.

What submitters said:

3.46. Most submitters strongly supported the need to accelerate demand response.

3.47. However, many submitters including Business Energy Council, Enel X, MEUG, Fonterra, New Zealand Steel, Mercury and WEL Networks noted that due to the lack of meaningful financial incentives, demand response may not materialise at the pace required to manage short term risks.

3.48. These submitters supported the introduction of payments to reward demand response. Fonterra suggested that DD participants should be paid the spot price for any demand response that has been bid into the market and subsequently dispatched. This is to take into account fuel costs of switching operational modes (eg, moving from an electrode boiler to a biomass boiler) and opportunity costs through lost production. Fonterra also noted the costs incurred to install the ability to provide demand response.

3.49. Both Enel X and SolarZero agreed on the importance of demand response to address peak capacity issues. However, they stated that current mechanisms to enable their participation in the market – dispatch notification and dispatchable demand – are not enough. Enel X noted that the benefits rarely outweigh the costs, complexity and risks of participating**.** SolarZero commented on the long timeframes needed to change the Code to better enable distributed energy resources participation in the market.

3.50. Intellihub said that financial incentives alone will not enable distributed energy resources participation and cite technical barriers, such as technology and market integration issues.

3.51. MEUG, Business Energy Council, Northpower, Fonterra and Vector also suggested that the removal of the Regional Coincident Peak Demand (RCPD) signal exacerbated issues associated with peak demand. This is because RCPD used to provide a price signal to distributors to manage their loads, which assisted with the matching of supply and demand.

The Authority's response

3.52. We acknowledge the support for demand response, and we are committed to enhance its participation in the market to promote both competition and flexibility.

3.53. We also recognise that consumers of different sizes (including services provided by aggregators) have different incentives and mechanisms to provide demand response. This paper outlines our decision to promote more demand response from large consumers.

3.54. However, small-to-medium sized consumers can also play an important role in managing peak demand. We consider that signals from peak pricing need to flow to consumers so that consumers can benefit from shifting demand and reducing their costs.[28] Retailers are already realising the benefits of reduced costs at peak by bringing demand control into their portfolios. The next step is to signal this demand response to the market for improved coordination. We will continue to explore solutions to accelerate the process to signal this demand response in the market.

3.55. We have other work programmes in place to promote demand-side flexibility at the retail and distribution level. An example is our distribution pricing work to speed up distribution pricing reform[29] so that consumers can realise benefits from avoiding peak periods. Another example is our recent decision to amend the Code[30] to allow aggregators of distributed energy resources to participate in the wholesale market.

3.56. We considered feedback calling for financial incentives, such as 'negawatt' type schemes, to accelerate demand response. Negawatt payments are payments at the wholesale price for electricity not consumed. MDAG's report provides a considered analysis of negawatt schemes.[31] They do not favour an administered demand

---

[28] Edmunds, S, *Win-win' for power: Bills can drop by 20%, Consumer says*. April 2024, 14. https://www.stuff.co.nz/money/350244234/win-win-power-bills-can-drop-20-consumer-says

[29] Electricity Authority, *Distribution pricing.* *https://www.ea.govt.nz/projects/all/distribution-pricing/*

[30] Electricity Authority, *Decision on dispatch notification enhancement and clarifications*. January 2024, 26. https://www.ea.govt.nz/news/general-news/decision-on-dispatch-notification-enhancement-and-clarifications/

[31] MDAG, *Price discovery in a renewables-based electricity system: Final Recommendations Paper.* December 2023, 19. https://www.ea.govt.nz/documents/4335/Appendix_A2_-_Final_recommendations_report.pdf (Page 175)

response payment scheme, but instead recommend activating market driven demand-side flexibility (DSF). Their reasons include:

(a) the significant cost, complexity and risk in designing and implementing a negawatt scheme in a way that integrates with the New Zealand electricity market design

(b) such mechanisms are not equivalent to typical market instruments (eg, full spot exposure, or contract for difference (CfD)) and, at best, approximate wholesale incentives for DSF. They can inefficiently incentivise DSF, can be gamed, and thus risk inefficient deployment of DSF and lower the liquidity of tradeable market instruments.

(c) negawatt payments amount to a distortion. They provide the 'benefits' of reduced demand in high price periods as if it were a CfD arrangement, but not the downsides of a CfD contract (ie, payments back to the counterparty during low price periods, or the spot cost of increased consumption over the contract level).

(d) incentives for DSF are still present in a range of situations and there is no evidence that the retail market is blocking the development of tariffs which reward DSF. There are alternative ways to make DSF commercially attractive that are not reliant on negawatt schemes.

3.57. We agree with MDAG's assessment of negawatt schemes and providing payments for demand response. While some submitters were concerned that demand response may not materialise at the pace required to manage short term risks, we note that there are many examples of demand-side flexibility starting to emerge that indicate that other participants are incentivised to offer demand-side flexibility agreements. We have started a range of measures to track the degree to which demand-side flexibility is opening up in the marketplace and to assess the pace of DSF uptake.

3.58. Recent examples of emerging market-driven trials and agreements indicate that DSF is continuing to develop for consumers of different sizes. These examples include:

(a) Meridian's announcement to investment in the development of demand response retail products in the near future[32]

(b) Meridian has also recently implemented a new peak demand response agreement with the New Zealand Aluminium Smelter covering a 12-week period for winter 2024. The agreement allows Meridian to require the smelter to reduce its consumption of electricity by up to 20MW, over four trading periods a day, and up to 20 trading periods over a fortnight. This is in addition to the existing agreement that allows Meridian to require the smelter to reduce its consumption of electricity by up to 50MW[33]

[32] Meridian. *Interim results and reports.* February 2024, 28. https://www.meridianenergy.co.nz/public/Investors/Reports-and-presentations/Interim-results-and-reports/2024/Meridian-half-year-results-2024-transcript.pdf

[33] Meridian. *Interim results and reports.* February 2024, 28. https://www.meridianenergy.co.nz/public/Investors/Reports-and-presentations/Interim-results-and-reports/2024/Meridian-half-year-results-2024-transcript.pdf

(c) Contact, Mercury and Meridian's new agreements with the New Zealand Aluminium Smelter, with expanded demand response provisions for up to 185MW[34]

(d) Mercury's electric vehicle (EV) smart charge trial, which tests a smart charging system that makes way for two-way communication between EVs and the grid to optimise when the EVs are charged, according to grid conditions[35]

(e) Simply Energy's retail energy services, which let consumers earn money for switching off selected electrical equipment at peak times and for being on standby to reduce electrical load quickly if there's an unplanned major grid event[36]

(f) Contact Energy's time of use plans, which offer free electricity at specific off-peak times (between 9pm to midnight or 9am to 5pm on the weekends) or half price power to recharge EVs between 9pm and 7am[37]

(g) Octopus Energy's plan that will pay 20 cents per kWh (double the off-peak rate) to consumers with a battery for exporting power to the grid during peak demand times. For this winter's peaks, Octopus is doubling this rate again to 40 cents per kWh[38]

(h) Octopus Energy's savings sessions that pay customers $2 for every kWh of electricity they reduce at times when there is high electricity demand.[39]

3.59. These offerings are effective at encouraging consumption away from peak demand periods or the use of domestic BESS to provide system support when it is needed most. Not only do these agreements encourage demand shifting away from peak demand periods, but they also provide direct savings to consumers.

3.60. As noted earlier, we have started a range of measures to track the degree to which demand-side flexibility is opening up in the marketplace. An example is our work to improve retail market monitoring[40] and our recent DSF survey.[41] This work is aligned with MDAG recommendation 3 – monitor provision and uptake of DSF rewarding activity (including tariffs). As we progress our work programme, we will assess the availability of demand-flexibility and whether implemented measures are working, the pace of these developments and whether any further changes are needed to accelerate their development.

---

[34] Energy News. *Tiwai deal a boon for investment, electricity market - Forbar*. June 2024, 5. https://www.energynews.co.nz/news/electricity/160242/tiwai-deal-boon-investment-electricity-market-forbar

[35] Mercury. *Plug into tomorrow, join our trial.* https://www.mercury.co.nz/ev-smart-charge-trial

[36] Simply Energy. *It pays to be flexible with your energy use.* https://simplyenergy.co.nz/demand-flexibility/

[37] Contact. *Good plans that work around you. https://contact.co.nz/residential/good-plans*

[38] Octopus. *Peak export rate 40ckWh 1 June – 31 August.* https://octopusenergy.nz/octopuspeaker

[39] Octopus. *Saving sessions.* https://octopusenergy.nz/saving-sessions

[40] Electricity Authority. *Improving retail market monitoring. https://www.ea.govt.nz/projects/all/improving-retail-market-monitoring/*

[41] Electricity Authority. *How demand-side flexibility can contribute to security of supply*. https://www.ea.govt.nz/news/eye-on-electricity/how-demand-side-flexibility-can-contribute-to-security-of-supply/

3.61. We also agree there is potential for negawatt schemes to be gamed, and we note the recent problems in US jurisdictions and the costs to consumers.[42]

3.62. Countries that have introduced payment mechanisms, such as Australia and the USA, principally did so due to the slow development of market-driven mechanisms and the lack of wholesale market access pathways for demand response.

3.63. We acknowledge concerns that the removal of RCPD has contributed to the apparent upward trend in peak demand and this is supported by our analysis.[43] We estimate that removing the RCPD charge increased daily peak consumption by around 150MW during the top 300 consumption periods in 2022. We anticipated this impact ahead of winter 2023, and we encouraged distributors to set prices reflecting congestion on their own networks as part of the move to more efficient distribution pricing.

3.64. The system operator also applied a sensitivity to the 2023 security of supply assessment (SOSA) to reflect the impact of RCPD removal on peak demand.[44] However, they note that from 2024 the RCPD sensitivity realigns with the reference case. This means that the impact of RCPD removal is not anticipated to persist in a way that impacts winter capacity margins into future years. The draft SOSA for 2024 does not contain a sensitivity for RCPD removal.[45]

3.65. However, as noted in past papers, the systems used to manage load by distributors (eg, ripple control hot water systems) are still in place and unlikely to be decommissioned in the near term.[46] We recently decided to amend the Code to permanently implement Option E of the winter 2023 initiatives (clarify availability and use of 'discretionary demand' control).[47] This initiative has been useful for identifying the availability of controllable load since the initiative was first introduced (on a temporary basis) in May 2023.

---

[42] For more details see *FERC enforcement office seeks $27M from Ketchup Caddy for MISO demand response fraud* (Utility Dive, February 2024, 22) https://www.utilitydive.com/news/ferc-enforcement-ketchup-caddy-miso-market-manipulating/708183/?utm_source=Sailthru&utm_medium=email&utm_campaign=Newsletter%20Weekly%20Roundup:%20Utility%20Dive:%20Daily%20Dive%2002-24-2024&utm_term=Utility%20Dive%20Weekender) and *NIPSCO, Linde to pay $66.7M to settle charges for gaming MISO demand response program* (Utility Dive, January 2024, 8) https://www.utilitydive.com/news/nipsco-linde-ferc-miso-demand-response-settlement/703888/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202024-01-08%20Utility%20Dive%20Newsletter%20%5Bissue:57944%5D&utm_term=Utility%20Dive)

[43] Electricity Authority, *The impact of the RCPD charge removal on peak demand.* March 2023, 21. https://www.ea.govt.nz/projects/all/impact-of-the-rcpd-charge-removal/#:~:text=We%20estimate%20that%20removing%20the,300%20consumption%20periods%20in%202022.

[44] Transpower*, Draft Security of Supply Assessment 2023.* June 2023, 26. https://static.transpower.co.nz/public/bulk-upload/documents/2023%20SOSA%20-%20Final%20Report%20-%20Final%20Version.pdf?VersionId=3VV75p2zXTR_3kxn3HZPixEiiq9ipiJX

[45] Transpower*, Draft Security of Supply Assessment 2024.* May 2024, 7. https://static.transpower.co.nz/public/bulk-upload/documents/2024%20SOSA%20-%20Draft%20Report%20-%20Consultation%20Version.pdf?VersionId=_Dtebn49RtS5evJIhK6i265_bIYQTeTf

[46] Electricity Authority. *Driving solutions to promote consumer interests through winter 2023.* March 2023, 9. https://www.ea.govt.nz/documents/2102/Driving-efficient-solutions-to-promote-consumer-interests-through-winter-2023-_D28umrs.pdf

[47] Electricity Authority, *Code amendment omnibus two.* March 2024, 28. *https://www.ea.govt.nz/documents/4747/Code_amendment_omnibus_two_decision_paper.pdf*

3.66. Our DSF survey[48] and other recent public announcements also indicate that hot water control is moving from distributors to retailers. Recent examples include:

(a) Contact Energy's 'hot water sorter'[49]

(b) Octopus' hot water trial.[50]

3.67. This shift suggests the emergence of market-based mechanisms to incentivise this form of load control and to share the benefits directly with consumers.

3.68. Alongside the traditional time-of-use pricing schemes employed by distributors to signal their sensitivity to network capacity issues to commercial and industrial consumers, we encourage the wider use of demand shifting tariffs to better manage demand peaks.[51] This issue is being discussed as part of the distribution pricing reform programme.[52]

3.69. In summary, we note the emergence of market driven DSF tariffs and retail offerings and will continue to monitor and support their development. We will also trial new ways to accelerate their participation in the market.

3.70. As part of our work to encourage more demand response at the wholesale level for large consumers, we have decided to undertake further work to enhance dispatchable demand participation in the wholesale market. We continue to receive enquiries from market participants who are interested in pursuing DD, despite feedback received from other participants regarding financial incentives.

3.71. The next step for this work is to further develop the high-level concepts outlined in our consultation paper.

3.72. We will use the feedback provided in submissions to help form our proposals. We will also engage with DD operators to learn more about their experience with DD and to further develop our policy solutions.

3.73. We will consult on the proposed DD enhancements once they have been sufficiently developed. We aim to complete the policy development for this work by mid-2025. Implementation times are subject to further discussion with the system operator.

The Authority will undertake work to enhance BESS participation

3.74. We will undertake work to enhance BESS participation in the wholesale and instantaneous reserves market by improving the modelling of BESS in the market system and simplifying the offer forms for BESS.

---

48 Electricity Authority. *How demand-side flexibility can contribute to security of supply*. June 2024, 26. https://www.ea.govt.nz/news/eye-on-electricity/how-demand-side-flexibility-can-contribute-to-security-of-supply/

49 Scoop. *Contact empowers kiwis to make positive changes to their energy habits.* April 2024, 12. *https://www.scoop.co.nz/stories/BU2404/S00162/contact-empowers-kiwis-to-make-positive-changes-to-their-energy-habits.htm#:~:text=By%20making%20a%20small%20change,Chief%20Retail%20Officer%20Matt%20Bolton.*

50 Octopus. *Hacking hot water to save money. https://octopusenergy.nz/blog/hacking-hot-water-to-save-money*

51 Electricity Authority. *Targeted Reform of Distribution Pricing, issue paper.* July 2023, 5. https://www.ea.govt.nz/documents/3367/Issues_Paper_-_Target_reform_of_Distribution_Pricing.pdf

52 Electricity Authority. *Distribution Pricing Reform: Next steps.* May 2024, 7. *https://www.ea.govt.nz/documents/4821/Distribution_Pricing_Reform_-_Next_steps.pdf*

3.75. We will also build additional value streams by seeking to open other ancillary services to BESS participation. We recognise that BESS is a likely source of flexibility in the immediate to short-term, and we consider that the market system should be prepared to accommodate the significant amount of BESS in the investment pipeline.

Summary of option to promote BESS:

3.76. BESS can currently participate in the wholesale and instantaneous reserves markets, although the method of participation is cumbersome. Our consultation paper described our proposal to introduce a bi-directional offer form for BESS to allow BESS to participate more efficiently in the wholesale and ancillary service markets. A bi-directional offer form would allow for the market system to optimise between charging and discharging modes as well as remove the risk of inconsistent combinations or energy and instantaneous reserve being dispatched.

What submitters said:

3.77. Most submissions supported our proposed focus to improve market participation for BESS in the short-term.

3.78. NewPower agreed that the current participation methods for BESS in the wholesale and ancillary markets are currently very complex and require a great deal of effort to ensure that bids and offers are consistent. They believe that this will be a significant barrier to entry for smaller scale BESS if the problem is not addressed.

3.79. Vector supported the idea of a bi-directional offer form, but cautioned the Authority to make sure that the Code is developed in such a way that the approach can be leveraged by other emerging technology such vehicle-to-grid capability.

3.80. Mercury considers that, at the present time, BESS and demand response are not equivalent to thermal generation for managing security of supply. The Business Energy Council noted that BESS could provide cover for short durations of imbalances between supply and demand, but that the capacity provided is limited over prolonged periods of windless conditions.

3.81. OMV did not support our proposed focus on BESS and said that we should apply a wider lens to the problem of peak capacity shortfalls, and we should not favour particular technologies.

3.82. WMAC.Cloud, Wellington Electricity, Dr David Hingston and the Business Energy Council said that we should focus on accelerating participation of demand response as priority over BESS.

The Authority's response

3.83. We are committed to promoting both competition and flexibility in the wholesale and ancillary service markets. We see that BESS will play an increasingly key role in firming intermittent generation as more BESS enters the market. As mentioned in paragraph 2.11, there is significant BESS in the investment pipeline.

3.84. This scenario is already playing out overseas. In the US, large batteries are already playing a key role in stabilising the grid and 'delivering solar power after dark'.[53] The Australian Energy Market Operator (AEMO) is also working on solutions to better integrate grid-scale batteries into the NEM. To date, grid-scale batteries in Australia account for approximately 1.4 gigawatts (GW) of storage capacity and help the country harness its abundant solar resources.[54]

3.85. We recognise the importance of this flexibility to support security of supply and will develop work to enhance both BESS and DD participation in parallel with the other initiatives mentioned in the section starting at paragraph 2.38. See the section starting at paragraph 3.41 for more information on our initiatives to promote demand side flexibility.

3.86. Enhancing BESS participation is also important to promote competition. By reducing the complexity of offering BESS into the market, we can reduce barriers to entry for BESS. We believe it is prudent to address these complexities now before they become a significant issue for future BESS operators.

3.87. With simplified participation in the wholesale market, we can investigate opening further ancillary services thus providing additional revenue streams to BESS operators. This will provide additional incentives to invest in BESS and provide additional flexibility to the wholesale market. Paragraph 3.32(j) outlines our proposal to investigate opening up other ancillary services (five-minute variability management and frequency keeping) to BESS participation.

3.88. We agree that the Code will need to be developed carefully so as not to limit future technologies and note that the Code is currently worded more broadly to reference energy storage systems (ESS) rather than BESS.

3.89. We are also preparing a consultation paper to ensure the workability of the TPM for emerging technologies such as BESS. This paper will focus on the treatment of these technologies for connection charges at shared connection assets for the annual adjustments to the residual charge.

3.90. We expect that BESS will rapidly find valuable application at all levels in the power system, from the grid to distribution networks, and embedded within consumer premises.

3.91. The next step for this work is to further develop the high-level concepts outlined in our consultation paper.

3.92. We will use the feedback provided in submissions to help form our proposals. We are engaging with BESS operators and with AEMC and AEMO to learn more about their experience with BESS and to further develop our policy solutions.

3.93. We will consult on the proposed BESS enhancements once they have been sufficiently developed. We aim to complete the policy development for this work by mid-2025. Implementation time will depend on the final policy design, although we

[53] The New York Times. *Giant Batteries Are Transforming the Way the U.S. Uses Electricity*. May 2024, 7. https://www.nytimes.com/interactive/2024/05/07/climate/battery-electricity-solar-california-texas.html?searchResultPosition=1

[54] AEMO. *Market trials prepare industry for grid-scale battery integration*. May 2024, 15. https://www.aemo.com.au/newsroom/news-updates/market-trials-prepare-industry-for-grid-scale-battery-integration

note that BESS can already participate in the market. This work will improve business cases and confidence to proceed with future BESS investment.

The Authority will start the high-level design for standardised flexibility products

3.94. We will start the high-level design for new standardised flexibility products. This work is intended to enhance forward price discovery in flexibility markets and is aligned with MDAG recommendation 8 – develop standardised flexibility product(s) (including DSF).

Summary of financial options to promote flexibility:

3.95. Our consultation paper included the Australian National Electricity Market's 'super peak swap' product as an example of such a product. This product is designed to provide cover during high demand periods (peaks) but provide no volume cover during lower demand periods. This would allow flexible supply and demand side flexibility to participate in the forward price discovery process and obtain more certain revenues while supporting the management of peak demand.

3.96. We also noted MDAG's recommendation to enhance price discovery by requiring market making in flexibility products (recommendation 24). In our consultation paper, we asked whether there is a case for accelerating the introduction of market making obligations to further support the development of flexible resources in the wholesale market.

What submitters said:

3.97. There was some support for the development of standardised flexibility products.

(a) Around a third of submitters supported this proposal, with NewPower and the Independent Retailers noting that financial super peak hedges should be developed urgently. Enel X said that it would be useful to manage uncertain revenue streams and give confidence to consumers. Nova noted that such products should be supported by uncommitted thermal generation.

(b) Alpine Energy and Meridian, while supporting the product, believed it would require careful design and consideration.

(c) Mercury, Wellington Electricity and Fonterra did not support the proposal. Mercury does not believe there is value in such products at this time and supports improved disclosure and monitoring of the over the counter (OTC) market in order to gain better insights for future products. Wellington Electricity is concerned that there is insufficient market penetration across industry participants. Fonterra said that cap or peak products do not make financial sense and it is more prudent to purchase flat products.

3.98. There was less support for mandated market making for flexibility products.

(a) The Independent Retailers noted that an efficient hedge market is a key pillar for a well-functioning wholesale market and believe that mandatory market making should be expedited as a top priority along with the development of standardised flexibility products.

(b) NewPower also commented that mandatory market making is essential to assure liquidity for any flexibility products. WEL Networks expressed a similar view.

(c) Contact, Genesis, Mercury, Meridian and Wellington Electricity did not support mandatory market making. Concerns raised included the high costs of such an intervention. Mercury, ERANZ and Manawa noted that a cost-benefit analysis would need to be done first to justify the need.

The Authority's response

3.99. We are committed to implementing MDAG's recommendation 8 – new flexibility products (standardised). The project, supported by industry co-design, will begin in mid-2024. This project will focus on development of the product with industry consensus.

3.100. Liquidity is an essential part of success, as highlighted by the submissions from the Independent Retailers and NewPower. The industry co-design process, supported by the analysis already undertaken by MDAG, seeks to find common ground that supports the development of voluntary liquidity. This would mitigate some of the concerns raised by Wellington Electricity as the contract could be traded OTC. MDAG has also specified a contingent recommendation 24 (market making in flexibility products) in the event of insufficient competition in the flexibility segment.

3.101. The (Standardised) Flexibility Contract project has started. Should industry consensus not be reached, we intend to propose a specific product as a backstop. The product could be traded OTC and via brokers or niche platforms in its initial stages. Should voluntary competition in flexibility be assessed to be poor using the Competition Dashboard (MDAG recommendation 12), mandated market making of the product will be considered (MDAG recommendation 24).

3.102. We are broadening hedge disclosure obligations to enhance transparency and facilitate the ongoing monitoring of evolving futures markets. Our recent decision paper on *Improving hedge disclosure obligations* highlights how this work will support efficient prices for consumers and help participants to better manage risk and drive investment in electricity generation and storage.[55]

The Authority will not implement any of the interim solutions

3.103. We have decided to not implement any of the interim solutions described in the consultation paper. Instead, we believe the measures discussed in previous sections will better support security of supply over the long-term.

Summary of interim solutions:

3.104. We consulted on the following interim solutions:

(a) **Option 1: Contracts for out-of-market resource**

Separate payments outside the spot market could be used to encourage providers to make more resource available. For example, the system operator could contract with resource providers to make additional resource available

[55] Electricity Authority, *Improving hedge disclosure obligations*. June 2024, 6. https://www.ea.govt.nz/documents/5051/Decision_paper-_HDO_Improvements.pdf

at times, such as when there is a low residual situation, in return for a predefined contract payment.

(b) **Option 2: Out-of-market tender for emergency demand response**

This option is similar to option 1 but is ring-fenced to demand response that is not currently offered into the market.

(c) **Option 3: Provide payments to participants to commit their resources to the market**

This option would provide payments for any uncleared energy or reserve offers, including any firming dispatchable demand that is not dispatched (for energy or interruptible load). The intent of this option is to provide incentives for participants to commit their full capacity to the market. We proposed three variations of this option:

(i) variation a: Pay for the 200MW residual

(i) variation b: Pay for *all* available residual capacity

(i) variation c: Pay for all available residual capacity – dispatchable demand only.

What submitters said:

3.105. There was mixed support for out-of-market solutions (interim options 1 and 2) and very little support for residual payments (interim option 3).

3.106. **Option 1: Contracts for out-of-market resource**

(a) Submitters who supported this option generally agreed that this option was less desirable than in-market solutions. However, they provided several reasons why it should be pursued and ways to minimise its potential risk.

(b) The Business Energy Council recognised the potential of this short-term solution to quickly address capacity issues, but also acknowledged its risks. Transpower supported this option as a prudent backstop option that could prevent having to design something from scratch at a short notice. Genesis also noted that a time bound and well-designed option that can be quickly implemented, if required, does not necessarily lead to distortion of long-term price. Similarly, WEL Networks suggested an iterative process could help address uncertainties and costs. Intellihub suggested that out-of-market contracts may be the most efficient way of procuring a peak capacity management service while waiting for an in-market solution.

(c) Enel X and SolarZero strongly supported this proposal and commented that this solution could promote innovation and support demand response and BESS. Enel X suggested the Australian short-notice Reliability and Emergency Reserve Trader (RERT) and the non-co-optimised essential system services (NCESS) mechanisms as examples of successful out-of-market mechanisms.

(d) The Consumer Advocacy Council, Nova, Independent Retailers, Meridian and Mercury did not support this option. In particular, the Consumer Advocacy Council noted that each interim options had the potential to add significantly to the price consumers, at a time when living costs continue to rise. Nova and

Meridian also agreed with the Authority's assessment that the costs and risks associated with this option outweighed its benefits. Meridian also reiterated that all interim options were likely to: be distortionary, be inefficient, add costs to consumers, and risk significant unintended consequences by undermining the current market design.

3.107. **Option 2 – Out-of-market tender for emergency demand response**

(a) Mercury and Vector emphasised how this could be a positive option to promote more demand response by providing a financial incentive to participate in the market. SolarZero and Enel X also commented that this solution could be a quick and cost-effective way to support innovation and address capacity issues.

(b) Many supporting submitters (such as WEL Networks, Transpower and Vector), however, also saw this mechanism as temporary, due to its potential long-lasting negative impacts.

(c) Submitters who did not support this option (such as the Consumer Advocacy Council, ERANZ, Meridian, Fonterra, Contact Energy, and Orion) were concerned about costs to consumers and the potentially distortionary effects to price signals.

3.108. **Option 3 – Provide payments to participants to commit their resources to market**

(a) Transpower and the Business Energy Council were the only submitters to support this option. They both also acknowledged the potential negative impacts of this option. However, Transpower suggested this mechanism could be considered as an insurance payment with a sunset clause to limit its negative impacts.

(b) Submitters who did not support this option noted that they preferred other proposed options such as integrated solutions (ERANZ) or out-of-market mechanisms (Enel X).

The Authority evaluated each interim option against a set of criteria

3.109. We investigated these interim options as we acknowledge the concerns regarding security of supply and recognise the desire to have a contingency plan in the short-term while new generation and flexibility emerges.

3.110. Our overarching objective is to ensure that any changes are for the long-term benefit of consumers. With this in mind, we evaluated interim options based on the extent to which they:

(a) improve the information available to customers and operators to make efficient contracting and resource commitment decisions

(b) better align the incentives on purchasers and operators with the interests of end-use consumers

(c) risk unintended harmful side-effects for consumers, such as weakening current incentives to make investments in flexibility resources, or contract to provide flexibility

(d) can be modified or removed if they do not provide net benefits

(e) align with the government's 2050 net zero climate change targets

(f) can be implemented for winter 2024[56]

(g) meet the Authority's statutory objective.

3.111. We received feedback from submitters on our evaluation criteria. While some submitters agreed with our criteria, other submitters noted that the evaluation criteria should:

(a) explicitly recognise the outcomes that consumers expect from the electricity system. This includes recognising the risk of unintended harmful side effects on the quality of supply for all consumers

(b) be technology neutral

(c) more clearly reflect the government's strategy

(d) recognise that there can be unintended consequences from doing nothing and letting problems continue or get worse.

3.112. In response to this feedback, we note that ensuring consistency with our statutory objectives remains the key evaluation criterion we will use to assess any potential options. The other criteria help us further assess the merit of any potential solution within this context.

3.113. We have decided to keep the proposed evaluation criteria but have incorporated submitters' views into our assessment of the criteria where appropriate.

3.114. We have assessed interim options 1 and 2 (out-of-market contracts) against the evaluation criteria (Table 3). We have also added an additional evaluation to consider how these options would have performed in response to the low residual situation of 10 May 2024. See Appendix B for more information on the events of 10 May 2024.

Table 3: Authority's assessment of out-of-market contracts against the evaluation criteria

Evaluation criteria	Authority's view
Improve information availability	Out-of-market contracts do not improve information availability as the costs are not immediately visible to the rest of the market at the time of procurement.
Better align incentives on purchasers and operators	Out-of-market contracts reduce incentives on participants to manage their own risk and places the burden on consumers by socialising the risk (and costs).
Minimise risk of unintended consequences	Out-of-market contracts have significant potential unintended consequences. Such an intervention would distort the spot price and price signals which carry the risk of chilling investment and undermining confidence in the market as a whole.

[56] We did not apply this criterion to our assessment of a five-minute variability tool.

Evaluation criteria	Authority’s view
	Any out-of-market product would be in competition with the pipeline of new initiatives to assist with demand response. However, this needs to be balanced against the risk of unintended consequences from interruptions to electricity supply should other market-driven solutions not emerge at the pace required. These unintended consequences include loss of confidence in the electricity market.
Can be modified or removed or act as an enabler of future development	Out-of-market contracts would be difficult to remove. Once in place, the problem becomes self-reinforcing and becomes a year-on-year problem. There may be pressure every year to intervene (especially if investment is disincentivised).[57] While out-of-market contracts could be an effective enabler for innovation, especially for demand response, they are not the only mechanism available to promote innovation and future development.
Align with net zero by 2050 target	Out-of-market contracts that include thermal generation could be seen as a subsidy to extend the use of thermal plant. However, we do recognise that thermal generation currently plays an important role in security of supply. On the other hand, out-of-market contracts that include demand response will support net zero goals by acting as an enabler for greater participation of discretionary demand in future demand response markets.
Can be implemented for winter 2024	Out-of-market contracts would require amendments to the Code to allocate the costs of the contract. Amendments would also be required to the policy statement and procurement plan (documents incorporated by reference in the Code) to allow the system operator to procure such a service. Time would also be required to go through the required procurement process. It may have been possible to have implemented this option in time for winter 2024 if progressed as an urgent Code amendment, but timelines would have been tight.
Meets statutory objective	These options may have short-term benefits for reliability, but this is not guaranteed. For example, there is a risk that units may fail on start-up or that commercial concerns for industrial demand response may limit their availability when needed.

[57] Electricity Authority. *Ensuring an orderly thermal transition.* June 2023, 6. https://www.ea.govt.nz/documents/3148/Ensuring_an_Orderly_Thermal_Transition_6_June_20231397102.1_1.pdf

Evaluation criteria	Authority's view
	We believe these solutions are not in the long-term benefit for consumers as: • they do not promote competition or efficiency in the market (by definition, they promote out-of-market products) • they do not promote accurate price signals and may disincentivise investment. Decisions on non-committed investment could be delayed or curtailed • there is little to no cost control as the products are not subject to the same competitive tensions as market products. We estimate the cost to consumers to be at least $48 million per annum.[58] Overseas experience has shown that costs for such products can rapidly escalate after the initial procurement process.[59]
Assessment against 10 May 2024	One of the root causes of the 10 May 2024 event was the large number of generation units on outage. Out-of-market contracts could have been successful at ensuring sufficient generation was on standby, but it would depend on the contract period. If the contract term was for winter months, the contract would not have made a difference to the situation. It is more likely that emergency demand response would have been available to respond, but this would also depend on the contract period. Out-of-market contracts for additional resource would still have had the effect of suppressing the spot price.

3.115. Contracts for out-of-market resource (interim options 1 and 2) may be well-intentioned but are unlikely to be effective at providing additional resilience in the short term to manage peak capacity issues, and they would be a significant departure from the current market and carry a number of major risks. For these reasons, we have decided not to progress out-of-market contracts, even as insurance policies.

3.116. We have assessed interim option 3 (residual payments) against the revised evaluation criteria and for its potential effectiveness against the events of 10 May 2024 (Table 4).

[58] Electricity Authority, *Consultation paper potential solutions for peak electricity capacity issues: Appendix B.* January 2024, 12. https://www.ea.govt.nz/documents/4382/Appendix_B__Review_of_international_experience.pdf

[59] Electricity Authority, *Consultation paper potential solutions for peak electricity capacity issues: Appendix B.* January 2024, 12. https://www.ea.govt.nz/documents/4382/Appendix_B__Review_of_international_experience.pdf

Table 4: Authority's assessment of residual payments against the evaluation criteria

Evaluation criteria	Authority's view
Improve information availability	Paying for residual does not provide any additional information to the market.
Better align incentives on purchasers and operators	Paying for residual does not necessarily incentivise participants to manage their own risk. There is insufficient evidence to demonstrate whether this option would provide sufficient incentives for participants to commit full capacity at the times required, particularly as we did not receive much feedback on this option.
Minimise risk of unintended consequences	Paying for residual does not distort price signals but may introduce inefficiencies and costs through over-procurement.
Can be modified or removed or act as an enabler of future development	It may be difficult to remove such a scheme because resource providers may argue that existing or new capacity cannot operate without the availability payment and additional resilience provided by the scheme may be considered essential if investment in other technologies has not matched the wider system needs. However, this option could be an effective enabler for innovation by providing an additional revenue stream for flexibility such as BESS and DD.
Align with net zero by 2050 target	With increased penetration of variable renewable generation as the country transitions to electrification, this solution could support the changing generation mix by providing incentives for all technology types to fully commit their resource.
Can be implemented for winter 2024	This option would require amendments to the Code to calculate the price of the residual payment and to allocate the costs accordingly. It may have been possible to have implemented this option in time for winter 2024 if progressed as an urgent Code amendment, but timelines would have been tight.
Meets statutory objective	Residual payments could promote competition as they would be available to all technologies that participate in the market. Residual payments may improve reliability, but it is unclear whether the incentives would be sufficient to encourage enough additional capacity. Payments could incentivise generators to return units from outage more quickly, but it

Evaluation criteria	Authority’s view
	is unclear whether residual payments would be sufficient to address issues surrounding unit commitment of thermal resource. Residual payments (as proposed in the consultation paper) may introduce inefficiencies and additional costs through over-procurement. We believe that residual payments are not for the long-term benefit of consumers as they would impose additional costs to consumers and the benefits of such a scheme are unclear.
Assessment against 10 May 2024	Residual payments could have incentivised generators to return units from outage more quickly, but these units still need to take outages for regular maintenance. We believe that outage coordination would be more effective than residual payments.

3.117. Given the mixed evidence of effectiveness and the lack of support for this option, we have decided not to implement option 3 (residual payments).

3.118. We believe that the measures discussed in previous sections will better support security of supply over multiple time horizons. Although we will not implement the interim options identified in our consultation paper, we will continually look to identify new solutions and improvements to support security of supply. An example is the outage coordination work that we have recently identified.

4. Next steps

4.1. We will continue with our wider programme of work to support security of supply.

4.2. Table 5 below provides a summary of the proposed timing for each initiative.

Table 5: Proposed timing of the Authority’s initiatives

Project	Timing
Improving the accuracy of intermittent generation forecasts	Aim to implement before winter 2025.
Update the SSAD	Aim to update before winter 2025 so that the updated standards inform security assessments for winter 2026 and beyond.
MFK re-specification and enhancement	Aim to complete policy work by the end of 2025. Implementation times are subject to further discussion with the system operator.

Project	Timing
DD and BESS enhancements	Aim to complete policy work by winter 2025. Implementation time will depend on the final policy design.
Develop standardised flexibility products	Aim to have standard flexibility contracts being traded by the end of 2024. This work does not require Code amendments.
Instantaneous reserve cost allocation	Aim to complete policy work by end October 2024 so that the changes can be implemented for winter 2025. Implementation times are subject to further discussion with the system operator and the clearing manager.
Reinforce thermal fuel contract disclosure rules	Aim to implement by end March 2025 ahead of winter 2025.
Outage coordination	This work is subject to scoping before any timeline can be committed.
Further demand-side flexibility enhancements	Aim to have a solution in place by winter 2025. This may be in the form of a trial.

4.3. Where an initiative proposes a change to the Code (or a change to any documents incorporated by reference in the Code), we will consult on the proposed changes before proceeding with implementation.

5. Attachments

5.1. The following appendices are attached to this paper:

Appendix A List of submitters

Appendix B Recent power system events support the need for outage coordination and other enhancements

Appendix C System operator study (TASC 55): MFK Refinement

Appendix A List of submitters

Submitter	Category
Contact Energy	Generator-retailer
Genesis Energy	Generator-retailer
Manawa Energy	Generator
Mercury Energy	Generator-retailer
Meridian Energy	Generator-retailer
Nova Energy	Generator-retailer
Transpower (system operator)	System operator
2 degrees, Electric Kiwi, Flick Electric, Pulse Energy	Independent retailers
Electricity Retailers' Association of New Zealand (ERANZ)	Industry association representing retailers
Alpine Energy	Distributor
Northpower	Distributor
Orion	Distributor
Vector	Distributor
WEL Networks	Distributor
Wellington Electricity	Distributor
Business Energy Council	Industry association representing energy sector and business organisations
Consumer Advocacy Council	Advocate for residential and small business electricity consumers
Dr David Hingston	Private submitter
Early Bardsley	Research associate
Enel X	Flexibility provider
Energy Resources Aotearoa	Industry association representing energy-intensive business
Fonterra	Major electricity user
Institute of Geological and Nuclear Sciences Ltd (GNS Science)	Research institute

Intellihub	Smart utility infrastructure-as-a-service provider
Major Electricity Users’ Group (MEUG)	Commercial industry representative group
Neil Walbran Consulting Ltd	Business consultancy
New Zealand Steel	Major electricity user
NewPower	Owner, operator, maintainer and trader of solar and BESS generation
OMV New Zealand (OMV)	Oil, gas and petrochemical company
SolarZero	Flexibility provider
WMAC.Cloud	Wireless sensors provider

Appendix B Recent events support the need for outage coordination and other enhancements

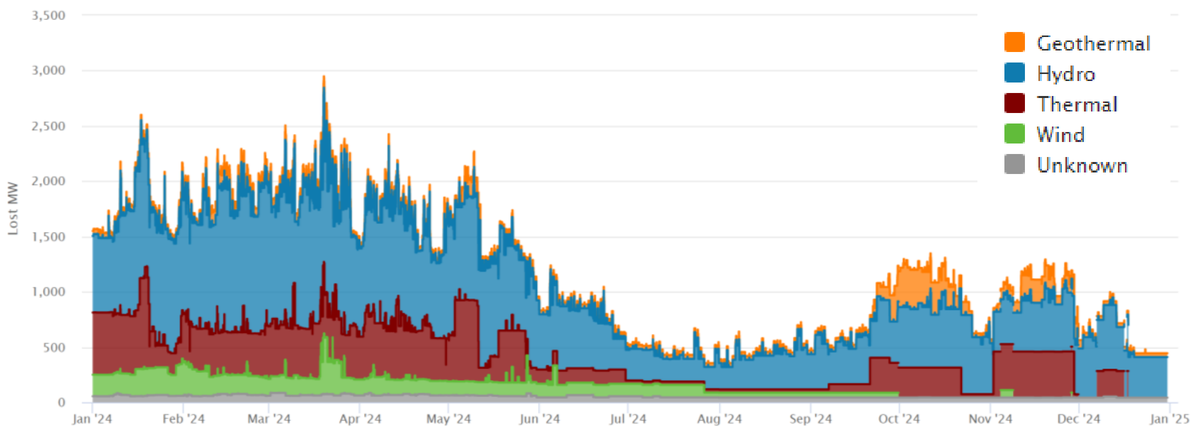
1. We have previously highlighted the need for market information and coordination to manage the transition to electrification.[60]

2. The low residual Customer Advice Notices (CANs)[61] for the morning peaks of 8 May 2024 and 10 May 2024 demonstrate the importance of flexible resources and the importance of operational coordination over the new few years. Recent events as well as the low residual CANs issued for 11 October 2023, 2 November 2023 and 3 November 2023 demonstrate that operational coordination issues are not confined to winter but can happen at other times of the year.

3. An unseasonal cold snap, low wind generation and a large number of generators on planned outage contributed to the recent low residual situations in early May. It is important to note that all available generation was offered into the market, this was not a unit commitment issue.[62] A contributing factor was not a sudden drop in wind, but a slow and large drop in wind that was forecast around 24 hours ahead of the situation.

4. Figure 4 shows that there was around 2,000MW of generation on planned outage for the week beginning 6 May 2024.

Figure 4: Scheduled generation outages for 2024 as at 6 May 2024



5. The low residual CAN for the morning peak of 10 May 2024 was issued at 7.28am on 9 May 2024. This was followed by a Warning Notice (WRN) at 10.51am to advise that there were insufficient generation offers to meet national demand and reserve requirements for the 10 May morning peak.

---

[60] Electricity Authority, *Driving efficient solutions to promote consumer interests through winter 2023.* March 2023, 9. https://www.ea.govt.nz/documents/2102/Driving-efficient-solutions-to-promote-consumer-interests-through-winter-2023-_D28umrs.pdf

[61] Transpower, *Customer Advice Notices (CAN)*. https://www.transpower.co.nz/system-operator/notices-and-reporting/customer-advice-notices-can

[62] Unit commitment problem refers to the extended start times for some thermal plant, and the decision that plant operators need to make to ensure plant costs can be recovered. When intermittent and hydro generation is high, this can reduce the immediate commercial incentives to warm up slow-start thermal plant on the chance that wind may unexpectedly fall away.

6. Early notice of the situation from the system operator allowed industry participants to work together to use all possible levers to increase generation or decrease demand. The initiatives implemented by the Authority for winter 2023[63] also provided industry with additional information to closely monitor the situation. Generators recalled units from outage earlier than planned, large industrial users and domestic users reduced consumption and distributors reduced controllable load. The system operator estimates demand reduction of around 240MW for the 7.30am trading period.[64] SolarZero reported that they provided up to 30MW of injection on the morning of 10 May. The NewPower BESS was offered into the market providing both energy injection and instantaneous reserve. Although the situation was tight, forced demand shedding was avoided due to industry and consumer actions.

7. While the end outcome was positive, the events highlight the need for additional coordination, particularly outage coordination. While it is positive to see generators taking maintenance outages ahead of winter, the system operator had issued a New Zealand Generation Balance (NZGB) CAN to advise of potential shortfalls following the loss of the two largest sources of supply (N-1-G) for 9 May and 10 May.[65] There were indications that the system was tight, and this situation could have been better coordinated.

8. It was clear that demand-flexibility played an important role in managing the event. However, following the event, commentators have noted that consumers were not compensated for their actions. Concerns have also been raised around 'free' mass market demand response dampening wholesale prices and weakening incentives to invest in peaking, last resort generation and dispatchable demand response.

9. We share these concerns, and we are continually reviewing the market settings for demand response as part of our work programme.

10. While our recent Code amendment to clarify the availability of controllable load was a useful tool for managing these recent events, we recognise that further improvements could be made. Difference bids to signal available controllable load are not included in the dispatch schedule, so the impact of any load control from distributors (following a request from the system operator) are not accurately reflected in the final price.

11. We are exploring further enhancements to ensure that accurate price signals are maintained following a request or instruction to distributors to control load. This could include requiring distributors to submit their available controllable load in the form of a dispatchable demand bid or a dispatch notification bid so that their load control is used to determine the final price.

12. Ultimately, we want to see this controllable load shift from distributors to retailers so that retailers can price this demand response into the market and directly reward

[63] Electricity Authority, *Managing peak electricity demand*. https://www.ea.govt.nz/projects/all/managing-peak-electricity-demand/

[64] Transpower, *Weekly Market Movements - Week Ended 12 May 2024.* 2024. https://static.transpower.co.nz/public/bulk-upload/documents/Market%20Operations%20-%20Weekly%20Market%20Movements%20-%2012%20May%202024.pdf

[65] Transpower, *NZGB Assessment for Potential Negative Generation Balances in May 2024*. May 2024, 1). https://static.transpower.co.nz/public/interfaces/can/CAN%20NZGB%20Assessment%20for%20Potential%20Negative%20Generation%205360226464.pdf?VersionId=yMcH_LoVQDhuQXyUEzqIzqdsD26eOvDZ

consumers for their efforts. We support the continued development of retail offerings to incentivise and reward consumers for shifting demand away from peak periods.

13. These recent events have also highlighted the need to enhance outage coordination by clarifying roles and responsibilities for providing asset outage information and assessing the potential impact on security of supply.

14. We intend to start a project to investigate potential improvements to the outage coordination process. Improvements may include:

    a) making the planned outage coordination process (POCP) mandatory

    b) obligations on assets owners to provide and update outage data during certain time horizons

    c) obligations on asset owner to provide additional information such as recall time for outages

    d) strengthening the system operator’s obligations and actions around outage planning.

15. This work is planned to start in July 2024 and will be followed by consultation once any proposed improvements are sufficiently developed.

Appendix C System operator study (TASC 55): MFK Refinement

TASC 55 – Normal Frequency Management Strategy Project

MFK Refinement

TRANSPOWER

IMPORTANT

NOTICE

This document contains advice to the Electricity Authority provided by the System Operator under the Technical Advisory Service Contract between the parties. This advice does not constitute a System Operator or Transpower proposal, and must not be represented as such by the Electricity Authority

LIMITATION OF LIABILITY/DISCLAIMER OF WARRANTY

Transpower make no representation or warranties with respect to the accuracy or completeness of the information contained in the report. Unless it is not lawfully permitted to do so, Transpower specifically disclaims any implied warranties of merchantability or fitness for any particular purpose and shall in no event be liable for, any loss of profit or any other commercial damage, including but not limited to special, incidental, consequential or other damages.

Contact Details

Address:	Transpower New Zealand Ltd 96 The Terrace PO Box 1021 Wellington New Zealand
Telephone:	+64 4 495 7000
Fax:	+64 4 498 2671
Email:	system.operator@transpower.co.nz
Website:	https://www.transpower.co.nz

Contents

1. EXECUTIVE SUMMARY

TASC 55 multiple frequency keeping (MFK) refinement was commissioned by the Electricity Authority (EA) to study the effects of refining the system operator's frequency keeping bands. The work followed implementation of improvements to the system operator's security assessment and management tools (SO security tools), itself following introduction of HVDC capability and control changes in 2014.

The work required completing 16 tests focused on:

1. Pre-Solve Deviation (PSD) functionality and optimising PSD settings.
2. Use of augmented (automatic PSD calculation, automatic dispatch send) dispatch with frequency keeping control (FKC) operation.
3. The effect of reducing the MFK bands, covering:
    a. 30 MW of MFK: 20 MW North Island, 10 MW South Island, FKC enabled.
    b. 20 MW of MFK: 10 MW North Island, 10 MW South Island, FKC enabled.
    c. 0 MW of MFK: FKC enabled.
    d. 25 MW of North Island MFK, 25 MW of South Island MFK, FKC disabled.

Observations were made for effects of operating with different MFK bands on time error, HVDC modulation, frequency and extent to which governors were off dispatch. Results were as follows:

1. Time Error

    Time error can be effectively managed to well within the code requirement of ±5 seconds under all test periods. MFK has a positive effect on time error control; however, with the right PSD settings time error can be effectively managed using only dispatch.

2. HVDC modulation

    Results indicate a relationship between the MFK MW band and the amount the FKC modulates the HVDC. With a higher MFK regulation band, less HVDC modulation is seen.

3. Frequency

    Comparing 30 MW MFK band to 20 MW MFK band operations, the data indicated no deterioration in frequency. Comparing 30 MW MFK band to 0 MW MFK band, the data showed an increase in standard deviation of frequency in the North Island. In all tests with FKC enabled the frequency variation was better than what had been the normal North Island frequency variation.

4. Governors off dispatch

    Considering governor off dispatch, a comparison of 30 MW and 20 MW MFK operations data showed a slight increase in governor action. Comparing 30 MW and 0 MW of MFK, a larger increase in governor action was seen.

Recommendations

1. Utilise future FKC outages for trial operation with North Island 25 MW MFK.
2. Consider further PSD enhancement.

3. If reducing the MFK bands with FKC enabled is considered for introduction in to operations, the benefits of reducing MFK should first be assessed against the impact it will have on governors off dispatch and HVDC modulation.

This report is intended for readers with a reasonable understanding of power system operation (particularly in dispatch and the frequency keeping ancillary service) and knowledge of Transpower's earlier reports on FKC and MFK operations[1].

[1] FKC Trial Report *https://www.systemoperator.co.nz/sites/default/files/bulk-upload/documents/FKC%20Trial%20Report.pdf*

FKC Technical Report *https://www.systemoperator.co.nz/sites/default/files/bulk-upload/documents/FKC%20Technical%20Report.pdf*

2. INTRODUCTION AND BACKGROUND

2.1 INTRODUCTION

2.1.1 FREQUENCY KEEPING CONTROL AND MULTIPLE FREQUENCY KEEPING

On 16th October 2014, a 6 month trial of frequency keeping control (FKC) operation was undertaken. FKC modulates the active power on the HVDC to tie the North and South Island frequencies together.

FKC was found to be beneficial to economic operation of the power system, notably by reducing the amount of frequency keeping required and hence the cost of the frequency keeping ancillary service.

Before FKC operations were introduced, frequency keeping was transitioned from a system of single frequency keeping (SFK), where one generator in each island was contracted to provide the total frequency keeping MW range, to a system of multiple frequency keeping (MFK), where multiple generators would each take a portion of the total MW. Frequency keeping behaviour with SFK was dependant on the individual frequency keeping generator, as SFK was reliant on a generator's control system. Frequency keeping behaviour with MFK is dependent on a centralised control system, which measures frequency and sends continuous frequency keeping regulation instructions to MFK participants.

When FKC was enabled it was found that significantly fewer MWs were required by MFK to fulfil the frequency keeping function. Frequency keeping bands were changed from 50 MW in the North Island and 25 MW in the South Island to 20 MW in the North Island and 10 MW in the South Island.

2.1.2 SO SECURITY TOOLS UPGRADE PROJECT

In September 2015, an upgrade to the SO security tools took place. This increased the capability of the market system tools and simplified operational procedures to maintain security while FKC and Roundpower[2] are active.

The upgrade enhanced the capability of the Pre-Solve Deviation calculation tool (PSD, see Section 2.2) to enable it to run in automatic mode whilst FKC is in operation. This capability required tuning and testing to gain operational confidence.

2.1.3 MFK REFINEMENT AND PSD TESTING

Since introduction of FKC, power system operation is being continuously optimised to adapt to this new technology. Frequency keeping has been reduced from 75 MW to 30 MW. But, could the power system be operated with even less frequency keeping service?

From October 2015 to February 2016 a series of power system tests were conducted with three purposes in mind:

---

[2] An operational mode of the HVDC which allows seamless switching between north and south transfer.

1. To optimise PSD settings to give both a stable dispatch and reduce HVDC modulations and time error fluctuations.
2. To test automatic dispatch[3] with FKC operation.
3. To test operation with 30 MW of MFK, 20 MW of MFK, and 0 MW of MFK and to study power system operation under each scenario.

2.1.4 TASC 55 – MFK REFINEMENT

As part of the Normal Frequency Management Strategy Project, Transpower was tasked by the EA with TASC 55 – MFK Refinement, to optomise the quantity of MFK purchased.

This report presents analysis of the MFK band and PSD tests, with a focus on the operational effects of using the different MFK MW bands.

2.2 PSD INPUTS

A significant part of the testing focused on the variations to the PSD inputs.

Figure 1 shows the PSD interface into the Market Operator Interface (MOI)[4]. The inputs to the PSD calculation which were important to the testing periods analysed in this report were:

- Time error: the time errors for both North and South Islands were input into the calculation. Where time error exceeded the deadband in either direction, the corresponding time error correction would offset by a fixed quantity the dispatch to the island where time error had exceeded the deadband
- DC sent: the difference between the HVDC MW transfer and the HVDC dispatch was applied to offset each island’s dispatch
- MFK Average Regulation Value: the average MFK regulation value in each island for the previous 5 minute dispatch periods was applied to each island dispatch.

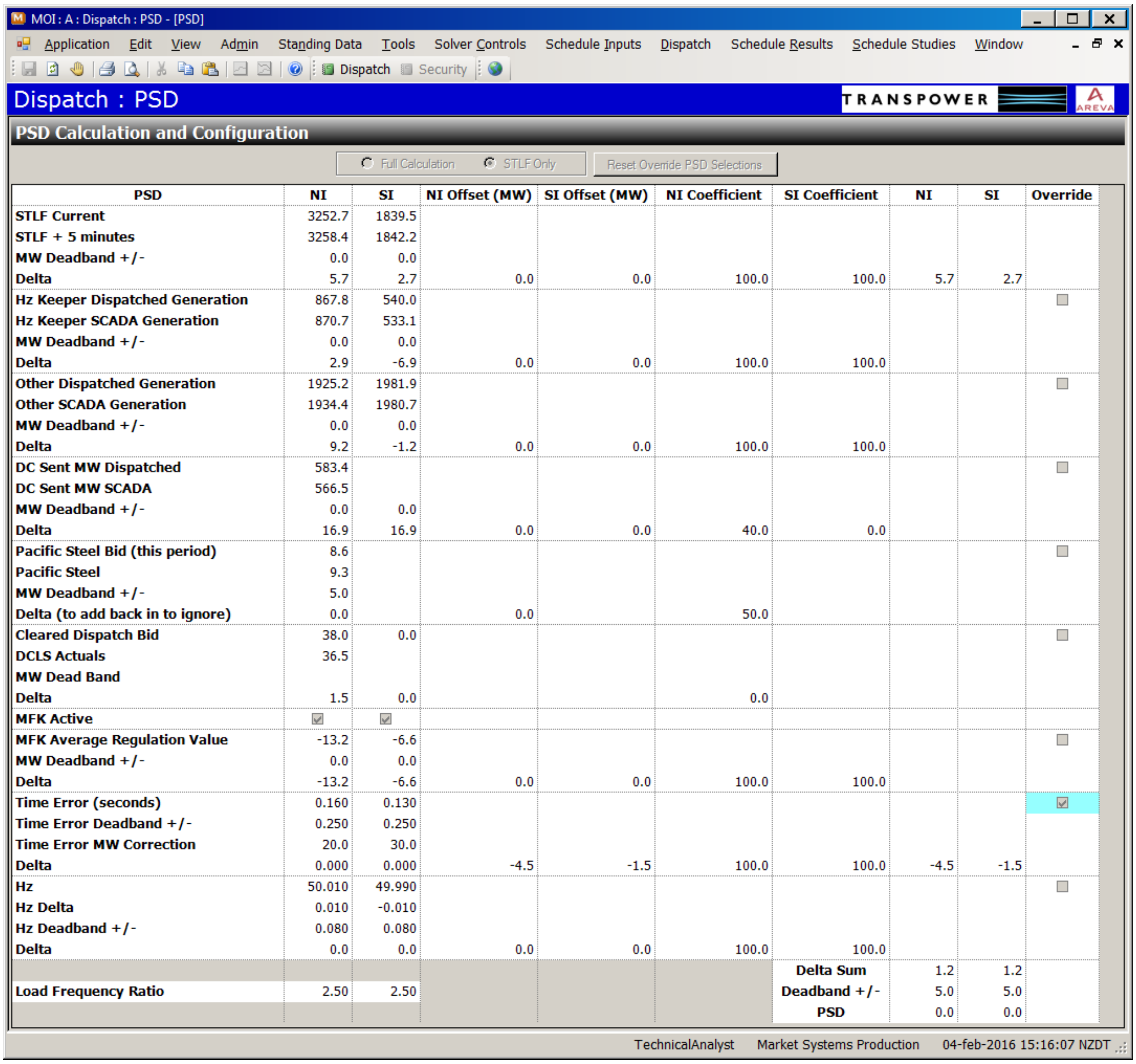
All inputs into the PSD could have, as options, the addition of a constant offset in each island or adjustment to the coefficient for each island.

The constant offset would offset the dispatch at all times, regardless of the PSD input.

The coefficient for each island would affect the participation of the input into each island dispatch. For example, if the South Island coefficient was set to 0 for the HVDC sent input, only the North Island dispatch would be affected by HVDC being off dispatch.

[3] Automatic dispatch refers to the action of sending a dispatch solution. It does not refer to the whole dispatch process which, amongst other things, requires creation and security checking of dispatch schedules. In the dispatch context, the term augmented dispatch refers to the dispatch process in which some, but not all, elements of the process are automated.

[4] System co-ordinators access their operational tools using the MOI.



PSD	NI	SI	NI Offset (MW)	SI Offset (MW)	NI Coefficient	SI Coefficient	NI	SI	Override
STLF Current	3252.7	1839.5							
STLF + 5 minutes	3258.4	1842.2							
MW Deadband +/-	0.0	0.0							
Delta	5.7	2.7	0.0	0.0	100.0	100.0	5.7	2.7	
Hz Keeper Dispatched Generation	867.8	540.0							☐
Hz Keeper SCADA Generation	870.7	533.1							
MW Deadband +/-	0.0	0.0							
Delta	2.9	-6.9	0.0	0.0	100.0	100.0			
Other Dispatched Generation	1925.2	1981.9							☐
Other SCADA Generation	1934.4	1980.7							
MW Deadband +/-	0.0	0.0							
Delta	9.2	-1.2	0.0	0.0	100.0	100.0			
DC Sent MW Dispatched	583.4								☐
DC Sent MW SCADA	566.5								
MW Deadband +/-	0.0	0.0							
Delta	16.9	16.9	0.0	0.0	40.0	0.0			
Pacific Steel Bid (this period)	8.6								☐
Pacific Steel	9.3								
MW Deadband +/-	5.0								
Delta (to add back in to ignore)	0.0		0.0		50.0				
Cleared Dispatch Bid	38.0	0.0							☐
DCLS Actuals	36.5								
MW Dead Band									
Delta	1.5	0.0			0.0				
MFK Active	☑	☑							
MFK Average Regulation Value	-13.2	-6.6							☐
MW Deadband +/-	0.0	0.0							
Delta	-13.2	-6.6	0.0	0.0	100.0	100.0			
Time Error (seconds)	0.160	0.130							☑
Time Error Deadband +/-	0.250	0.250							
Time Error MW Correction	20.0	30.0							
Delta	0.000	0.000	-4.5	-1.5	100.0	100.0	-4.5	-1.5	
Hz	50.010	49.990							☐
Hz Delta	0.010	-0.010							
Hz Deadband +/-	0.080	0.080							
Delta	0.0	0.0	0.0	0.0	100.0	100.0			
						Delta Sum	1.2	1.2	
Load Frequency Ratio	2.50	2.50				Deadband +/-	5.0	5.0	
						PSD	0.0	0.0	

Figure 1 PSD interface in the MOI

2.3 DISPATCH MODES

During these tests, three dispatch modes were used in the PSD tool:

1. Manual/Manual: The PSD applied to the dispatch is a manual input from the system co-ordinator and the dispatch instruction is sent manually. No tests were run exclusively in this mode. However, at times dispatch was switched to this mode if co-ordinators chose, to manage situations such as load ramps manually or for training purposes.
2. Manual/Auto: The PSD applied to the dispatch is an automatic calculation and the dispatch instruction is sent manually. The first tests were carried out in this mode.
3. Auto/Auto (Augmented): The PSD applied to the dispatch is an automatic calculation and the dispatch instruction is sent automatically. The tool has safety thresholds which if exceeded will not send a dispatch instruction automatically. After initial tests to tune PSD input settings, remaining tests were carried out in this mode. This is augmented dispatch mode.

3. TEST PERIODS

The work involved a series of weekly test periods testing different aspects of using PSD inputs, different MFK bands, and manual or augmented dispatch. The testing periods are in Table 1.

Table 1 Test periods

Test Period	Start Time	End Time	FKC	MFK		PSD Inputs
				NI	SI	
Test period 1	21/10/2015 12:00	28/10/2015 12:00	On	20	10	Time error
Test period 2	28/10/2015 12:00	4/11/2015 12:00	On	20	10	Time error DC sent
Test period 3	4/11/2015 12:00	11/11/2015 12:00	On	20	10	Time error MFK
Test period 4	11/11/2015 12:00	18/11/2015 12:00	On	20	10	Time error DC sent
Test period 5	18/11/2015 12:00	25/11/2015 12:00	On	20	10	Time error Augmented dispatch
Test period 6	26/11/2015 6:30	29/11/2015 20:30	Off	25	25	FKC off
Test period 7	2/12/2015 12:00	9/12/2015 12:00	On	20	10	Time error Augmented dispatch
Test period 8	9/12/2015 12:00	16/12/2015 12:00	On	0	0	Time error Augmented dispatch
Test period 9	13/01/2016 12:00	20/01/2016 12:00	On	20	10	Time error Augmented dispatch
Test period 10	20/01/2016 12:00	27/01/2016 12:00	On	0	0	Time error Augmented dispatch
Test period 11	27/01/2016 12:00	3/02/2016 12:00	On	10	10	Time error Augmented dispatch
Test period 12	3/02/2016 12:00	10/02/2016 12:00	On	20	10	Time error Augmented dispatch
Test period 13	10/02/2016 12:00	17/02/2016 12:00	On	0	0	Time error Augmented dispatch

Test periods 1 – 4 focused on testing time error, MFK regulation and DC sent PSD inputs. These tests were carried out with automatic PSD calculation, manual send.

From test period 5 onwards, augmented dispatch was tested, along with further testing and refining of PSD settings. Based on what was seen in test periods 1 – 4, only the Time Error PSD input was used throughout the remaining tests.

Test period 6 was carried out over a period where FKC was unavailable. Since removing FKC has a market impact this testing period was bound by outage circumstances and was only carried out for approximately two and a half days.

Test periods 8, 10 and 13 tested operation with 0 MW of MFK, relying only on governor action and dispatch to maintain frequency.

Test period 11 tested operation with 20 MW of MFK.

To compare time error, MFK regulation and HVDC modulation behavior before the testing with the upgraded SO tools started, data from July 2015 was used.

Following the first set of test periods, 3 additional test periods were undertaken in May to further study reduced MFK operation. These are given below in Table 2.

Table 2 Additional test carried out in May

Test Period	Start Time	End Time	FKC	MFK		PSD Inputs
				NI	SI	
Test period 14	11/05/2016 12:00	18/05/2016 12:00	On	15	15	Time Error
Test period 15	18/05/2016 12:00	25/05/2016 12:00	On	0	0	Time Error
Test period 16	25/05/2016 12:00	1/06/2016 12:00	On	10	10	Time Error

4. STUDY METHODOLOGY

This section outlines the study methodology undertaken in this analysis.

For all measures, statistical data was calculated from Plant Information (PI) data over full test periods.

4.1 TIME ERROR

Time error data was analysed using data with 1 minute resolution.

The measures looked at were:

1. Average time error (seconds).
2. Absolute average time error (seconds).
3. Time per day spent above 0.3 seconds (minutes/day) – absolute value.
4. Time per day spend above 0.5 seconds (minutes/day) – absolute value.

With FKC enabled the two island time errors move together, with a relatively constant gradient of divergence across extended time periods. With this behavior, the variation of North and South Island time error could be analysed together, rather than separately. For all test periods where FKC was enabled, analysis was undertaken on the average of North and South Island time errors.

4.2 MFK REGULATION

MFK regulation data was analysed using data with 1 minute resolution.

The total MFK regulation was calculated from a sum of regulation to all MFK active participants. This did not capture actual MFK participant generation output changes, so any variation in performance which may have been caused due to different MFK participants will not have been captured in this analysis. With the data available, analysing the MFK participant generation output changes from the MFK regulation signal was impractical.

The measures looked at for MFK regulation were:

1. Average MFK regulation (MW).
2. Absolute average MFK regulation (MW).
3. Time per day spent above 66% – absolute value:
4. Time per day spend above 93% – absolute value:
5. Cumulative distribution function with the 5^{th}, 50^{th} and 95^{th} percentiles highlighted.

During the period when FKC was disabled, MFK was operated with 25 MW of MFK in each island. In the North Island this period was split between 25 MW regulation band and 30 MW regulation band. This is in Figure 2 below.

The MFK market tool finds the cheapest option to cover at least 25 MW as it was the North Island MW band setting for the test period. Depending on offers from MFK participants, the cheapest combination could exceed 25 MW. During the test period it was found that significant time was spent with 30 MW of MFK in the North Island.

Filtering the periods with 30 MW of MFK in the North Island was considered, but resulted in a loss of too much data.

Analysis was performed on the full period including periods with 25 MW North Island MFK regulation and 30 MW North Island MFK regulation. While including the periods where 30 MW MFK was procured will have had an effect on the analysis, especially when calculating time spent at the limits, it is representative of the expected behaviour with 25 MW of MFK set to be procured in the North Island.

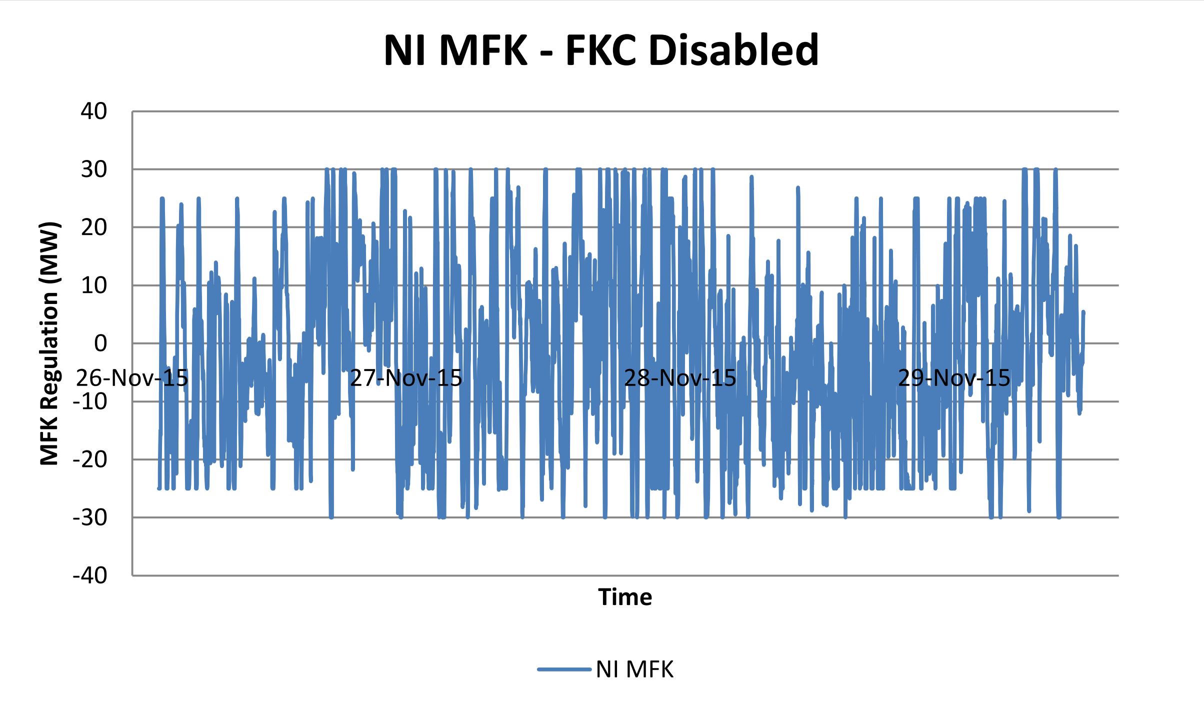


Figure 2 NI MFK with FKC disabled – test period 6

4.3 HVDC MODULATION

HVDC modulation was analysed using data with 1 minute resolution.

Data available for this analysis was:

- HVDC MW dispatch
- HVDC bipole MW transfer
- FKC modulation
- HVDC ramping status.

During periods with FKC enabled, the PI tag used for analysis was the signal for FKC modulation. This has advantages over using the HVDC dispatch and HVDC bipole transfer as the data does not need to be filtered for the HVDC ramping to meet dispatch changes.

During periods with FKC disabled, HVDC modulation was calculated using HVDC dispatch, and HVDC bipole transfer PI tags. Periods where the HVDC was ramping to meet dispatch changes were filtered out with the HVDC ramping status PI tag, which signals when the HVDC is ramping.

The measures looked at for HVDC modulation were:

1. Average HVDC modulation (MW).
2. Absolute average HVDC modulation (MW).
3. Time per day spent above 20 MW (minutes/day) – absolute value.
4. Time per day spend above 30 MW (minutes/day) – absolute value.
5. Cumulative distribution function with the 5th, 50th and 95th percentiles highlighted. This was done only for periods with FKC enabled.

HVDC dispatch data was also used to derive an indicative measure of the quantity of dispatches sent. While not all dispatches involved the HVDC, being one of the more consistently dispatched assets on the power system the HVDC dispatches could provide an indication for this analysis.

4.4 FREQUENCY

Frequency was analysed using data with 2 second resolution.

The measures used for analysis of frequency were chosen to line up with the analysis of frequency in TASC 49 Phase 1: Performance Benchmarks. This allowed easy comparison between the analysis presented here and the benchmarks provided in TASC 49.

The measures looked at for frequency variation were:

1. Mean average.
2. Standard deviation.
3. From 1 and 2: Average ± 3*Standard Deviation – this gave the upper and lower bound of values between 0.3% and 99.7%.

Transpower's TASC 49 report to the Authority provided North Island and South Island benchmarks[5] for:

1. SFK benchmark.
2. 30 MW of MFK with FKC Enabled: NI 20 MW, SI 10 MW.

[5] TASC 49 Phase 1:Performance Benchmarks, page 5

3. Governor response only: MFK 0 MW.

In addition to the TASC 49 benchmarks, the period from 15th November 2014 – 15th December 2014 was analysed to give a representation of MFK operation with FKC disabled – 50 MW North Island MFK band, 25 MW South Island MFK band. Due to the length of time over which results were analysed, the data for this period was sampled at 15 seconds, rather than 2 seconds for the other periods. This will not have significantly affected the results.

4.5 GOVERNOR OFF DISPATCH

The governor off dispatch analysis studied two of the MFK generation blocks recognised as having governors responsive to frequency deviations in the normal band.

There is no data available in PI which directly provides governor regulation signal from these generators. Therefore, calculation from other data was needed.

Data available for this analysis was:

- block dispatch values for total generation groups – this was a single station or a combination of stations
- actual active power output of individual generator units
- generator circuit breaker status
- generation block MFK regulation band.

The governor off dispatch analysis was carried out by calculating the difference between the generation block dispatch and the sum of all individual active power outputs. Analysis was undertaken using 10 second resolution data on two generation groups in the South Island.

As these generation blocks are MFK participants, the times these generation groups were actively participating in MFK would produce large governor off dispatch values. Therefore, data for those times was filtered out in the analysis.

Active power output was converted to per unit by calculating the overall MW rating based on which unit circuit breakers were currently closed.

A challenge with this analysis was filtering out the times taken to ramp to new dispatch set points. This was managed by ignoring values immediately following and preceding large dispatch changes – a larger dispatch change resulted in more data being filtered out. Ignoring values before a dispatch change accounts for the dispatch and MW output data not being completely time synchronised.

5. RESULTS AND DISCUSSION

The test periods described in Table 1 (Section 3) are grouped into the following categories defined below in Table 3.

Table 3 Test period categories used in results analysis

Category	North Island MFK	South Island MFK	Test Periods
30 MW MFK band	20 MW	10 MW	1, 2, 3, 4, 5, 7, 9, 12, 14
20 MW MFK band	10 MW	10 MW	11, 16
0 MW MFK band	0 MW	0 MW	8, 10, 13, 15
25/25 MW MFK band – FKC Disabled	25 MW	25 MW	6

5.1 TIME ERROR

Control of time error during the tests was mainly influenced by:

1. The time error PSD input settings; and
2. MFK regulation.

Time error input had a range of settings ranging from a 0.15 second deadband, 15 MW correction in each island to 0.25 second deadband and 20 MW North Island, 30 MW South Island. A permanent negative offset to the PSD was also trialed through the time error PSD input.

To compare time error behavior before the testing with the upgraded tools started, data from July 2015 was analysed for time error variation.

To compare the effect of MFK on time error control the comparison of test periods with similar PSD settings was made. Consequently, along with the total results, individual test periods with similar PSD settings were compared:

- Test Period 9 – 30 MW MFK, 0.15 second deadband, 25 MW North Island correction, 35 MW South Island correction.
- Test Period 11 – 20 MW MFK, 0.15 second deadband, 15 MW North Island correction, 25 MW South Island correction
- Test Period 10 – 0 MW MFK, 0.15 second deadband, various North and South Island MW correction.

Note: with the exception of Test Period 6 (FKC disabled), the time error was analysed as an average of North and South Island time errors.

Figure 3 shows the time error average and absolute average; Figure 4 shows the minutes / day the time error spent above 0.3 and 0.5 seconds. A table of results for all test periods is in Appendix A: Full Overall Comparison Tables.

From the average and time-above thresholds analysis the following is noted:

- Time error absolute average and time above 0.3 and 0.5 seconds / day data shows a significant improvement throughout the SO Tools testing from pre SO tools operation

- Test period 11, with 20 MW of MFK, shows a better result than with 30 MW of MFK. This is likely due to the variation seen within the 30 MW MFK results as the PSD settings were refined. Comparing test period 11 with test period 9 shows that very similar time error control has been seen with 20 MW and 30 MW of MFK
- The data indicates that with 0 MW of MFK time error control is impacted. However with the right settings in the time error PSD input good control of time error can be achieved. Test period 10, with 0 MW of MFK has an absolute average only slightly worse than test periods 9 and 11
- The Electricity Industry Participation Code (EIPC) obligations for managing time error are to keep time error within ±5 seconds. These tests have shown the PSD can be used to keep time error much tighter than that if required

The PSD settings for 0 MW of MFK were continually optimised throughout the testing. Test period 13, the final week of 0 MW MFK, was compromised due to issues with market tools for some time. Test period 14, the additional 0 MW of MFK test period carried out in May, showed good time error control.

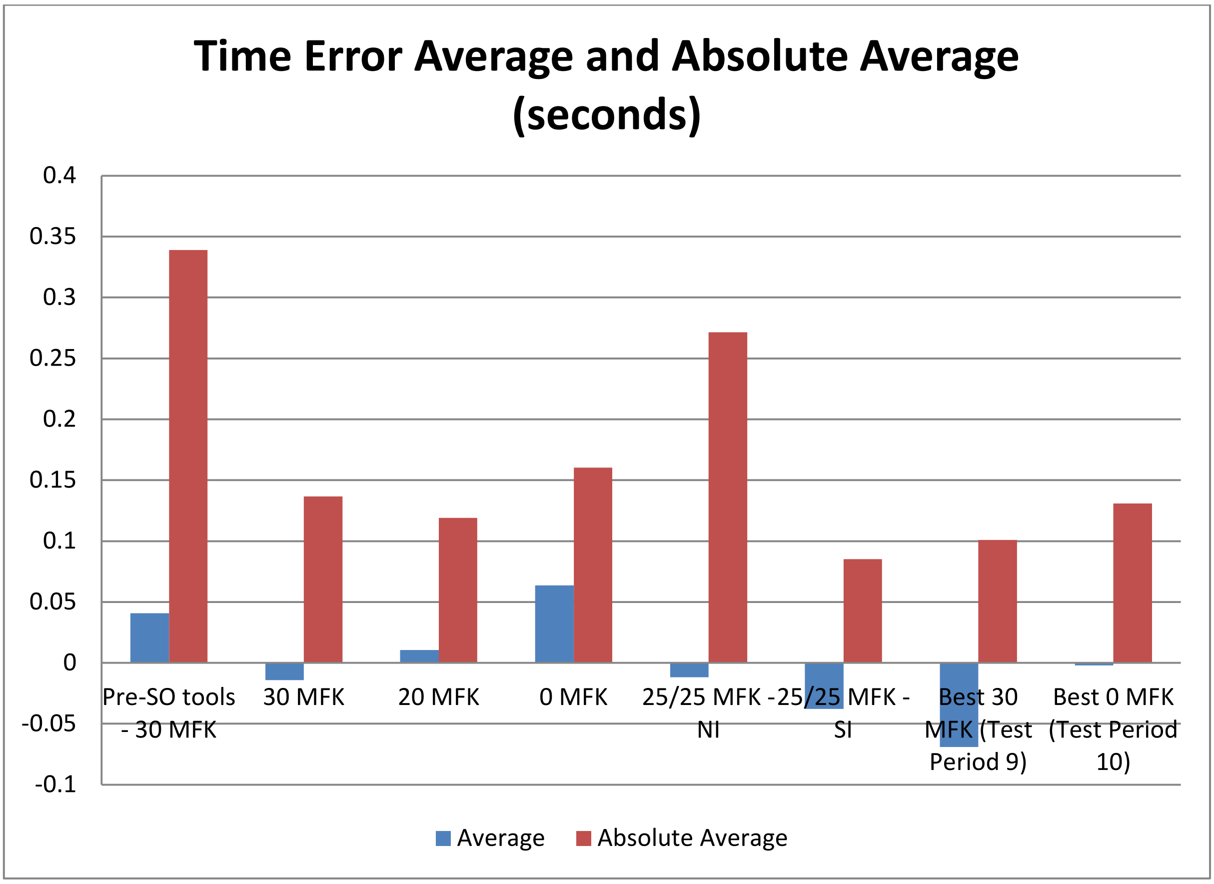


Figure 3 Time error analysis results – Average and Absolute Average

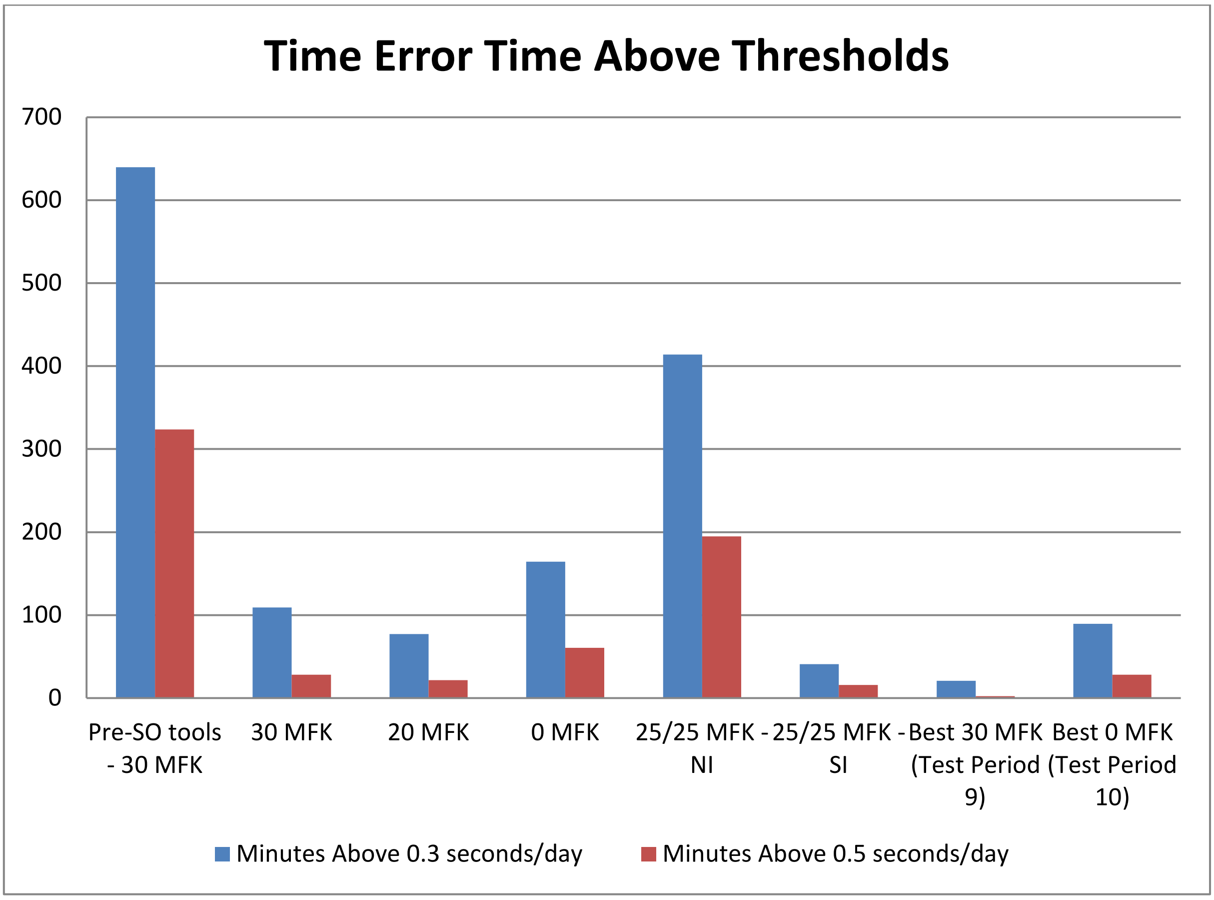


Figure 4 Time error analysis results – time above thresholds

5.1.1 FKC DISABLED

With FKC disabled South Island time error was very close to 0 seconds. North Island timer error was notably higher than during other periods in the trial but was nevertheless much lower than before SO security tools operation with FKC.

5.2 MFK REGULATION

Throughout the PSD testing (with the upgraded SO security tools) no patterns of improvement in or deterioration of MFK regulation were observed.

To compare MFK regulation behavior, before and after testing with the upgraded tools started, data from July 2015 was analysed for MFK regulation.

Figure 5 shows the average and absolute MFK regulation; Figure 6 gives the time above thresholds. As discussed in 4.2, the thresholds chosen for the analysis were 66.7% and 93%, resulting in different MW for the different MFK bands.

Full results are in Appendix A: Full Overall Comparison Tables.

From the analysis the following is noted:

- with 30 MW of MFK the data suggests there was less regulation during the test periods than in before the SO security tools upgrade

- comparing 30 MW of MFK with 20 MW of MFK the reduction in average regulation with 20 MW was sensible given that MFK is operating within a tighter band. When comparing 20 MW and 30 MW operation by % of the band, more time is spent at the higher end of the band when in 20 MW of MFK operation.
- throughout the test periods the average MFK regulation consistently had a negative average.

Additional tests in May showed very similar MFK usage to the original set of tests.

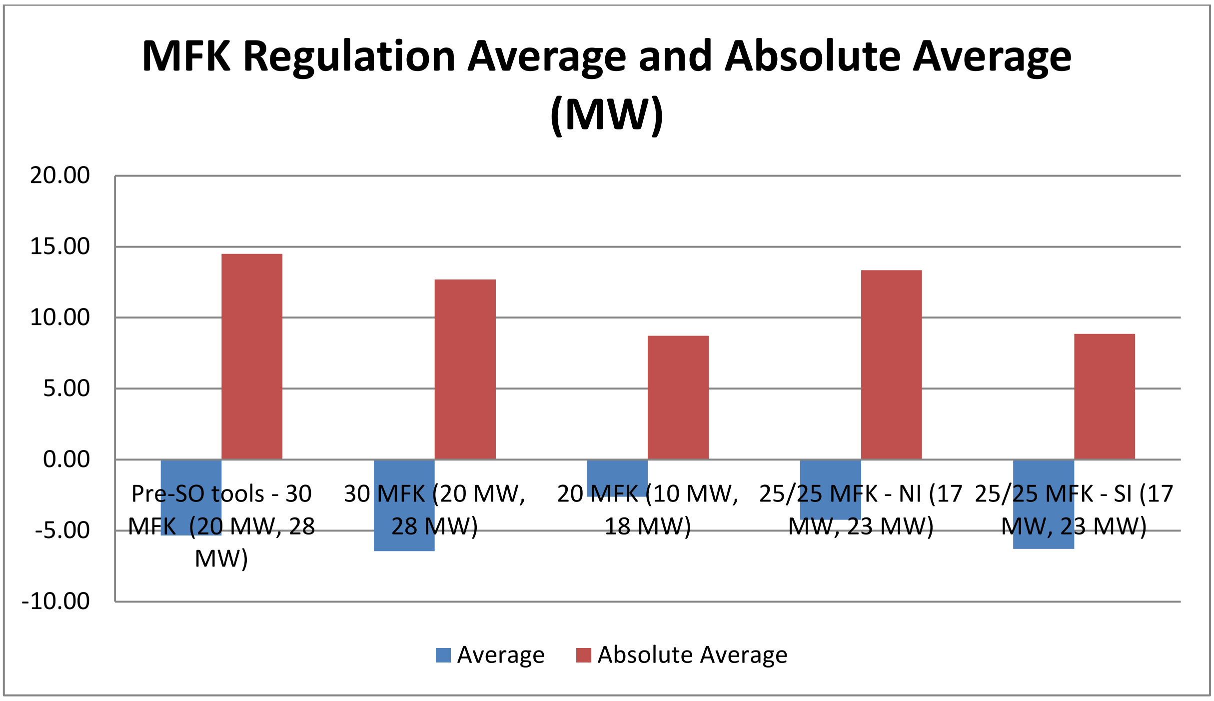


Figure 5 MFK regulation analysis results – Average and Absolute Average

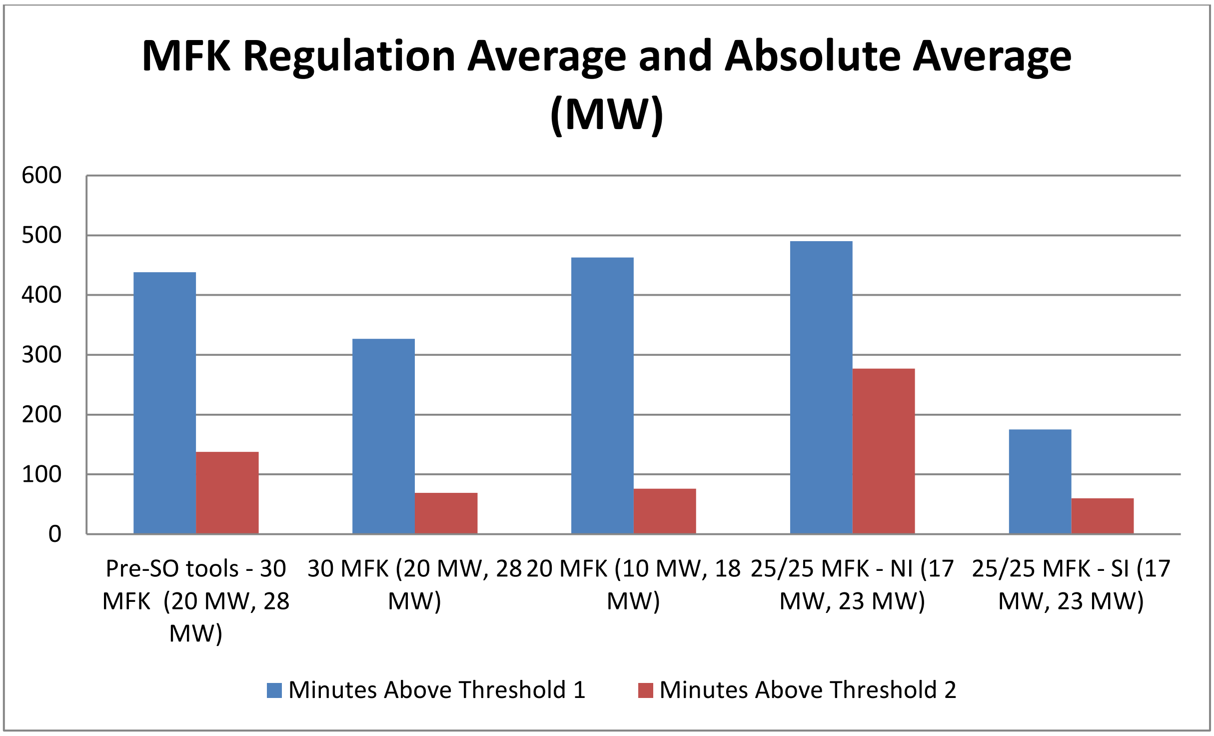


Figure 6 MFK regulation analysis results – time above thresholds 1 and 2

Figure 7 shows the cumulative distribution function for both 30 MW of MFK and 20 MW of MFK as a percentage of the MFK regulation band.

Both the 30 MW and 20 MW band data showed more activity in the negative region than in the positive region, with 5% of the time being within 1 MW of maximum negative regulation.

Table 4 MFK regulation percentile values

Frequency Keeping Configuration	5th Percentile MW / %	50th Percentile MW / %	95th Percentile MW / %	5th – 95th Percentile Range MW
30 MW MFK Band	-27.2 / -91%	-7.8 / -26%	18.9 / 63%	46.2 / 154%
20 MW MFK Band	-17.8 / -89%	-3.3 / -17%	14.8 / 74%	32.5 / 163%

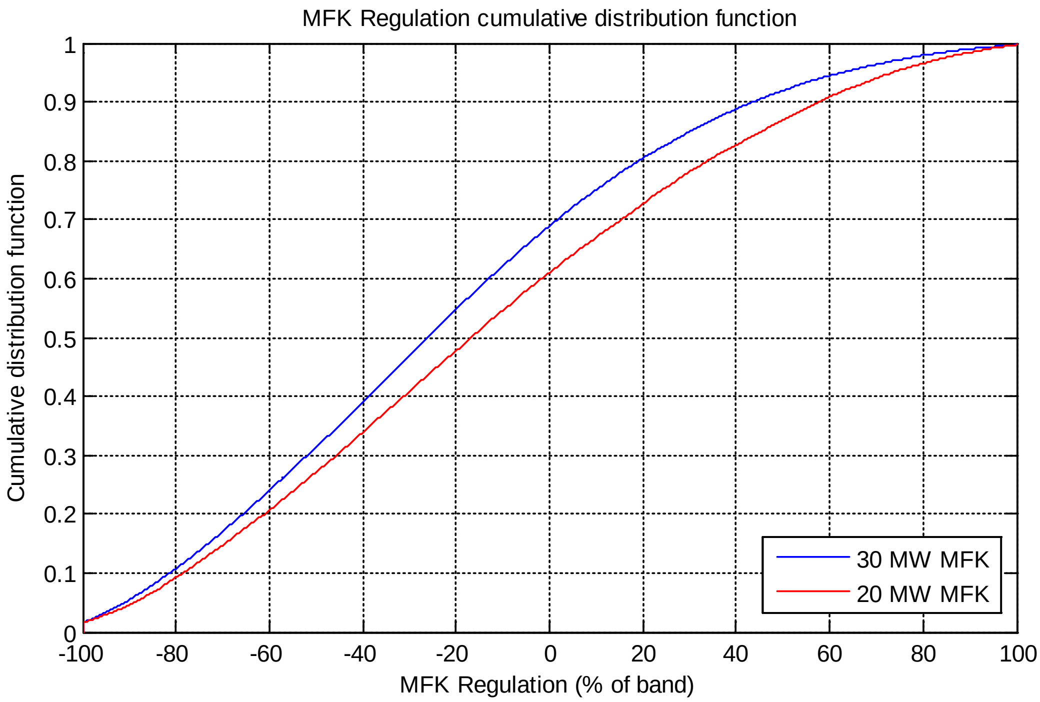


Figure 7 MFK regulation cumulative distribution function

5.2.1 FKC DISABLED

MFK operation with FKC disabled showed a much higher use of MFK in the North Island than the South Island. This is partly due to the North Island MFK band being 30 MW rather than 25 MW for about half of the review period. This is discussed further in Section 4.2.

The North Island, despite having only a 25 MW MFK band half of the time, had the same absolute average as the 30 MW MFK band data with FKC enabled. The time spent above 23.3 MW, close to the maximum of 25 MW, averaged out to about 5 times greater in the North Island than in the South Island, partly due to the North Island having 30 MW of MFK some of the time.

Figure 8 shows the cumulative distribution function for both the North and South Islands with 25 MW band. Table 5 gives percentile values for North and South Island MFK regulation.

The South Island shows more activity in the negative region, the 95th percentile being a third of the maximum 25 MW regulation limit.

The North Island is much closer to regulating evenly positive and negative.

Table 5 MFK Regulation percentile values – FKC Disabled

Frequency Keeping Configuration	5th Percentile MW / %	50th Percentile MW / %	95th Percentile MW / %	5th – 95th Percentile Range MW / %
25 MW MFK Band – North Island (FKC Disabled)	-26.8 / 107%	-1.5 / -6%	23.9 / 96%	50.7 / 202.8%
25 MW MFK Band – South Island (FKC Disabled)	-20.9 / -83%	-6.3 / -25%	8.3 / 33%	29.2 / 116.8%

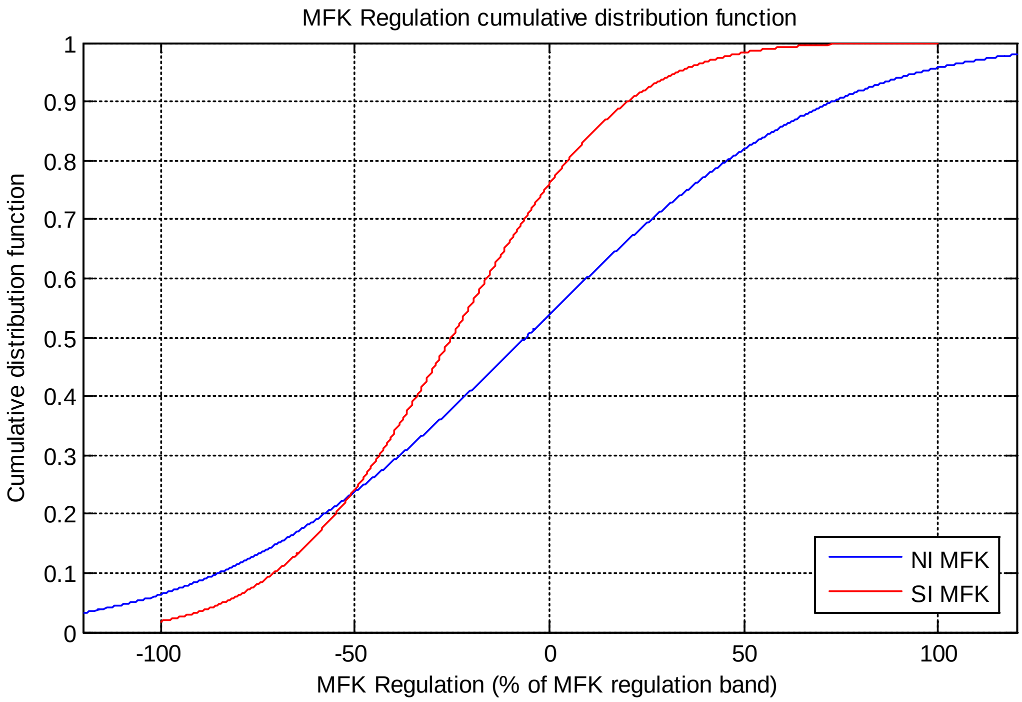


Figure 8 MFK cdf function – FKC disabled

5.3 HVDC Modulation

HVDC modulation was impacted by the PSD settings. Test periods 2 and 4 tested the use of the DC sent PSD input to improve HVDC modulation. Results for those weeks did not reveal any major improvements to the HVDC modulation not also seen in other weeks without the DC sent PSD input.

Another strategy to reduce the HVDC modulation was to offset time error correction, i.e. instead of applying 25 MW in both the North and South Island, 30 MW was applied in the South and 20 MW in the North. This put more change of MW in the island with more reactive governors, the aim being to produce less HVDC modulation of that dispatch deviation.

To compare HVDC modulation behavior before this testing with the upgraded tools started, data from July 2015 was analysed for HVDC modulation.

Figure 9 shows the average and absolute HVDC modulation; Figure 10 gives the time above thresholds. Figure 11 shows the cumulative distribution function of the HVDC modulation under periods of 30 MW MFK, 20 MW MFK, and 0 MW MFK. Table 6 shows the 5th, 50th and 95th percentile HVDC modulation values.

From the analysis the following is noted:

- With 30 MW of MFK, the data indicated a reduction in HVDC modulation seen throughout the testing compared to pre-SO security tools operation. Test period 9 showed the least HVDC modulation.
- Comparing 30 MW of MFK with both 20 MW and 0 MW MFK bands, the data indicated a slight increase in HVDC modulation with decreased MFK bands. However, both 20 MW and 0 MW values were within the range of values seen for 30 MW MFK band, the worst being test period 5, with an absolute average of 11.9 MW, and an average of 68 minutes / day spent above 30 MW.
- Test period 8 with 0 MW MFK shows an absolute average of 12.5 MW and a daily average of 293 minutes above 20 MW / day. This is significantly worse than the periods tested with 30 MW MFK, although the data for test period 8 was significantly influenced by one particularly bad day (this may suggest that MFK has a positive impact on reducing HVDC modulation). However, given the results seen in test period 10, the tests indicate that with no MFK and the right PSD settings, the HVDC modulation can be kept on par with 30 MW MFK conditions.

Additional tests in May showed more HVDC modulation than the original tests. The tests also reinforced the relationship between less MFK and increased HVDC modulation.

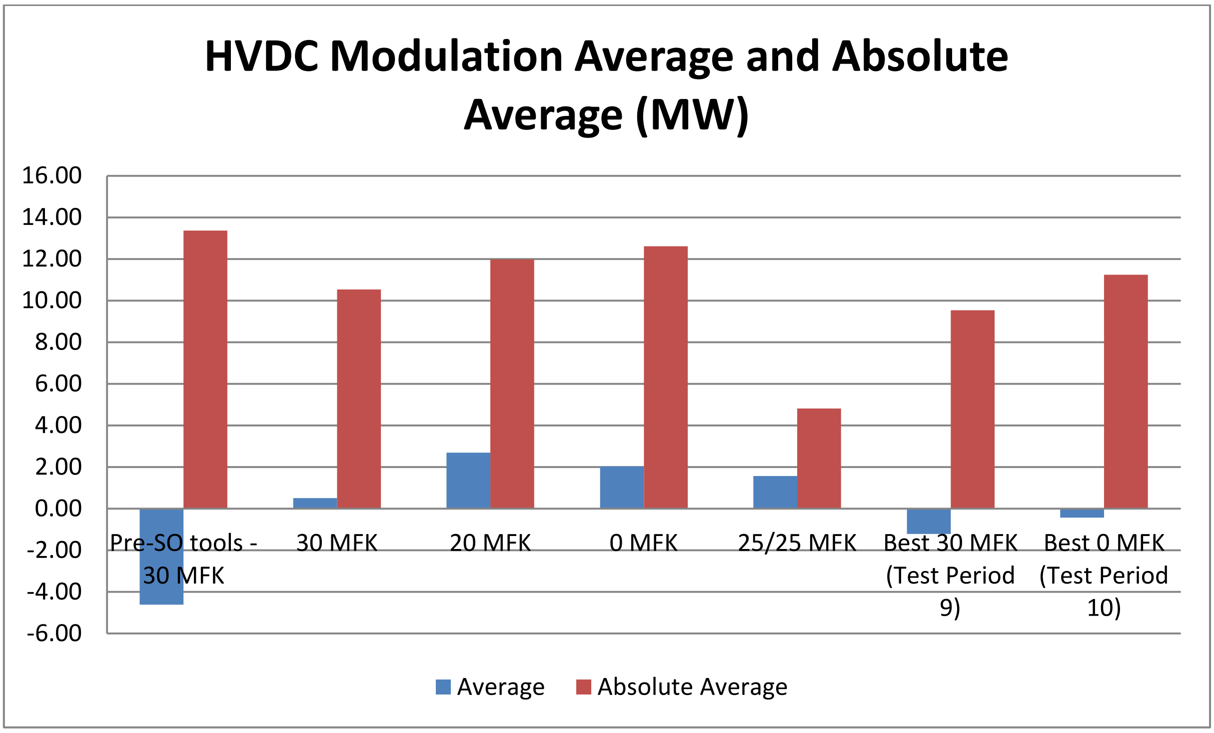


Figure 9 HVDC modulation analysis results – average and absolute average

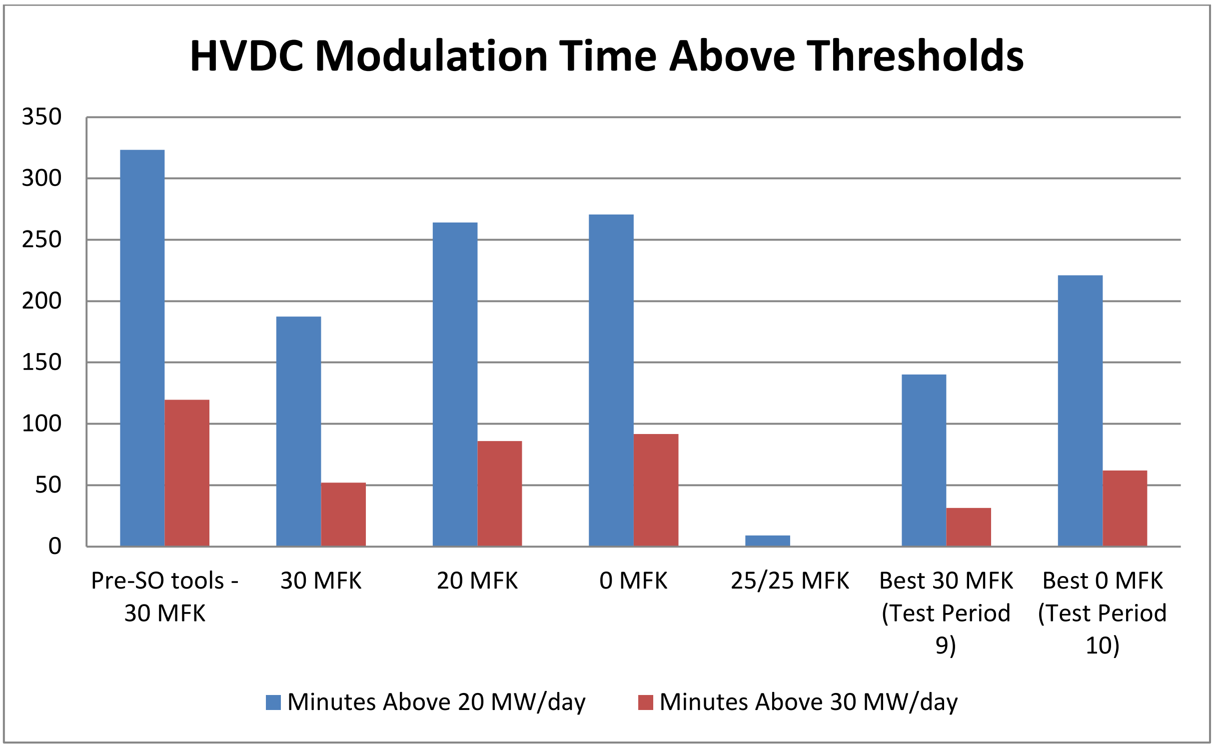


Figure 10 HVDC modulation analysis results – Time above 20 MW and 30 MW /day

The 30 MW HVDC modulation data has a 50th percentile value at almost 0 MW. The 20 MW MFK data showed a 50th percentile modulation slightly positive. A positive HVDC modulation meant additional MW from Haywards to Benmore. This indicated either the South Island having insufficient generation or the North Island having surplus generation and may be a result of a reduction of MFK in the North Island, the PSD settings used for the trial or another factor not considered in the analysis. The PSD could potentially be better tuned.

Table 6 HVDC modulation percentile values

Frequency Keeping Configuration	5th Percentile MW	50th Percentile MW	95th Percentile MW	5th – 95th Percentile Range
30 MW MFK Band	-21.15	0.30	22.92	44.07
20 MW MFK Band	-22.12	2.60	27.65	49.78
0 MW MFK Band	-22.74	1.73	27.63	50.38

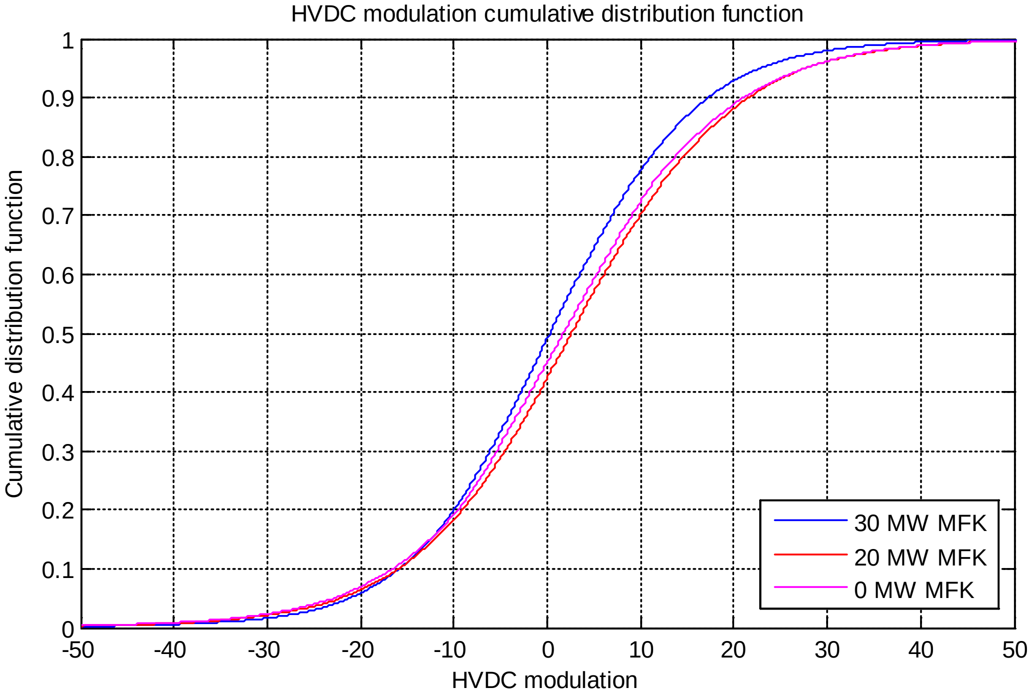


Figure 11 HVDC modulation cumulative distribution function

A full table of results is given in Appendix A.

5.5 FREQUENCY

Table 7 shows the North Island frequency standard deviations for the periods analysed. A full table of results for all test periods is in Appendix A: Full Overall Comparison Tables

Figure 12 shows the North and South Island frequency ranges for the total periods. The average frequency ± 3 standard deviations is plotted and gives the range of values between 0.3 percentile and 99.7 percentile.

From the analysis the following is noted:

- With 30 MW of MFK, the frequency standard deviations from TASC 49 analysis and during these test periods were very similar.
- With 20 MW of MFK, the South Island standard deviation was slightly lower than the figure for 30 MW of MFK. This value is within the range of values obtained for 30 MW of MFK, the lowest being test period 4 with a standard deviation of 0.0311. The data from these tests indicated there was no significant improvement or deterioration of frequency with 20 MW of MFK.
- During this testing, only one week was dedicated to testing operation with 20 MW of MFK. Although that test period produced results showing little to no deviation from operation with 30 MW, it is recommended that more testing be undertaken with 20 MW of MFK if it is being considered for normal operation.

Additional tests in May show higher frequency deviation than the original tests. The tests also reinforced the relationship between less MFK and increased frequency variation. The frequency variations seen in the tests were still within normal frequency bands and frequency ranges seen in previous operation.

Table 7 Frequency keeping configuration standard deviation values

Frequency Keeping Configuration	North Island Standard Deviation	South Island Standard Deviation
(TASC 49) SFK Benchmark	0.0522	0.0301
(TASC 49) MFK Trials with FKC Enabled: NI 20MW, SI 10MW	0.0383	0.0326
(TASC 49) Governor Response Only: MFK 0MW	0.0409	0.0349
30 MW MFK Band	0.03933	0.03369
20 MW MFK Band	0.03997	0.03428
0 MW MFK Band	0.04295	0.03642
25/25 MW MFK Band - FKC Disabled (30 MW NI Excluded)	0.0682	0.0300
25/25 MW MFK Band - FKC Disabled (30 MW NI Included)	0.0650	0.0300
50/25 MW MFK Band - FKC Disabled (15/11/14 - 15/12/14)	0.0653	0.0303

5.5.1 FKC DISABLED

Data from 15th November – 15th December 2014 with FKC disabled was analysed to provide a benchmark for 50 MW North Island and 25 MW South Island MFK operations. This analysis gave a North island frequency standard deviation significantly larger than the SFK benchmark identified in TASC 49.

South Island frequency showed less variation during test period 6 with FKC disabled, consistent with data analysed from 15th November – 15th December 2014.

With FKC disabled, North Island frequency operating with MFK had a much higher standard deviation than the South Island.

The results indicated that with a 25 MW North Island MFK band the standard deviation suffered no deterioration from with 50 MW of MFK. It was not evident if the departure of highly variable load in the current power system had a positive effect on operating the North Island with a lower MFK band.

However, if only the periods where 25 MW of MFK were contracted for the North Island are considered, the North Island frequency has a significantly higher standard deviation. Looking at Figure 12, the 0.3 to 99.7 percentile data included values outside the normal frequency range – 49.8 to 50.2 Hz.

It should be noted, though, that due to the time restrictions only 3 days of data were produced for analysis, about half of which was discarded when removing periods with 30 MW North Island MFK. To better understand operation of the North Island power system with 25 MW of MFK it is recommended to operate with 25 MW of MFK with FKC disabled in the North Island on a trial basis to establish whether satisfactory operation can be observed before being making a recommendation for FKC-disabled as normal operation.

Recommendation 1 – Utilise future FKC outages for trial operation with North Island 25 MW MFK.

The North Island frequency data for MFK operation with no FKC showed significantly more variation than the SFK benchmark provided from TASC 49. Given the upper and lower bounds of frequency (mean ± 3 standard deviations) were close to the limits of the normal frequency band, consideration could be given to operating the North Island with SFK (without MFK), when FKC is disabled.

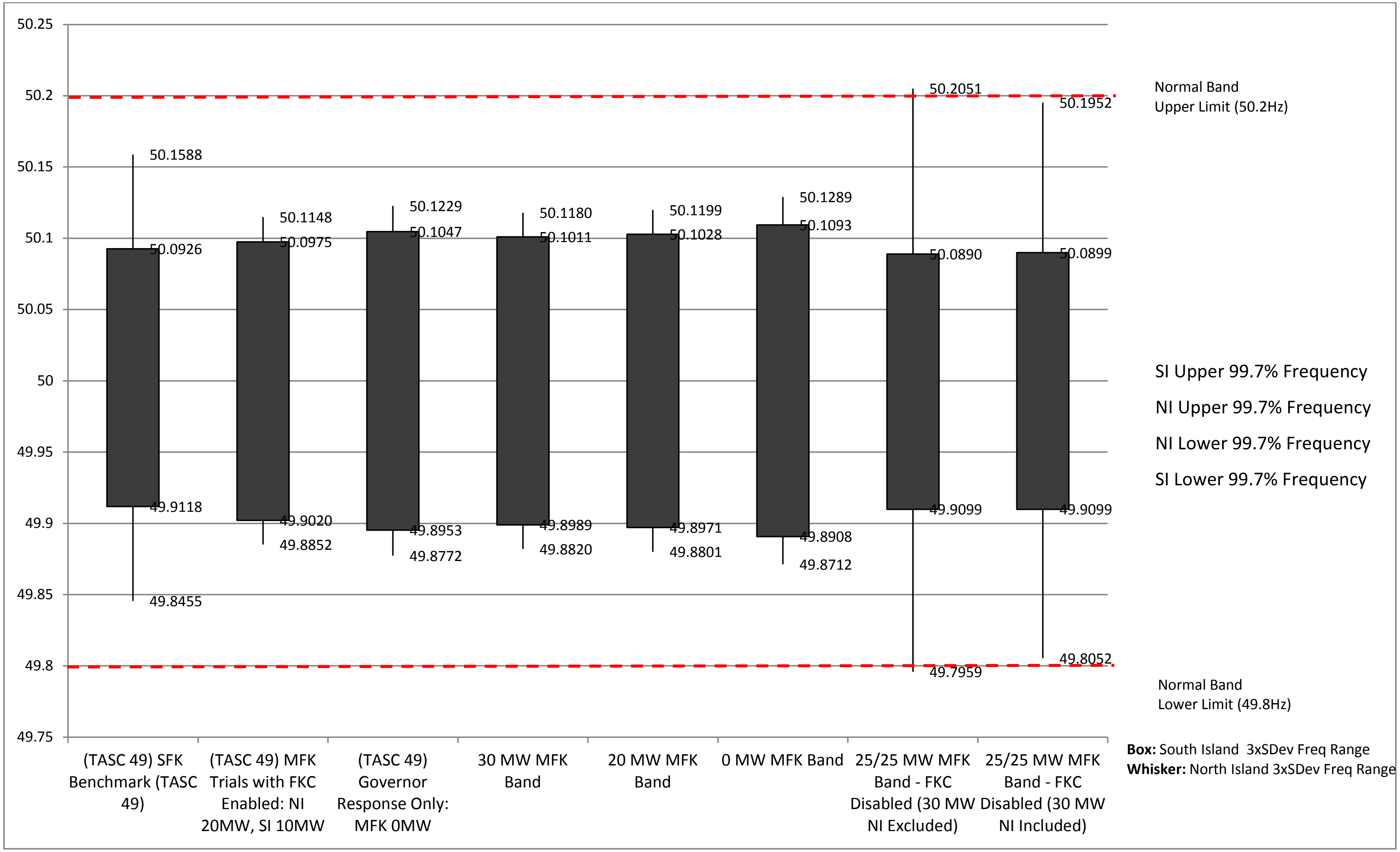


Figure 12 Frequency Comparison

5.6 GOVERNOR OFF DISPATCH

This section presents analysis of governor off dispatch during the test periods analysed. Test period 6 with FKC disabled was not analysed for governor off dispatch.

To compare governor off dispatch behavior (before the upgraded SO security tools were in operation) data from August 2015 was analysed for governors deviating from their dispatch setpoints.

Figure 13 shows the governor off dispatch standard deviation in per unit (pu) format grouped by MFK MW band.

From the standard deviation data the following is noted:

- Comparing 30 MW MFK pre-SO security tools data with similar data from after the tools upgrade an improvement was seen.
- There is a clear increase in governor off dispatch behaviour when operating with 0 MW of MFK.
- There is a marginal increase in governors off dispatch when operating with 20 MW of MFK.

Additional tests in May showed a similar trend in governor off dispatch to the original tests. The tests also reinforced the relationship between less MFK and increased governor off dispatch behaviour.

A table of results is in Appendix A: Full Overall Comparison Tables The absolute average data shows a similar trend to that seen in the standard deviation data, excepting the pre-SO security tools period which showed an absolute average much closer to 0 MW of MFK operation for Hydro Group 1.

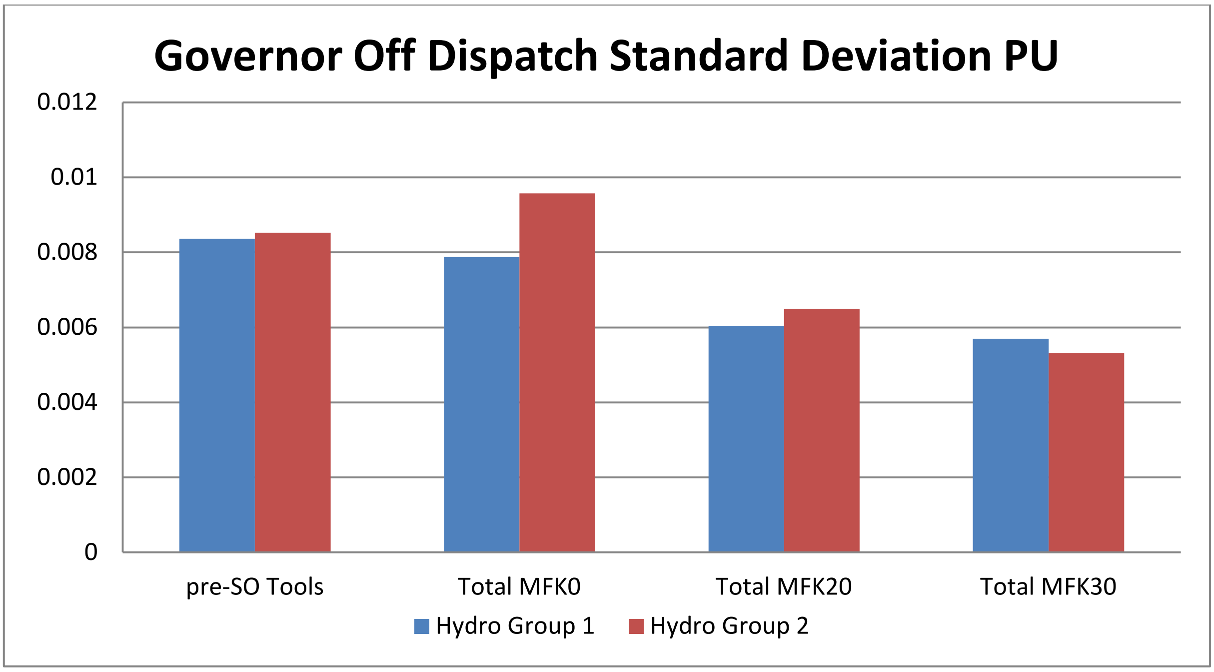


Figure 13 Governor off dispatch standard deviation pu.

6. ISSUES HIGHLIGHTED DURING TESTS

6.1 PSD NOT RESPONDING TO TIME ERROR INPUT

During test period 3 the PSD was noted to be unresponsive to the time error input. On 8th November at 16:40 the following was logged regarding time error correction:

"Time error in both islands consistently & slowly tracking more negative through entire shift with no attempt to correct it automatically. As getting close to -1 second, have manually adjusted target frequency in NI to return time error to zero. PSD & MFK settings all appear normal for the trial but response behaviour to time error does appear to have changed for the worst for unknown reasons."

This behavior appears to be an anomaly, as the time error input to the PSD was used and functioned correctly for the majority of the test periods.

6.2 GOVERNOR REGULATION CAUSING DIFFICULTY IN MANAGING CONSTRAINTS

During test period 8 (a 0 MW MFK test) increased governor action in the South Island was noted to have created difficulty managing Southland constraints. This was noted by the co-ordinator on shift and prompted intervention to the PSD settings. On 11th December, at 12:40 the following was logged regarding managing constraints due to generator units being off their dispatch setpoints:

"+20MW added to the NI PSD offset to help keep SI generators close to their set points to assist in managing Southland constraints."

Although this was noted in the 0 MW MFK test, this issue may also be experienced with 30 MW of MFK. With 30 MW of MFK, less governor regulation from dispatch was seen, though the magnitude of the governor regulation was still comparable with that seen with 0 MW of MFK. Figure 14 shows governor off dispatch swings of similar magnitude for both 0 MW and 30 MW of MFK operations.

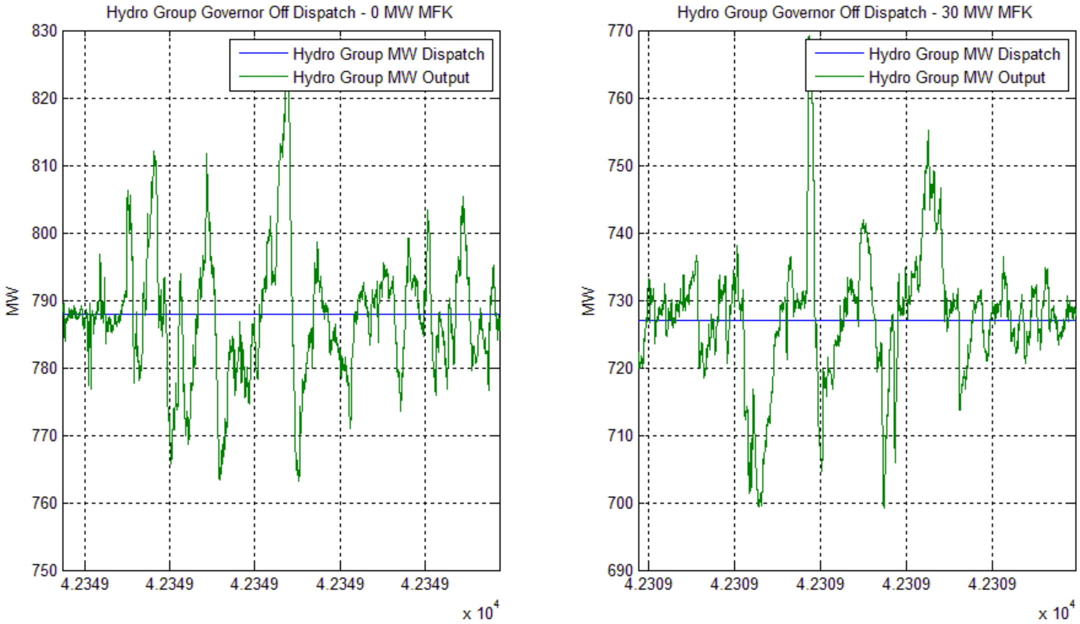


Figure 14 Governor off dispatch fluctuation example – 0 MW and 30 MW of MFK

6.3 INSUFFICIENT TIME ERROR CORRECTION IN 0 MW MFK TEST

During test period 13 with 0 MW MFK band, issues with the effectiveness of the PSD under the settings at the time were noted. Figure 15 (below) shows time error fluctuating above and below the 0.25 second threshold over a 2 hour period. The correction here was not sufficiently aggressive to move time error far enough away from the 0.25 second deadband. Therefore, when the correction was removed from the dispatch (once time error had dropped below 0.25 seconds) it quickly rose back to above 0.25 seconds.

This was noted by the co-ordinator on shift to have undesirable effects on dispatch, frequently removing then restoring 50 MW of generation to the dispatch. Figure 15 below shows this particular example (where the majority of the changes to dispatch were affecting one generation block).

However, it should be noted that this behaviour may also be experienced with 30 MW of MFK. Figure 16 below is an example of time error correction demonstrating similar saw-toothing behaviour during operation with 30 MW of MFK (seen in test period 3).

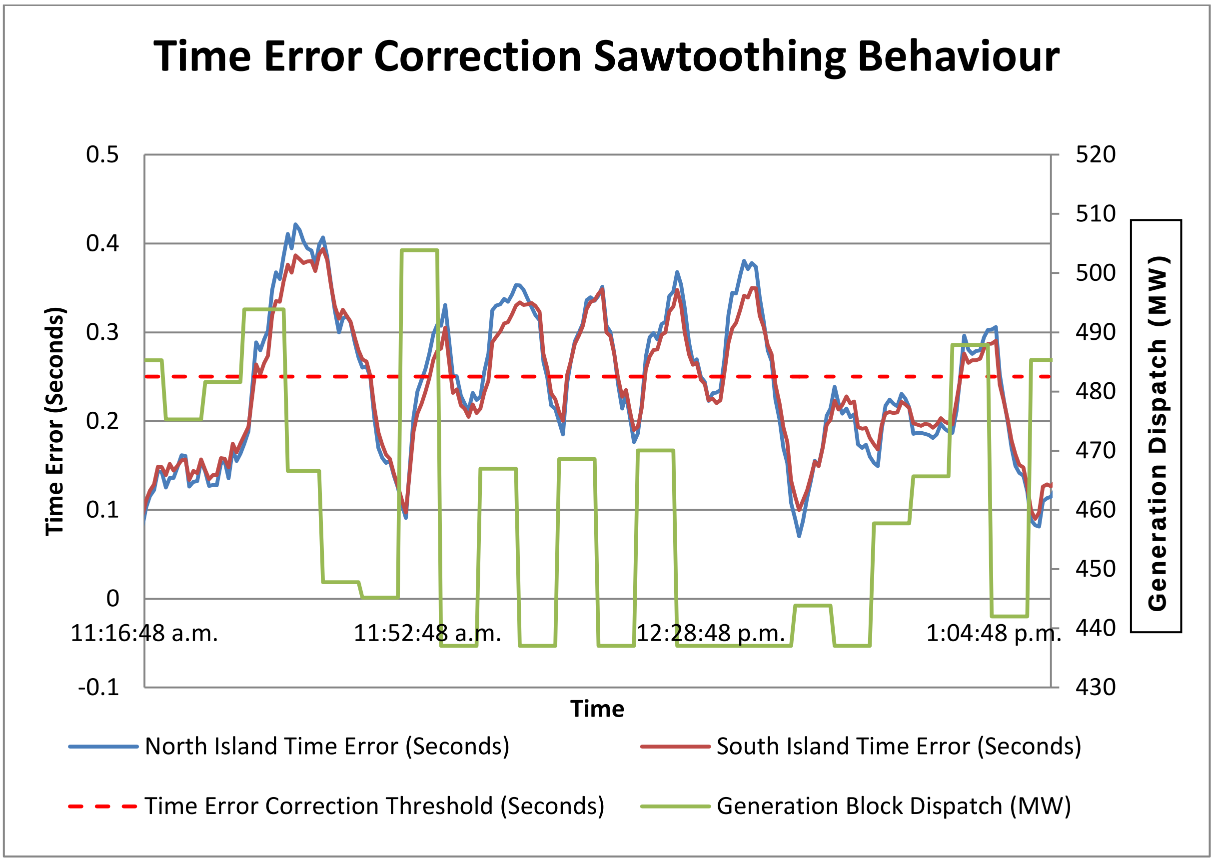


Figure 15 Time Error during saw-toothing behaviour experienced with initial test period 13 settings

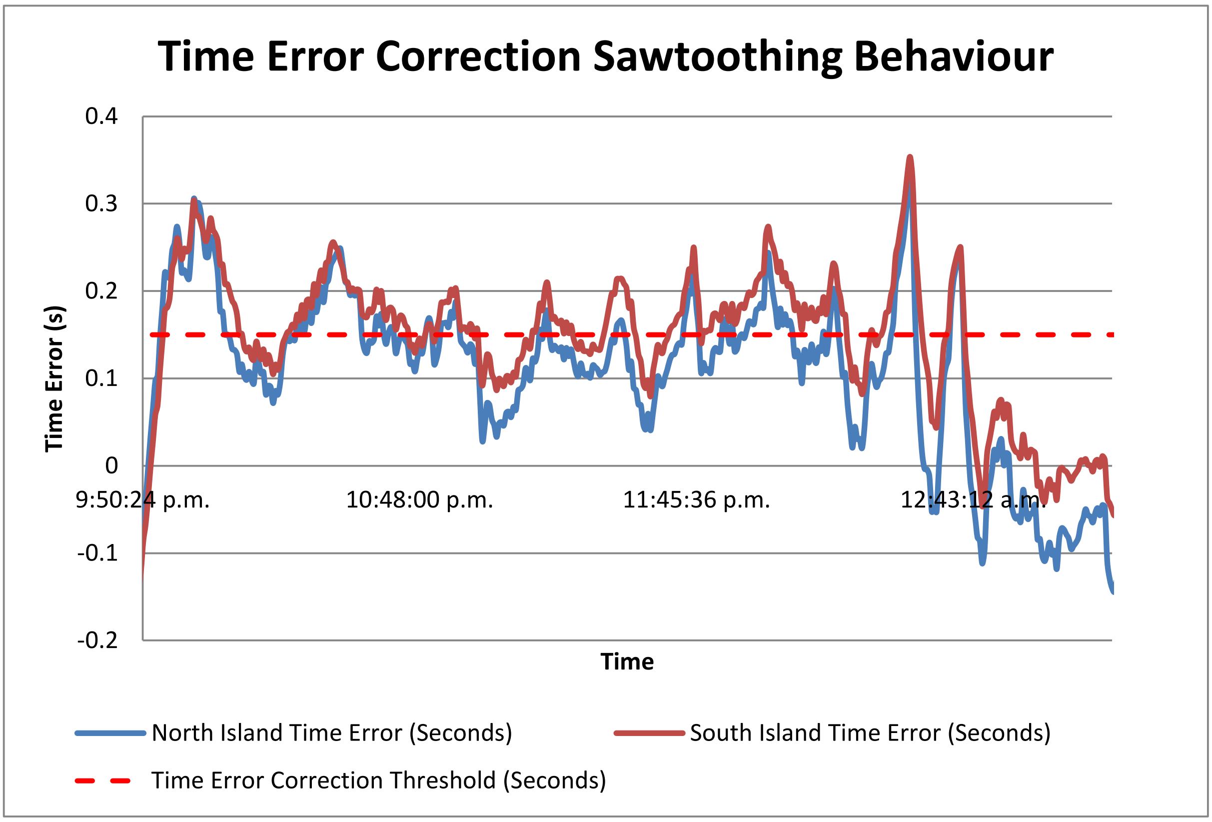


Figure 16 Saw-toothing behaviour of time error correction with 30 MW of MFK (Test Period 3)

Potentially, time error PSD calculation could be enhanced to help address the saw-toothing behavior seen on 10th February by using:

1. A proportional correction on the time error, where the MW correction applied to the PSD is proportional to the magnitude of the time error. This would mean more significant corrections are applied to higher deviations. A deadband such as used currently could be used along with the proportional correction to avoid constant PSD offsets being applied.
2. Hysteresis added to the time error correction, allowing the set value to be higher than the reset value. This would result in time error correction only being removed from the PSD when time error is well below the threshold to trigger correction.

Other PSD inputs may also be considered for enhancement aiming to reduce governor off dispatch behaviour and HVDC modulation.

Recommendation 2 – Consider further PSD enhancements.

7. Recommendations

Based on the analysis and experience during the testing, the following recommendations and considerations are made:

1. Utilise future FKC outages for trial operation with North Island 25 MW MFK.
2. Consider further PSD enhancement.
3. If reducing the MFK bands with FKC enabled is considered, the benefits of reducing MFK should be assessed against the impact it will have on governors off dispatch and HVDC modulation.

8. Conclusion

Following completion of the SO security tools project in September 2015, a series of tests were conducted to determine optimal PSD settings, test the use of augmented dispatch with FKC, and test the impact of operating with reduced MFK bands.

A total of 16 test periods were conducted, 3 of which were undertaken following identification of the need for more tests. The test periods are summarised as follows:

- 4 consisting of 30 MW of MFK, automatic PSD, manual send dispatch
- 5 consisting of 30 MW of MFK, augmented dispatch
- 4 consisting of 0 MW of MFK, augmented dispatch
- 2 consisting of 20 MW of MFK, augmented dispatch
- 1 consisting of operation with FKC disabled, 25 MW of MFK in each island.

The test periods were analysed for time error, MFK regulation, HVDC modulation, frequency variation, and governors off dispatch.

The data for 30 MW of MFK operations compared with 20 MW of MFK operations showed no indication of deterioration in performance of time error control or frequency. governors off dispatch and HVDC modulation showed a slight increase with 20 MW of MFK (though still within the range of values seen in some 30 MW MFK test periods).

The data for 30 MW of MFK operations compared with 0 MW of MFK showed an increase in frequency variation, governors off dispatch, time error control and HVDC modulation. The control of time error, although better with 30 MW of MFK, was managed to well within its limits with dispatch. The increase seen in frequency variation and time error are acceptable as they are within the range of previous acceptable operation. HVDC modulation and governors off dispatch may require investigation and consultation with industry to determine what is acceptable for normal system operation.

If reducing the MFK bands with FKC enabled is to be operationally implemented, the benefits of reducing MFK should first be assessed against the impact on governors off dispatch and HVDC modulation.

With FKC disabled the full range of test data indicated no deterioration of frequency between operation with 50 MW of MFK, and 25 MW of MFK.

However, if the periods where 30 MW of MFK rather than 25 MW of MFK was procured are removed from the analysis, the data indicated a small deterioration of frequency, placing the upper and lower bounds (0.3% - 99.7%) just outside the normal frequency band of 49.8 – 50.2 Hz. However, by removing the 30 MW MFK periods a significant amount of data is lost from an already small analysis period, reducing confidence in results drawn from the dataset.

The results of this analysis do not materially impact the recent Authority initiative to shift the MFK bands to 15 MW North Island, 15 MW South Island. The analysis of 20 MW of MFK operation did not reveal any negative effects on operation which could be attributed to the equal split of MFK between the North and South Island.

APPENDIX A: FULL OVERALL COMPARISON TABLES

Table 8 Frequency results

Test Period	Island	Standard Deviation	Average	Deviation from 50 Hz absolute average	Number of values in dataset (1 week at 2s data resolution = 302401)	Frequency Keeping Configuration
0	North Island	0.0653	50.00014	0.0508	172835	Pre-SO tools - 30 MFK
1	North Island	0.0410	49.99996	0.0314	302157	30 MFK
2	North Island	0.0411	50.00002	0.0319	302345	30 MFK
3	North Island	0.0398	49.99997	0.0307	302398	30 MFK
4	North Island	0.0366	49.99999	0.0282	302394	30 MFK
5	North Island	0.0365	49.99999	0.0281	302393	30 MFK
6	North Island	0.0682	50.00045	0.0513	133036	25/25 MFK
7	North Island	0.0373	49.99991	0.0287	302392	30 MFK
8	North Island	0.0435	50.00005	0.0330	302318	0 MFK
9	North Island	0.0374	49.99997	0.0287	200570	30 MFK
10	North Island	0.0423	50.00001	0.0327	302375	0 MFK
11	North Island	0.0382	49.99995	0.0293	302395	20 MFK
12	North Island	0.0399	49.99998	0.0308	302400	30 MFK
13	North Island	0.0399	50.00026	0.0309	180508	0 MFK
14	North Island	0.0432	50.00001	0.0334	302372	30 MFK
15	North Island	0.0448	50.00005	0.0350	302291	0 MFK
16	North Island	0.0417	49.99998	0.0321	302290	20 MFK
0	South Island	0.0303	50.00010	0.0225	172835	Pre-SO tools - 30 MFK
1	South Island	0.0354	49.99997	0.0272	302157	30 MFK
2	South Island	0.0355	50.00002	0.0276	302345	30 MFK
3	South Island	0.0335	50	0.0260	302398	30 MFK
4	South Island	0.0311	49.99998	0.0239	302394	30 MFK
5	South Island	0.0315	49.99996	0.0243	302393	30 MFK

6	South Island	0.0300	49.99989	0.0225	133036	25/25 MFK
7	South Island	0.0319	49.9999	0.0246	302392	30 MFK
8	South Island	0.0347	49.99998	0.0268	302318	0 MFK
9	South Island	0.0321	49.99997	0.0246	200570	30 MFK
10	South Island	0.0370	50.00002	0.0286	302375	0 MFK
11	South Island	0.0323	49.99995	0.0248	302395	20 MFK
12	South Island	0.0334	49.99998	0.0259	302400	30 MFK
13	South Island	0.0342	50.00020	0.0264	180508	0 MFK
14	South Island	0.0377	50.00000	0.0291	302372	30 MFK
15	South Island	0.0387	50.00003	0.0302	302291	0 MFK
16	South Island	0.0362	49.99999	0.0278	302290	20 MFK

Table 9 Time error results

Test Period	Average	Absolute Average	Minutes Above 0.3 seconds/day	Minutes Above 0.5 seconds/day	Number of values in dataset	Frequency Keeping Configuration
1	-0.007	0.131	97	22	10081	30 MFK
2	0.026	0.119	58	11	10011	30 MFK
3	-0.091	0.161	208	59	10081	30 MFK
4	0.051	0.15	163	49	10081	30 MFK
5	0.097	0.155	182	53	10081	30 MFK
6 – North Island	-0.065	0.262	408	177	10321	25/25 MFK
6 – South Island	-0.038	0.085	41	16	10321	25/25 MFK
7	-0.011	0.102	67	30	10081	30 MFK
8	0.182	0.24	346	160	9747	0 MFK
9	-0.069	0.101	21	2	10081	30 MFK
10	-0.002	0.131	90	28	10081	0 MFK
11	0.024	0.096	32	6	10081	20 MFK
12	-0.12	0.168	64	0	10081	30 MFK
13	0.026	0.151	84	22	6031	0 MFK
14	-0.003	0.142	122	27	10081	30 MFK
15	0.033	0.116	90	13	10081	0 MFK
16	-0.003	0.142	122	37	10081	20 MFK

Table 10 MFK regulation

Test Period	Average	Absolute Average	Minutes Above 66.7% MW/day	Minutes Above 93.3% MW MW/day	Number of values in dataset	Frequency Keeping Configuration
1	-6.535	13.383	367	79.714	10081	30 MFK
2	-6.43	13.142	352.857	67.857	10081	30 MFK
3	-6.764	12.686	314.286	57.571	10081	30 MFK
4	-5.619	13.406	366.286	80.143	10081	30 MFK
5	-5.619	13.406	366.286	80.143	10081	30 MFK
6 – North Island	-1.4678	12.8422	481	248	4860	25/25 MFK
6 – South Island	-6.33	8.926	188	54	4860	25/25 MFK
7	-7.545	12.805	326.143	64.000	10081	30 MFK
8					0	0 MFK
9	-5.43	12.299	301.571	63.857	10081	30 MFK
10					0	0 MFK
11	-2.960	8.681	334.571	65.000	10081	20 MFK
12	-6.588	12.358	295.429	47.571	10081	30 MFK
13					0	0 MFK
14	-6.637	12.971	332.286	67.286	10081	30 MFK
15						0 MFK
16	-2.267	8.764	348.714	67.429	10081	20 MFK

Table 11 HVDC modulation

Test Period	Average	Absolute Average	Minutes Above 20 MW/day	Minutes Above 30 MW/day	Number of values in dataset	Frequency Keeping Configuration
1	-3.637	10.32	179.571	49	10081	30 MFK
2	-0.118	9.839	160.143	46.143	10081	30 MFK
3	-1.744	10.692	199.286	51.714	10081	30 MFK
4	2.612	11.146	212.571	65.429	10081	30 MFK
5	7.337	11.881	242.429	67.857	10081	30 MFK
6	1.403	5.123	7.116	0	10321	25/25 MFK
7	1.609	10.189	165.429	44.143	10081	30 MFK
8	3.248	12.495	293.286	95	10081	0 MFK
9	-1.214	9.537	140.286	31.571	10081	30 MFK
10	-0.435	11.251	221.143	62	10081	0 MFK
11	2.749	11.101	220.286	68.714	10081	20 MFK
12	-2.499	9.885	161.143	35	10081	30 MFK
13	0.555	12.145	154.286	54.143	6031	0 MFK
14	2.230	11.350	225.286	76.714	10081	30 MFK
15	4.170	14.360	367.143	140.857	10081	0 MFK

16	2.640	12.870	307.857	103.429	10081	20 MFK

Table 12 Governor off dispatch (Hydro Group 1)

CLU	average	absolute average	standard deviation	Data points used
pre-SO Tools	0.00442	0.00728	0.00836	67453
0 MFK	0.00127	0.00617	0.00787	72329
20 MFK	0.00121	0.00459	0.00603	54617
30 MFK	0.00200	0.00457	0.00570	201897

Table 13 Governor off dispatch (Hydro Group 2)

	average	absolute average	standard deviation	data used
pre-SO Tools	-0.00035	0.00596	0.00852	106843
0 MFK (Total)	-0.00141	0.00735	0.00958	150698
20 MFK (TP11)	-0.00109	0.00469	0.00649	102799
30 MFK (Total)	-0.00047	0.00373	0.00531	417594