TRANSPOWER

Quarterly System Operator and system performance report

For the Electricity Authority

July to September 2022

Report Purpose

This report is Transpower's review of its performance as System Operator for Q1 2022/23 (July to September 2022), in accordance with clause 3.14 of the Electricity Industry Participation Code 2010 (the Code).

As this is the final self-review report of the quarter, additional information is included as per SOSPA clause 12.3. This includes performance against the performance metrics year to date, and actions taken in regard to the System Operator business plan, statutory objective work plan, participant survey responses, and any remedial plan agreed under clause 14.1(i). A summary of technical advisory services for the quarter is also provided.

A detailed system performance report (Code obligated) is provided for the information of the Electricity Authority (Authority).

Contents

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Commentary

This section provides a high-level update for this quarter. The remainder of the report provides supporting detail in two sections:

- System Operator performance
- System performance

Update (July to September 2022)

Note: This report period does not contain Friday 7 October when a generation shortfall notice was sent out for unplanned outage of Haywards filter 4B leading to a reduction in HVDC capacity. This event has not been classified as a significant event nor a breach. However, it resulted in an under-frequency event that will be reported in subsequent monthly reports.

Security of Supply and market information

- Hydro storage has remained high with several large inflow events impacting both islands. Average prices have dropped in response.
- Demand peaks continue to rise with the top 10 peak demands on record now from 2021 and 2022.
- With lower prices, thermal generation has not been incentivised to offer, but when forecast energy from intermittent generation does not occur in real time this has resulted in short term capacity issues.
- We have set up additional residual monitoring and reporting to ensure we can notify the market and allow participants to make informed decisions when capacity problems have been highlighted both in the NZGB and real time timeframes.
- We have implemented additional data feeds and expert advice into our forecasting processes. These are in addition to the previous improvements, which resulted in a 30-50% forecasting improvement.

Projects and TAS work

- Real Time Pricing (RTP): Most of the Phase 3 testing has been completed with the balance scheduled for completion in early October, along with a final deployment dress rehearsal. All preparation actions are being worked through for deployment on 18 October. Phase 4 development is underway, although this is four weeks later than planned, due to illness impacts in April through to July.
- Operational Excellence: We are translating the recommendations from our external consultant's report into a work programme which includes identifying priorities, resources and interconnectedness with other work. The multi-year programme plan will be complete in December.
- Future Security and Resilience (FSR) programme: The FSR phase 2 roadmap has been published. This sets out an 8–10-year programme of work and is an integral step in addressing the challenge of maintaining a secure and resilient

power system. The System Operator continues to support ongoing discussions with the Authority and provide inputs to the issues paper as requested.
- Customer Portal: The Planned Outage Coordination Process (POCP) application has been successfully deployed and the New Zealand Generational Balance (NZGB) application is progressing to target.
- Extended reserves: TAS 103 has been set up for the next stage of this work and the statement of work for the implementation is being finalised.
- KPI Refresh Programme: We are now working with the Authority to roll out performance metrics reporting with an external focus, based on agreed External Outcomes. We held the first of six sessions with both System Operator and Authority participation, and the remaining sessions will run through to early November.

Risk and Assurance

- In line with the Government's announcement to remove the COVID-19 traffic light system, all restrictions have been removed.
- The Defects and Enhancements audit was completed this quarter, the System Operator Load Forecast audit fieldwork commences on 17 October and the three remaining System Operator Audits will be completed during this financial year.
- We are holding workshops in October for the November Risk Control Self-Assessment. We will be assessing five critical risk controls: 24 hour real-time; business support functions; incident preparedness and response; power system planning; and support of critical tools and systems.

Customers and other relationships

- In the week ahead of 12 August, we published Customer Advice Notices and held two online industry briefings to provide information on a forecast generation capacity shortfall.
- We continue to leverage our international relationships to understand how others are dealing with the new challenges facing the industry. This includes an ESIG webinar, an ENA technical workgroup, and separate discussions with AEMO and UK industry energy players.
- We are also working with NZ industry working groups, including the Flex Forum which is exploring how to best design and procure flexibility services from market participants and consumers.
- We have worked with SolarZero to determine how they could offer 6-second and 60-second reserve into the market by aggregating household level batteries

System events

- Ranil de Silva (PBA Consulting) completed the independent review of the System Operator’s performance during the grid emergency on 23 June 2022. The PBA report notes that the new demand management processes implemented post 9 August 2021 were successfully followed to manage the generation shortfall with minimal disruption to consumers.

- On 30 July 2022, an under-frequency event occurred when Huntly unit 5 tripped while at 190 MW.
- On 17 August, a fault of the Grid Owner's HVDC Pole 2 converter transformer neutral earthing resistor at Benmore required the System Operator to take action to reclassify an HVDC bi-pole tripping as a contingent event in the market system between 03:30 to 11:30.

System Operator performance

1 Customers and other relationships

System Operator Industry Forums

Our industry forums, used to brief a wide range of participants and stakeholders on market updates, outage information, the current NZGB balance forecasts and a general operational update, continue to be well-received. They have been a useful vehicle to communicate the effect of several cold snaps of weather on the residual generation available and proactively coordinate and drive a response from the market, especially over the peaks which were likely to be tight.

12 August low residual situation

In the week ahead of 12 August, we published Customer Advice Notices and held two online industry briefings to provide information on a forecast generation capacity shortfall. Our briefings covered the differences in wind forecasts and offers and we saw improvements in wind offers through the week, as well as bids and offers from supply and demand side. Sufficient generation was not offered until the evening of 11 August. At 3am on 12 August some thermal generation assets had operational issues, but these were resolved in time to provide adequacy over the morning peak. We debriefed industry on this event in the following week and received positive feedback from industry and the Authority on our handling of this event.

Energy Systems Integration Group (ESIG)

We attended the ESIG webinar hosted by National Grid System Operator on good practices for operating the UK's Net-zero energy transition across Grid Forming code development, stability constraint management, system strength management, and inertia management.

Energy Networks Association (ENA)

We attended the ENA Smart Technology Working Group meeting on 20 July. Of interest was the group's discussions on the South Island Distribution Group (SIDG) DSO Roadmap, Flex Forum progress, and their future workplan.

Australian Energy Market Operator (AEMO)

On 22 July, we organised a discussion with AEMO's forecasting team. It was an interesting and informative discussion about the realities of forecasting highly uncertain resources at scale. Both parties expressed a genuine willingness to share information with each other.

National Grid Electricity System Operator, UK Energy Systems Catapult, Scottish Power Transmission

We have coordinated and held a series of knowledge sharing sessions with counterparts in the UK, focusing on system operation challenges and market design opportunities for a low carbon energy system. We identified and progressed a range of topic areas where there are opportunities for both parties to learn from each other.

Flex Forum Industry Working Group

Throughout August, our teams supported and informed this industry working group which is exploring how to best design and procure flexibility services from market participants and consumers. This work ensures that new developments around flexibility services at a distribution network level integrate with and support national electricity system operation for the benefit of consumers.

Exploring provision of ancillary services by new technologies
We set up a project team to work with SolarZero to determine how they might offer into the reserves market with a new technology and business model. This has now been formalised and SolarZero are providing 6-second and 60-second reserve by aggregating household level batteries.

2 Risk & Assurance

COVID-19
A risk assessment was carried out in August regarding access to the control rooms. At that time, in line with the organisational risk matrix, this enabled us to reinstate external visits to the control rooms. Visitors were still asked to undertake a RAT test and wear masks; entry was limited to no more than five at a time and for a maximum time of 15 minutes.

In mid-September, in line with the Government announcement of the removal of the COVID-19 traffic light system, all restrictions have been removed, including in the control rooms.

Business assurance audits
The Defects and Enhancements audit concluded this quarter and will be shared internally and with the Authority in due course. The System Operator Load Forecast audit fieldwork commences on 17 October. Three remaining System Operator Audits (Voltage stability assessment tool (VSAT) change management, ancillary service contract management, real-time management of simultaneous feasibility test (SFT) constraints will take place during this financial year.

Risk Management Framework
A paper outlining the System Operator's risk management framework was presented at the 8 August 2022 Electricity Authority System Operator Committee (SOC) meeting. The SOC commented that they have taken comfort in our approach to risk management having seen the paper.

We are drafting a paper for the Authority's November SOC on the System Operator's role and risks around "failing to maintain service levels for consumers".

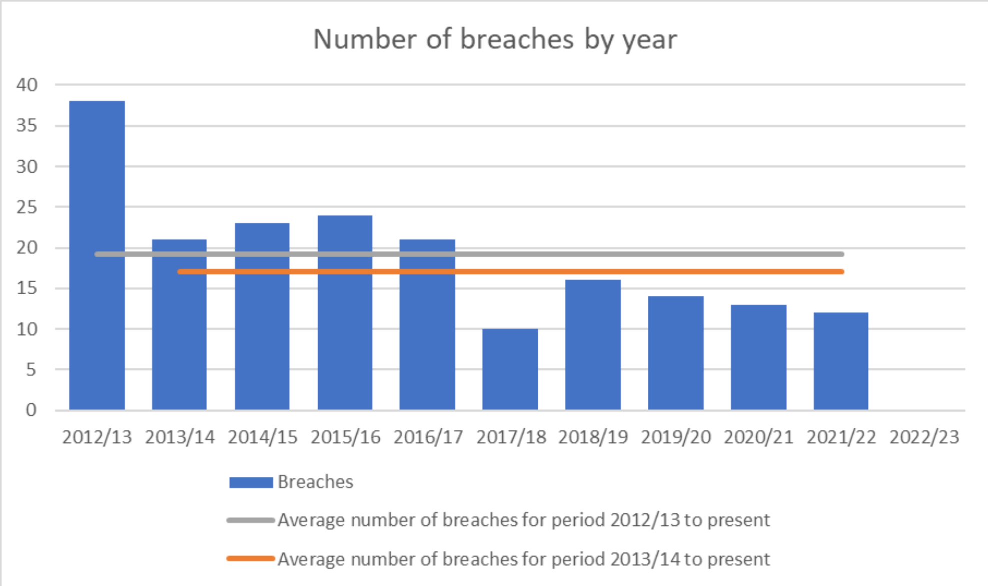
We are holding workshops in October for the November Risk Control Self-Assessment. We will be assessing five critical risk controls: 24 hour real-time; business support functions; incident preparedness and response; power system planning; and support of critical tools and systems.

3 Compliance

July - September
We did not self-report any System Operator breaches in this reporting period.

9 August 2021 event

A directions conference with the Rulings Panel was initially scheduled for 10 October, prior to which the parties are required to submit a joint memorandum identifying the agreed facts and issues to be determined. The Rulings Panel has since granted a 6-week extension until 21 November for the directions conference hearing.



The Authority closed one System Operator breach in August, two in September, and since the end of Q1, a further breach was closed in October. We currently have eleven outstanding breaches with the Authority compliance team.

Appendix A shows instances where the System Operator has applied discretion under 13.70 of the Code. Note - In recent months, discretion has been reclassified to include the process to manage generators on minimum MW values overnight. As a result, the list of discretions in this report is much larger than previously recorded. There will also be further actions recorded as discretions when RTP goes live in November. We will be assessing if there is benefit in reporting these two new categories of discretion in this report as the latest information distorts any previous trends.

4 Impartiality of Transpower roles

We have three open items in the Conflict of Interest Register (below). These are being actively managed in accordance with our Conflict of Interest procedure.

Item 42 was closed during this reporting period. The item related to a former employee of Mercury managing the KPO upgrade. The System Operator employee has now been in the role for 12 months and the controls remain effective. The System Operator is comfortable there is no longer a conflict of interest.

System Operator Open Conflict of Interest Issues		
FID	Title	Managed by
29	**Preparing the Net Benefit test – System Operator involvement:** The System Operator is reviewing how it can provide information for use by the grid owner undertaking a Net Benefit Test.	Operations Planning Manager

System Operator Open Conflict of Interest Issues		
FID	Title	Managed by
40	**General System Operator/Grid Owner dual roles:** This is a general item that will remain permanently open to cover all employees with a dual System Operator/grid owner role. The item documents the actions necessary to ensure impartiality in these circumstances; these items will be monitored to ensure their continue effectiveness.	SO Compliance & Impartiality Manager
41	**General relationship situation:** This is a general item that will remain permanently open to cover all potential conflicts of interest arising under a relationship situation. This item documents the actions necessary to prevent an actual conflict arising and will be monitored by the SO Compliance & Impartiality Manager to ensure their continued effectiveness.	SO Compliance & Impartiality Manager

4.1 System Operator independence audit

Deloitte has largely completed its fieldwork for the 2022 System Operator independence audit of the outage planning process. The System Operator expects to receive Deloitte's draft report in October, with a final report soon after.

The 2023 System Operator independence audit is scheduled for Q2 and Deloitte is currently finalising the scope.

5 Project updates

5.1 Market design and service enhancement project updates

Progress against high-value, in-flight market design and service enhancement projects is included below along with details of any variances from the current capex plan.

Future Security and Resilience (FSR) Programme
In August, the Authority Board approved the publishing of the FSR phase 2 roadmap. The roadmap sets out an 8–10-year programme of work required to enable New Zealand to address the challenges and opportunities associated with maintaining a secure and resilient power system.

The Authority is progressing the FSR programme, initially focussing on updates to Part 8 of the Code with an intent to release an issues paper as a first step. The System Operator continues to support ongoing discussions with the Authority and provide inputs to the issues paper as requested.

Real Time Pricing (RTP)
The Electricity Authority announced its final decision on the Real Time Pricing Code amendment publicly on 27 September, which confirms deployment and go live dates.

Most of the Phase 3 testing has been completed with the balance scheduled for completion in early-October, along with a final deployment dress rehearsal. All preparation actions are being worked through for deployment on 18 October. Phase 4 development is underway, although this is 4 weeks later than planned, due to illness impacts in April through to July.

A change request for additional budget will be discussed with the Authority in early-October.

As part of efforts to ensure market participants understand the impact of Real Time Pricing on their operations, we are running an industry briefing on 12 October. Representatives from the Electricity Authority and NZX will support our presenters and help answer any questions.

Operational Excellence
Our external consultancy providers delivered the final report of findings from the Operational Excellence work in August. The report includes a high-level 5-year roadmap for recommended activities. The final outputs from this work were presented to the project governance team on 1 September.

We are translating these recommendations into a work programme, including identifying priorities, resources and interconnectedness with other work. The multi-year programme plan will be complete in December. We have identified a series of ‘quick start’ initiatives to begin immediately, based on their urgency, importance, or ability to underpin and inform wider programme initiatives. These include preliminary planning for an industry exercise to be held prior to winter 2023, establishment of procedure assurance, and foundational resource planning including development of a skills architecture.

Customer Portal Programme
The new Planned Outage Coordination Process (POCP) application was successfully deployed in the Operations Customer Portal on 12 July. Training videos are available on the Transpower YouTube channel.

Our next launch, development of the new New Zealand Generation Balance (NZGB) application, is on target to be available through the Operations Customer Portal from early November this year. This will provide improved navigation and user experience in the tool and integration with POCP. Once the new NZGB application is delivered we will progress with the final phase of the programme, the implementation of the Dispensations and Equivalence application in the portal.

KPI Refresh Programme
Work is underway on the next stage of the KPI refresh programme, which will roll out performance metrics reporting with an external focus, based on External Outcomes discussed with the Authority. We held the first of six sessions, with both Operations and Authority participation, and the remaining sessions will run through to early November. These sessions will develop metrics which will be tracked to provide assurance of System Operator activities. Metrics developed will inform a revised incentives agreement with the Authority for 2023/24.

6 Technical advisory hours and services

The System Operator and the Authority are finalising the TAS 103 statement of work for the next phase of the Extended Reserves implementation. The scope for TAS 103 includes working through the internal assessment planning and preparation work with the North Island Connected Asset Owners (CAOs) ahead of the transition from a 2-block to 4-block AUFLS.

The following table provides the technical advisory hours for Q1 2022/23 and a summary of technical advisory services to which those hours related (SOSPA 12.3 (d) refers).

TAS Statement of Work (SOW)	Status	Hours worked during Q1
TAS SOW 102 – Reviewing Part 8 of the Code – Common Quality	In progress	208.75
Total hours		**208.75**

7 Outage planning and coordination

Upper North Island voltage management

A System Operator voltage management working group provided analysis to the Grid Owner given the restrictions on switching of cable circuits, particularly the Pakuranga-Whakamaru circuits. The System Operator is likely to request a continuous outage over the shoulder and summer months of one Pakuranga-Whakamaru circuit. The outage timing will depend on system conditions and will be to assist with the management of high overnight voltages. Once removed, the circuit will be available to be returned to service for security reasons but will otherwise remain out of service. Our analysis suggests that, depending on peak demand levels, there are periods in November and early-December when the cable may need to be returned to service to manage voltage stability or thermal contingencies during concurrent outages of Huntly unit 5 and other 220 kV transmission outages.

Outage Planning – near real time

Outage numbers in the later part of August dropped off, primarily because of the Grid Owner's transition to new service providers, although the transition has also seen an increase in the number of changes to outages in short notice. Outage numbers for September and October climbed and we are seeing larger outage numbers for November as we come into better weather. There have been several complex assessments associated with grid changes such as the new Bombay interconnecting transformer.

New Zealand Generation Balance (NZGB) potential shortfalls

The System Operator has published monthly NZGB reports covering potential shortfalls and an NZGB assessment and Customer Advice Notices specifically covering the early September shortfalls. These have also been communicated in the fortnightly System Operator Industry Forum. The message from the System Operator has been to recommend that the Grid Owner and Asset Owners move their outages (which may remove or reduce generation output) outside of these periods of higher risk and avoid scheduling any further outages for this period.

As of early October, the NZGB tool is forecasting no shortfalls for the next 200 days. Looking ahead to spring and summer, margins are increasing, although there are some lower margin periods in mid-November and in February due to generation plant outages and the HVDC outages respectively. We will be monitoring these periods. The November lower margin periods coincide with a planned Kupe gas outage.

8 Power systems investigations and reporting

No new investigations to report on this quarter.

9 Performance metrics and monitoring

The following dashboard shows System Operator performance against the performance metrics for the financial year to date as required by SOSPA 12.3 (a).

Only those metrics with a weighting are used in the calculation of the System Operator score and incentive payment.

		Annual Target	Actual to date	Points
Smart about money				
Perception of added value by participants		80%	N/A	
Customers are informed and satisfied				
Annual participant survey result		83%	N/A	5
Annual participant survey result response rate - First tier stakeholders		80%	N/A	
Future thinking and insights	Future thinking report	≥ 1	0	5
	Longer Market Insight reports	≥ 4	0	5
	Bite-sized Market Insights	≥ 45	13	
Quality of written reports		100% of standard	100%	
Role impartiality		80%	N/A	5
Responding to requests for information from the Authority		100% by agreed deadline	N/A	
Code compliance maintained and SOSPA obligations met				
Market breaches remain below threshold		≤ 3 @ ≥ $40k	0	10
Breaches creating a security risk - below threshold/within acceptable range		≤2	0	10
On-time SOSPA deliverables		100% (49)	100% (7)	10
Successful project delivery				
Project delivery	Service Maintenance projects	≥ 70% on time	0 to date	
		≥ 70% on budget	0 to date	
	Market Design and Service Enhancement projects	≥ 70% on time	0 to date	
		≥ 70% on budget	0 to date	
Accurate capital planning		≥ 50%	N/A	10
Commitment to optimal real time operation				
Sustained infeasibility resolution		80% ≤ 10am or equiv	92%	5
High spring washer resolution		80% ≤ 10am or equiv	0 to date	
Fit-for-purpose tools				
Capability functional fit assessment score		76.00%	N/A	
Technical quality assessment score		70.00%	N/A	
Sustained SCADA availability		99.90%	99.99%	10

Maintained timeliness of schedule publication	99.00%	99.99%	10
We prepare for, manage and review events *			
Event preparedness	Score 1 (worst) to 5 (best)	N/A	12
Event management		N/A	13
Event review and improvements		N/A	12

* These will be updated in late October

9.1 Dispatch accuracy dashboard

Since 2019/20, we have been reporting the Dispatch Accuracy dashboard for energy dispatch as part of this report. This is a means of monitoring overall industry performance.

In addition, we also produce a Dispatch Accuracy dashboard for reserves to identify trends and patterns in reserve management.

For this financial year, both dashboards are contained in Appendix B, along with an explanation of the methodology we used to create the dashboards.

Both dashboards continue to evolve and provide a good mechanism to see how changes to the power system, such as how the introduction of more wind generation, affect performance.

We will continue to assess the value of these dashboards once we start to develop new measures as part of the KPI refresh project.

Below are instances of variations we have observed this quarter.

Energy

Overall industry performance this quarter – July to September 2022

- *Application of discretion under 13.70 (July to September)*
    - As has been noted in section 3 of this report and Appendix A, we are no longer comparing discretions from this period to previous periods in this dashboard on a like-for-like basis. In recent months, discretion has been reclassified to include the process to manage generators on minimum MW values overnight. As a result, the number of discretions in this report is much larger than previously recorded.
- *HVDC modulation (general)*
    - As noted in previous quarters, we continue to see a rising trend in the % of minutes where maximum modulation exceeds 30 MW. We are keeping a close eye on this measure, as the increase of intermittent generation, currently new wind generation, is the main driver of HVDC deviation from dispatch. We will be revisiting the 30 MW band if this trend continues.
    - This change is more pronounced this quarter as this quarter is affected by higher seasonal wind generation.

Optimal dispatch this quarter

Last quarter we observed a slight dip in the overall optimal dispatch percentage in June. This has continued into the July to September quarter. As Optimal dispatch is calculated as the average cost impact magnitude of using forecast data, it is dependent on both forecast accuracy and on the average cost. Since June, the lower cost of hydro generation has been the main determinant of the change (which is why this measure can be low and forecast accuracy remain in the normal range). When average costs are low, if a forecast variability results in higher priced generation being required to run, this impact on cost due to the variability makes up a larger proportion of the lower average costs which is reflected as the lower Optimal dispatch measure.

Reserves

It should be noted, the variability in the way the system responds could be a result of many factors, not just the efficiency of the System Operator actions. These factors include:

- The amount of interruptible load armed, as opposed to that offered and used as an input into RMT (and then dispatched by SPD).
- The influence of the type of generation on the amount of net free reserves available.

Observations this quarter – July to September 2022

With more hydro generation available this quarter the average AC CE risk in MW has dropped and therefore the average amount of FIR required has also decreased. NFRs have increased, which is expected for a smaller risk MW; there will also be an influence from higher demand (i.e. more system inertia) and also some benefit from the higher proportion of hydro generation.

The DC ECE risk appearing as a FIR risk setter is a result of the variability of wind output between the schedule used to determine the NFR for DC ECE and the real time scheduled requirement of HVDC transfer. If the scheduled DC transfer is larger this will exceed the NFR and require reserves procurement on the receiving island.

We continue to see, and monitor, improvements to modelling Manapouri reserves in RMT which results in net free reserves being more accurately modelled.

10 Cost of services reporting

The next cost of services reporting, for 2021/22 will be delivered to the Authority before the end of 2022.

11 Actions taken

The following table contains a full list of actions taken during Q4 2021/22 regarding the System Operator business plan, statutory objective work plan, participant survey responses and any remedial plan, as required by SOSPA 12.3 (b).

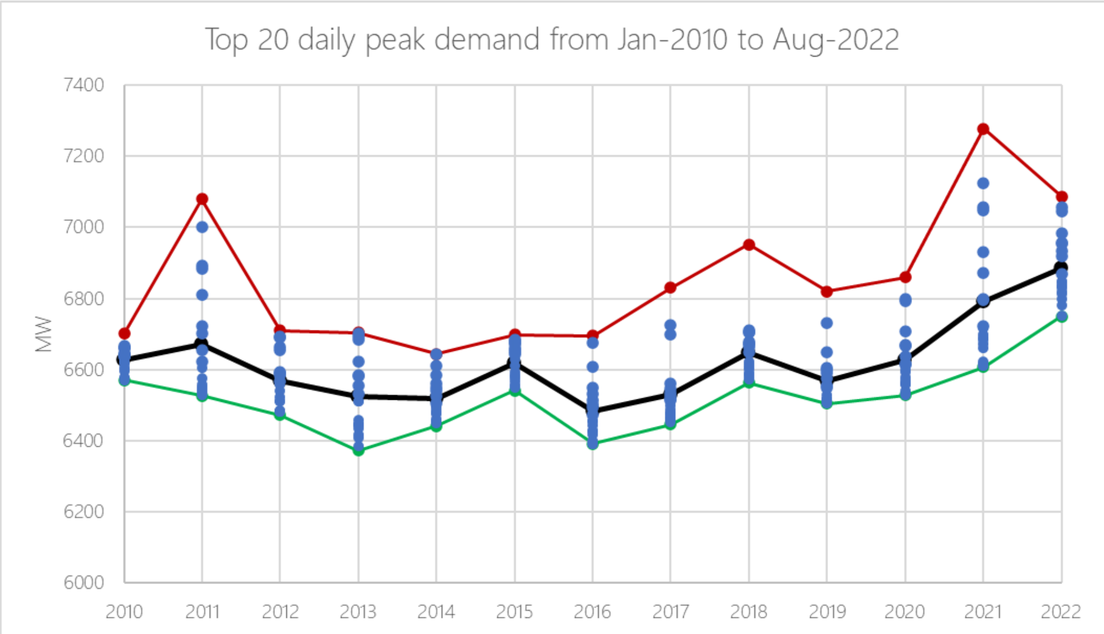
Item of interest	Actions taken
(i) To give effect to the **System Operator business plan**:	• Engage with global industry peers for future advancement *We organised a discussion with AEMO's forecasting team and coordinated knowledge sharing sessions with the UK counterparts on system operator challenges and market design opportunities for a low carbon energy system.* • Progress wind forecasts in the Real Time Market Tools *We have implemented additional data feeds from MetService regarding wind and temperature monitoring, including expert advice from a meteorologist SME. This is in addition to the improved System Operator load forecast which has seen a 30-50% forecasting improvement.*
(ii) To comply with the **statutory objective work plan**:	• Develop and agree the revised performance metrics, targets and incentive payment calculation for FY 2023/24 *During quarter 1, we have:* • *Held a workshop with the Authority staff to determine the basis on which we are collected performance metrics for the External Outcomes.*
(iii) In response to participant responses to any **participant survey**:	**Feedback from the 2021-22 survey** • "Implementing AUFLS changes is taking ages" *The System Operator and the Authority are finalising the TAS 103 statement of work for the next phase of the Extended Reserves implementation to work through the internal assessment planning and preparation work with the North Island Connected Asset Owners (CAOs) ahead of the transition from a 2-block to 4-block AUFLS.* • "Glad to see the customer portal taking shape" *The Planned Outage Coordination Process (POCP) application was successfully deployed on 12 July. Training videos are available on the Transpower YouTube channel.* *Our next launch, development of the new version of the New Zealand Generation Balance (NZGB) application, is on target to be available from early November this year.*
(iv) To comply with any **remedial plan** agreed by the parties under SOSPA 14.1	N/A – No remedial plan in place.

System performance

12 Security of supply

Hydro storage has remained high this quarter with several large inflow events impacting both islands. Average prices have dropped in response. However, storage is beginning to slowly trend downward with hydro generation remaining relatively high and South Island inflows dropping away.

During the period, the top 20 peak demand periods has again shown another year of growth. All the top 10 peak demands on record are now from 2021 and 2022. The bulk of this growth appears to be driven from the central North Island and South Island. A contribution to the growth is the removal of RCPD from the transmission pricing methodology. This has resulted in demand peaks becoming higher but shorter as less load is now being managed.



Energy

As a result of some lower average prices, baseload thermal with a start-up time of 6 hours or more has dropped out of the market. During periods of high demand and low wind generation, capacity margins have been tight, this has put pressure on the System Operator's forecasts 24 to 12 hours ahead which are generally subject to higher degree of change the further ahead they are forecasting.

We have implemented additional data feeds from MetService regarding wind and temperature monitoring, including daily expert advice from a meteorologist SME. This is in addition to the improved System Operator load forecast which has seen a 30-50% forecasting improvement.

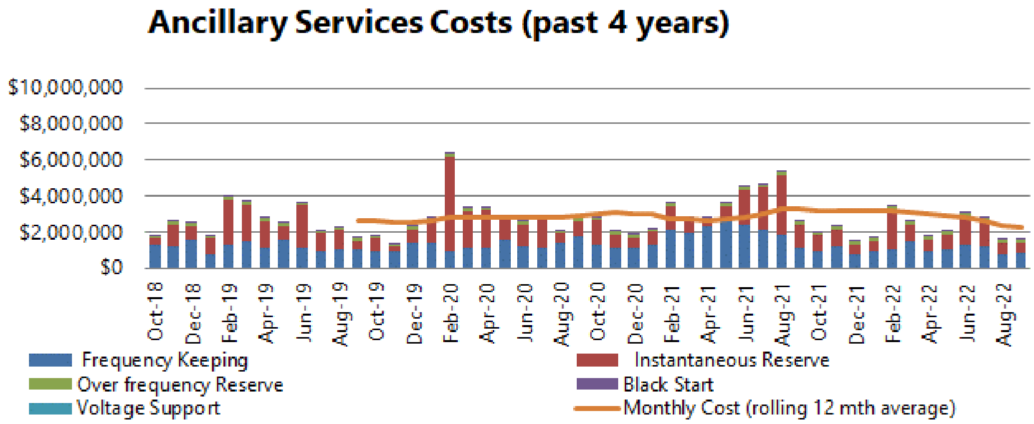
The impact of the generation mix has resulted in prices being highly volatile and moving between a sub-$10/MWh range and a $200/MWh range depending on the level of wind generation. As storage increased, we were seeing more periods of sub $10/MWh range prices.

Capacity

Section 7 of this report summarises the effect of potential shortfalls being indicated in NZGB. We have set up additional residual monitoring and reporting to ensure we can notify the market and allow participants to make informed decisions.

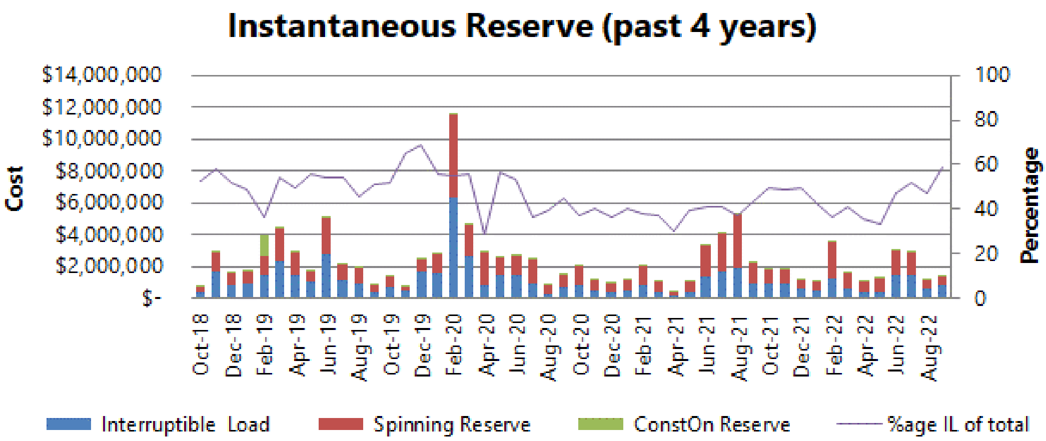
Although we expect peak demand to continue to ease up as we move through spring, we are still maintaining vigilance to provide information for any significant cold snap.

13 Ancillary services



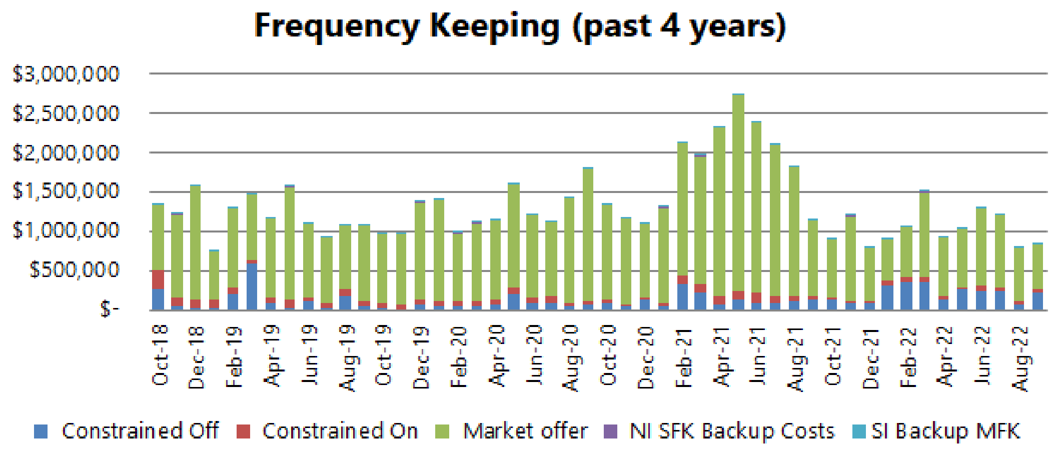
This quarter's ancillary service costs were $8.9 million, which is a 3.6% decrease compared to the previous quarter's costs of $9.3 million. This reflects lower costs for frequency keeping at $2.8 million (13.3% decrease) since last quarter. Lower spinning reserve costs were offset by higher interruptible load costs this quarter resulting in only a marginal increase in instantaneous reserve costs to $5.4 million (1.6% increase).

Higher instantaneous reserve costs in July were the result of an increased requirement for instantaneous reserves driven by colder temperatures and fewer reserve offers. Lower instantaneous reserve costs later in the quarter were the result of a reduced requirement for instantaneous reserve as the weather warms, and lower relative average prices for instantaneous reserve.



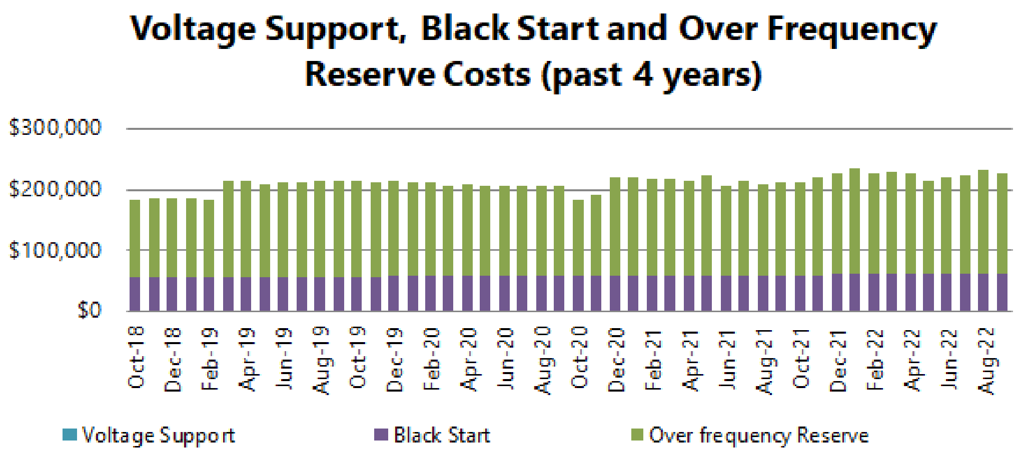
Instantaneous reserve costs were $5.4 million this quarter, which is a 2% increase on the previous quarter ($5.3 million). Interruptible load costs were higher than last quarter with an increase of $631k (28% increase), while spinning reserve costs decreased by $565k (18% decrease) and constrained on costs for instantaneous reserve increased by $17k (73% increase).

Procured quantities of North Island instantaneous reserves decreased steadily over the quarter while quantities of South Island instantaneous reserve decreased in August and recovered in September. The average price per MW for sustained instantaneous reserve also decreased significantly in August but rebounded in September in both islands. The average price per MW of fast instantaneous reserve in both the South Island and North Island decreased steadily over the quarter.



This quarter the frequency keeping costs were $2.8 million, which is a 13% decrease compared to the previous quarter's costs of $3.3 million. Constrained on costs increased by $38k (31% increase), while constrained off costs decreased by $110k (18% decrease). Market offer values decreased by $362k (15% decrease).

North Island frequency keeping costs significantly decreased this quarter to $1.3 million (22% decrease), while South Island frequency keeping costs decreased marginally to $1.5 million (4% decrease).

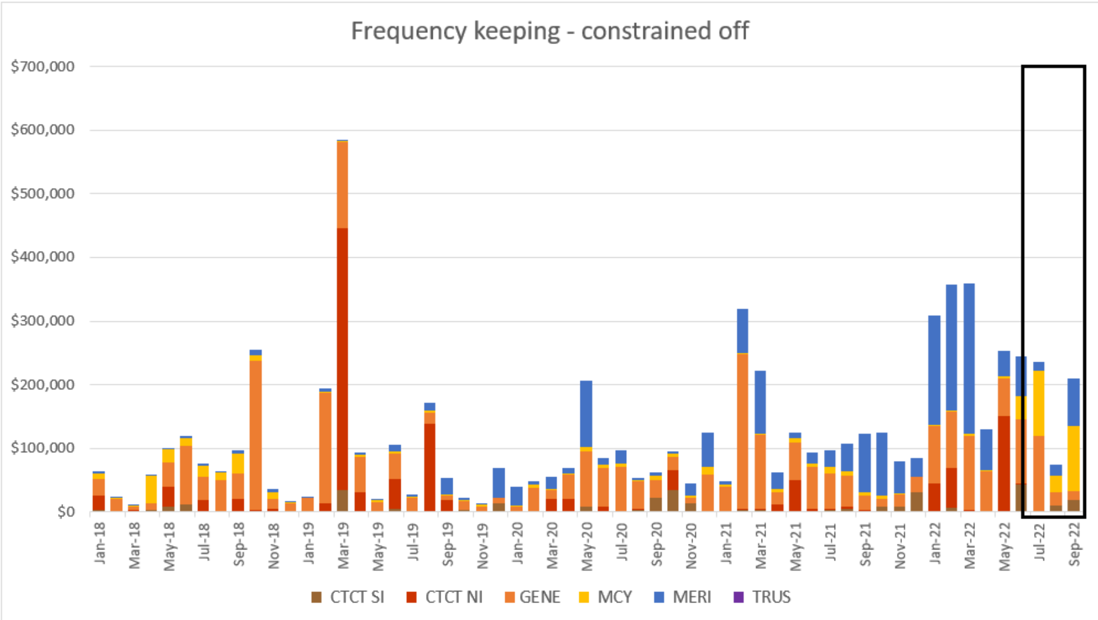


Over frequency reserve costs increased slightly this quarter to $493k (4% increase). Black start costs are unchanged since last quarter and were $62k in each month. There are no voltage support costs as there is no need to procure this ancillary service at this time.

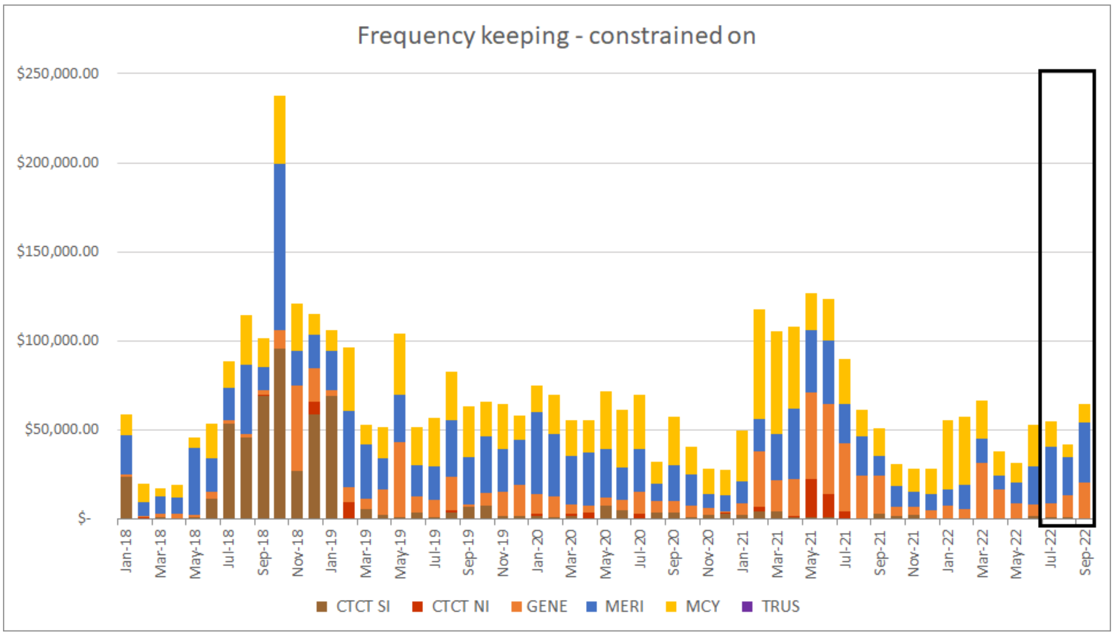
13.1 Constrained on/off costs

Note: Where there is a high payment, as opposed to in increasing/decreasing trend, it will often relate to payments over a small number of trading periods.

Frequency Keeping

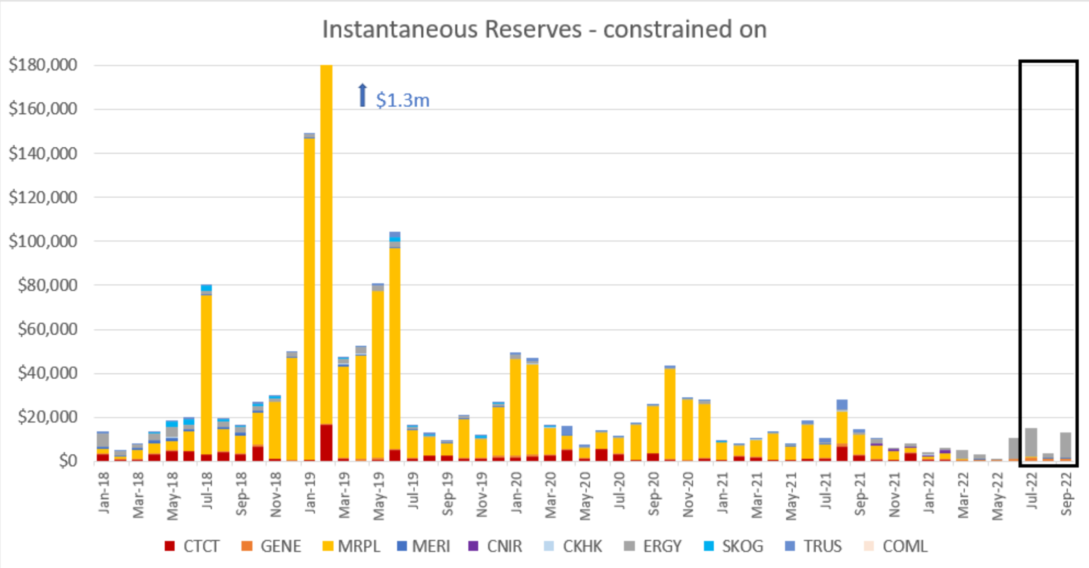


For Q1 2022/23, the frequency keeping constrained off costs decreased by 17.5% on the previous quarter to $518k. The North Island constrained off costs decreased by 8% over this period while the South Island constrained off costs decreased by 37%.



For Q1 2022/23, the frequency keeping constrained on costs increased by 30% on the previous quarter to $163k. The North Island frequency keeping constrained on costs decreased by 10% while South Island frequency keeping constrained on costs increased by 105% since the previous quarter.

Instantaneous Reserves



For Q1 2022/23, the instantaneous reserves constrained on costs increased from the previous quarter to $40k (73% increase). This is still a relatively small total and not of concern.

14 Commissioning and Testing

Generator Commissioning

We communicated our latest legal interpretation around embedded generator obligations to follow voltage support dispatches to impacted participants. Eleven embedded generators are impacted by this interpretation.

We are tracking many solar PV and wind projects which are still awaiting financial approval, as such our involvement is minimal at this stage. Should all these projects proceed it will result in a significant increase in workload for System Operator engineering teams.

The System Operator began discussions on two generator projects currently in progress: a Contact Energy geothermal unit (52 MW) near Taupō and a Mercury Energy wind farm (43 MW) near Gore.

Other projects in construction at present include Tauhara B 166 MW geothermal, Harapaki 176 MW wind, Turitea (south) 100 MW wind, and a 33 MW Battery “Rotohiko” connecting behind the Huntly GXP.

15 Operational and system events

23 June grid emergency

Ranil de Silva (PBA Consulting) completed the independent review of the System Operator's performance during the grid emergency on 23 June 2022. The PBA report notes that the new demand management processes implemented post 9 August 2021 were successfully followed to manage the generation shortfall with minimal disruption to consumers.

Under-frequency event

On 30 July 2022, an under-frequency event occurred when Huntly unit 5 tripped while at 190 MW. Following investigation, the System Operator submitted its causation report to the Authority on 16 September 2022, recommending Genesis as the causer.

17 August HVDC risk reclassification

On 17 August 2022, a fault of the Grid Owner's HVDC Pole 2 converter transformer neutral earthing resistor at Benmore required the System Operator to take action to reclassify an HVDC bi-pole tripping as a contingent event in the market system between 03:30 to 11:30. This was communicated to participants via Customer Advice Notices.

Significant incident investigations

We continue to investigate two significant events which occurred in June:

- Event 4284 - (multiple lightning strikes in June). We are preparing a more detailed report at the request of the Authority, which is due mid-October. The event was classified as a 'major' under our procedure (due to multiple contingencies), requiring a full investigation report.
- Event 4292 - (loss of supply at Hangitiki for more than 1 hour in June). We submitted a final report to the Authority, with no breaches or underperformance of the System Operator service identified. The Grid Owner is taking steps to help prevent a reoccurrence of a similar event at Hangatiki.

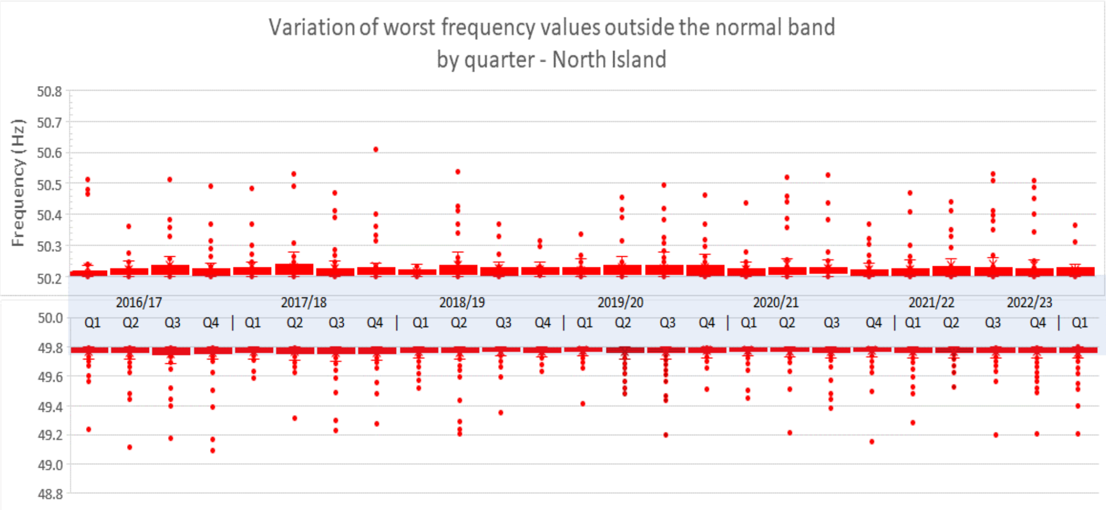
We submitted a proposal to the Authority to change the significant incident criteria to ensure we are reporting on the right level of incidents considering associated consequences.

16 Frequency fluctuations

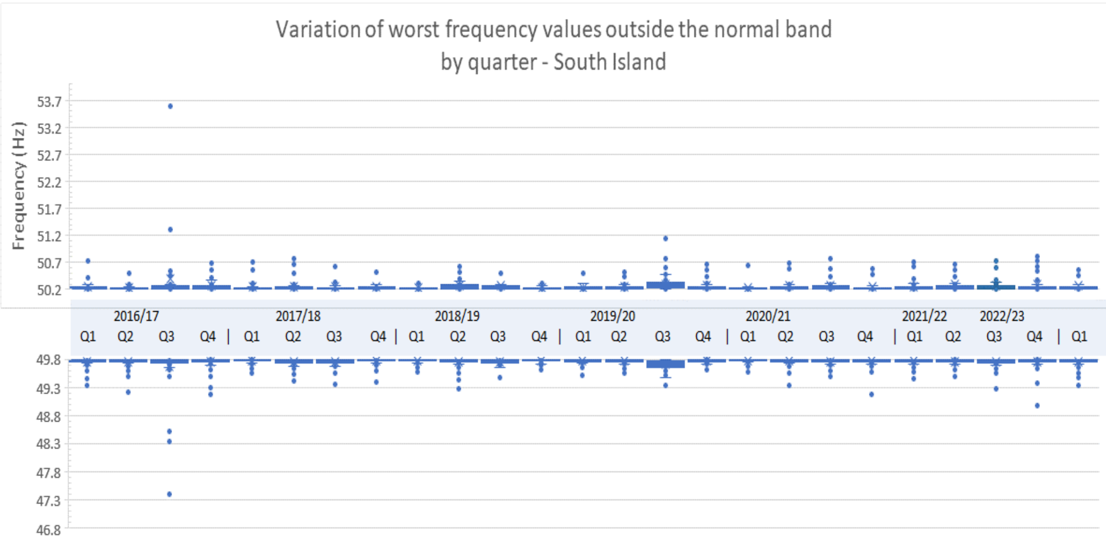
16.1 Maintain frequency in normal band (Frequency value)

The following charts show the distribution of the worst frequency excursion outside the normal band (49.8 to 50.2 Hz) by quarter since Q1 2015/16, including the reporting period.

North Island



South Island

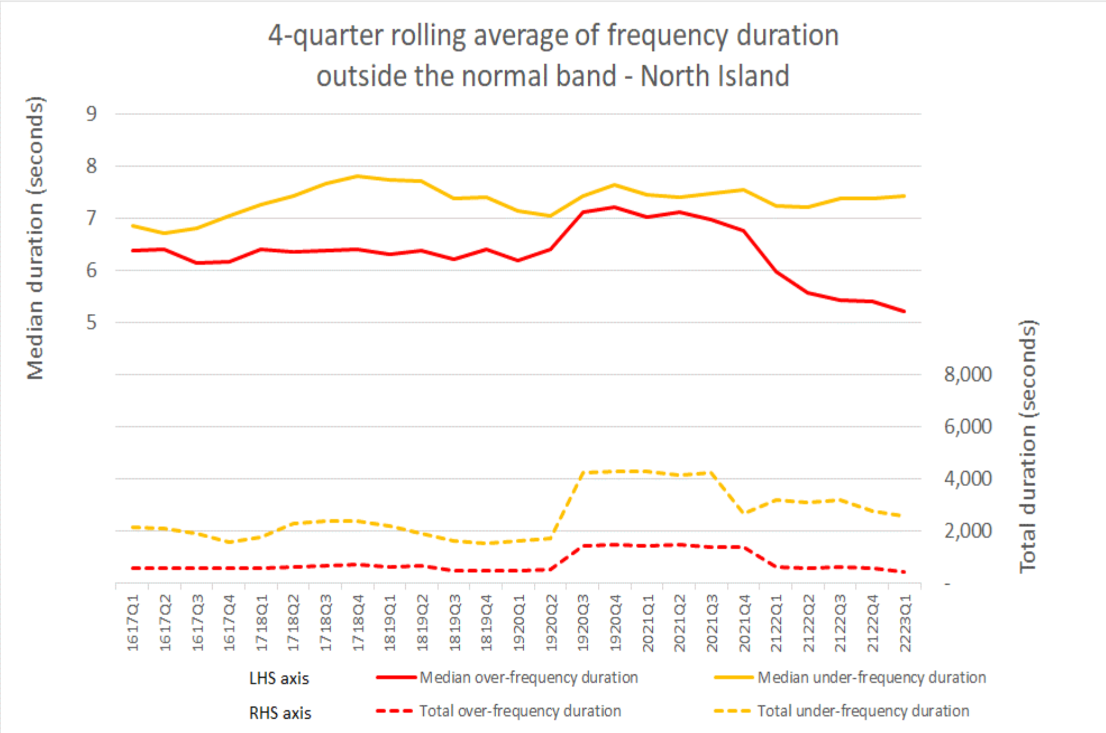


Note: These box and whisker charts show the distribution of data. The “box” represents the distribution of the middle 50% of the data, the “whiskers” indicate variability, and outliers are shown as single data points.

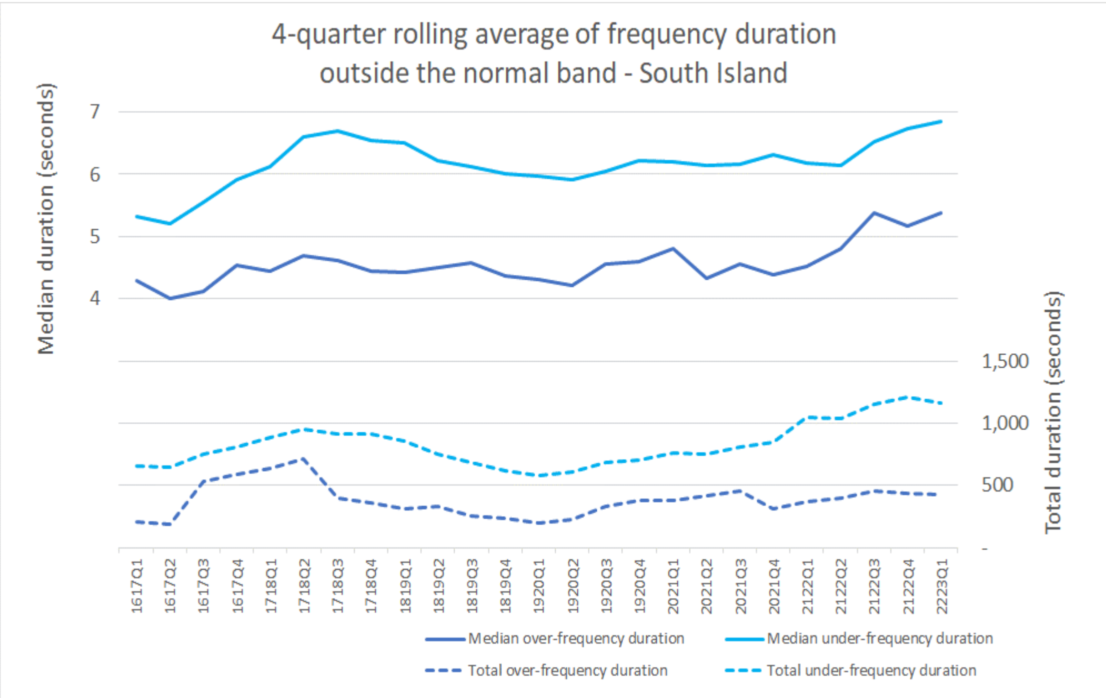
16.2 Recover quickly from a fluctuation (Time)

The following charts show the median and total duration of all the momentary fluctuations above and below the normal band for each island. The information is shown as a 4-quarter rolling average to illustrate trends in the data.

North Island



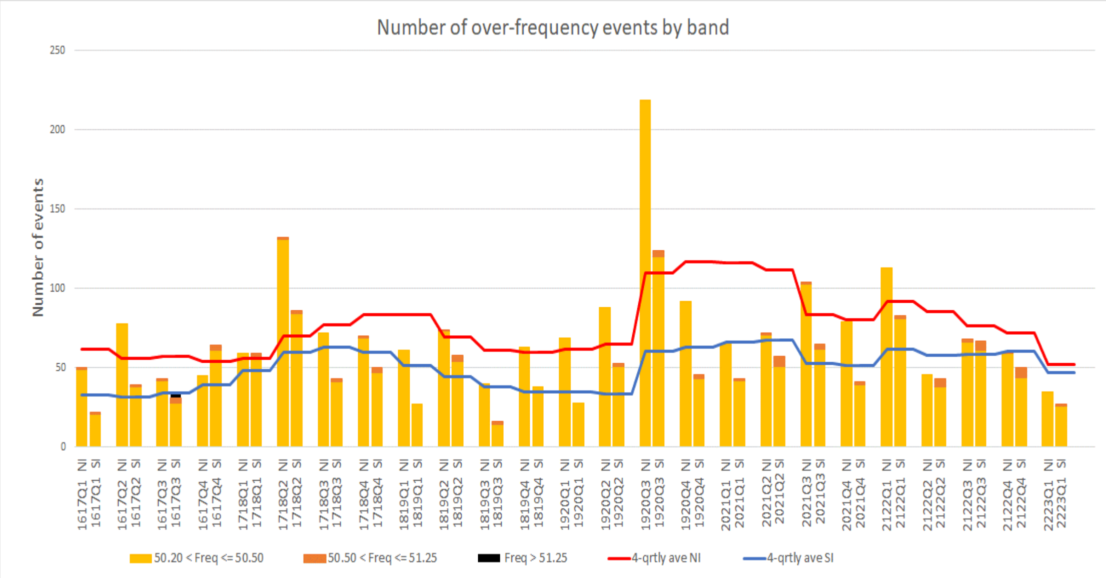
South Island



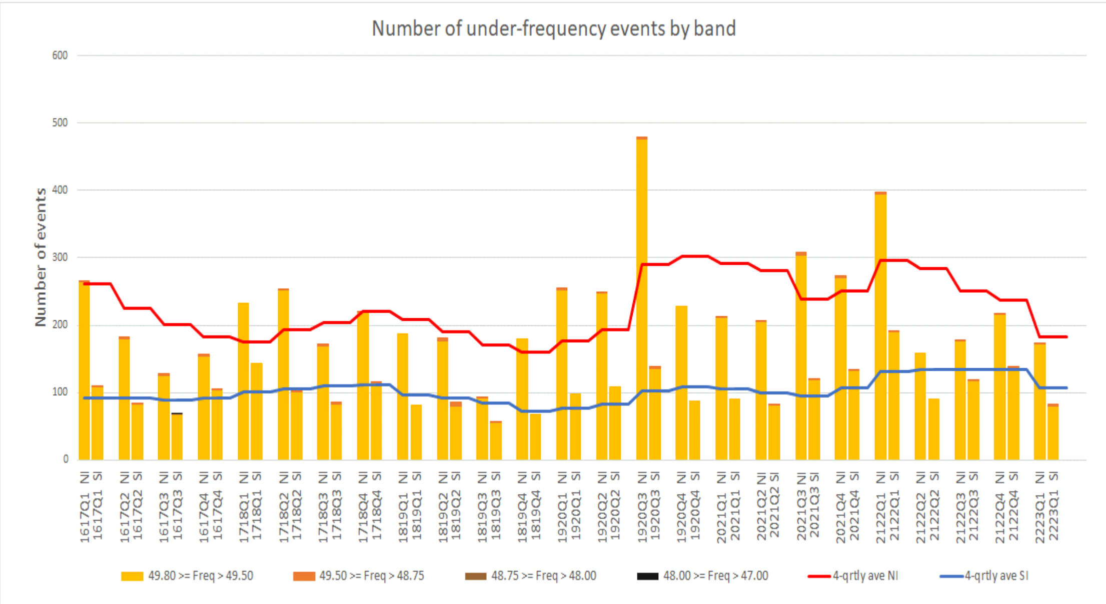
16.3 Manage frequency and limit rate of occurrences during momentary fluctuations (Number)

The following charts show the number of momentary fluctuations outside the frequency normal band, grouped by frequency band, for each quarter since Q1 2015/16. Information is shown by island, including a 4-quarter rolling average to show the prevailing trend.

Over-frequency events



Under-frequency events



16.4 Manage time error and eliminate time error once per day

There were no time error violations in the reporting period.

17 Voltage management

Grid voltages did not exceed the Code voltage ranges during the reporting period.

18 Security notices

The following table shows the number of Warning Notices, Grid Emergency Notices and Customer Advice Notices issued over the last 12 months.

Notices issued	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22
Demand Allocation Notice	-	--	--	-	-	-	-	-	-	-	-	-	-
Grid Emergency Notice	2	--	2	-	-	-	-	-	-	1	-	-	1
Warning Notice	-	--	--	-	-	-	-	-	1	-	-	-	-
Customer Advice Notice	34	9	7	5	7	9	15	14	15	28	24	25	35

19 Grid emergencies

The following table shows grid emergencies declared by the System Operator July to September 2022.

Date	Time	Summary Details	Island
03/09/22	00:12	A grid emergency was declared to allow a grid reconfiguration to assist with restoration of supply following the tripping of the 110 kV Albury – Tekapo A circuit.	S

Appendices

Appendix A: Discretion

In recent months, discretion has been reclassified to include the process to manage generators on minimum MW values overnight. As a result, the list of discretions in this report is much larger than previously recorded. There will also be further actions recorded as discretions when RTP goes live in November. We will be assessing if there is benefit in reporting these two new categories of discretion in this report as the latest information distorts any previous trends.

July (32)

Event Date and Time	Description
11/07/2022 17:32	ARG1101 BRR0 Discretion to 0MW to allow for BLN & KIK switching Last Dispatched MW: 11
13/07/2022 05:36	HLY2201 HLY5 Min: 190. Last Dispatched MW: 169.3
13/07/2022 06:00	HLY2201 HLY5 Min: 190 Last Dispatched MW: 194.79
14/07/2022 02:05	SPL forecast to be dispatched below minimum running of 160MW due to low prices. Contact confirmed they would claim 13.82a. Ran OPS case without SPL and considerably cheaper interval cost with SPL at min. 160MW versus off. Additionally, with no HLY generation SPL absorbing Mvars to control voltage. Applied optional island manual risk NI CE value of 159MW for TP 7,8,9,11 and 12.
15/07/2022 13:25	ARG1101 BRR0 Discretion applied for switching for the return of ARG_KIK_1 outage. Last Dispatched MW: 11
18/07/2022 06:46	ARG1101 BRR0 Discretion for Planned circuit outage, ARG required off for switching. Last Dispatched MW: 11
18/07/2022 21:25	Schedules from 18:00 (NRSL) and 19:00 (NRSS) had all 3 of HLY5, SPL0, and NAP0 dispatched below minimum run. All 3 traders (Contact, Mercury, and Genesis) confirmed that if dispatched as scheduled, they would be claiming Rule 13.82. North Island Optional Island Manual CE Risk of 189 applied for TP 45 to 47 18/07/22 to keep HLY 5 at its minimum of 190, and then 159 from TP48 18/7/22 to TP 15 19/07/22 to keep SPL on at 160 MW until 07:00. Note: Interval cost at 08:30 in NI with NAP on was $3052, with NAP off same period cost was $8788.
19/07/2022 21:51	Schedules from 20:00 (NRSL) and 20:30 (NRSS) had SPL0 dispatched below minimum run. Called Contact Trader who confirmed that if dispatched as scheduled, they would be claiming Rule 13.82. North Island Optional Island Manual CE Risk of 159 applied for TP 46 19/07/22 to TP14 20/07/22 to keep SPL on at 160 MW until 07:00. Note: Interval cost at 08:30 in NI with SPL on was $3804, with SPL off same period cost was $36096.
20/07/2022 09:35	MAN2201 MAN0. Last Dispatched MW: 738. Unit 4 trip dispatch required.

Event Date and Time	Description
20/07/2022 19:32	Schedules from 18:00 (NRSL) and 19:00 (NRSS) had SPL0 dispatched below minimum run. Called Contact Trader who confirmed that if dispatched as scheduled, they would be claiming Rule 13.82(a). North Island Optional Island Manual CE Risk of 159 applied for TP 46 20/07/22 to TP14 21/07/22 to keep SPL on at 160 MW until 07:00. Note: Interval cost total for TP46 - TP14 with SPL on $1,991.37, with SPL off cost $10,129.02.
21/07/2022 17:46	WHI2201 WHI0 For security of supply over the evening peak. Last Dispatched MW: 20.27.
21/07/2022 19:01	Schedules from 18:00 (NRSL) had SPL0 dispatched below minimum run. Called Contact Trader who confirmed that if dispatched as scheduled, they would be claiming Rule 13.82. North Island Optional Island Manual CE Risk of 159 applied for TP 02 22/07/22 to TP14 22/07/22 to keep SPL on at 160 MW until 07:00.
22/07/2022 15:25	ARG1101 BRR0 Discretion to 0MW for return of ARG_BLN_1 outage. Last Dispatched MW: 11
22/07/2022 20:45	Schedules from 18:00 (NRSL) had SPL0 dispatched below minimum run. Called Contact Trader who confirmed that if dispatched as scheduled, they would be claiming Rule 13.82. North Island Optional Island Manual CE Risk of 159 applied for TP 47 22/07/22 to TP14 23/07/22 to keep SPL on at 160 MW until 06:30.
23/07/2022 23:50	Schedules from 23:30 (NRSS) had SPL0 dispatched below minimum run. Called Contact Trader who confirmed that if dispatched as scheduled, they would be claiming Rule 13.82. North Island Optional Island Manual CE Risk of 159 applied for TP 01 24/07/22 to TP15 24/07/22 to keep SPL on at 160 MW until 07:00.
24/07/2022 18:37	Schedules from 18:00 (NRSL) had SPL and NAP dispatched below minimum run. Called Contact Trader who confirmed that if dispatched as scheduled, they would be claiming Rule 13.82(a). North Island Optional Island Manual CE Risk of 159 applied for TP45 24/07/22 to TP14 25/07/22 to keep SPL on at 160MW and NAP at 139MW until 07:00. Total interval cost with NAP/SPL off $53,354.63, with NAP/SPL on $1,185.63.
25/07/2022 06:57	ARG1101 BRR0 PSO for ARG_KIK Outage Last Dispatched MW: 11
25/07/2022 21:35	Schedules from 20:00 (NRSL) had SPL and NAP dispatched below minimum run. Called Contact Trader who confirmed that if dispatched as scheduled, they would be claiming Rule 13.82(a). North Island Optional Island Manual CE Risk of 159 applied from TP42 22:30 25/07/22 to TP 14 06:30 to keep SPL on at 160MW and NAP at 139MW. Total interval cost with NAP/SPL off $ 2,791.17 with NAP/SPL on $1,363.88.
25/07/2022 23:49	HLY2201 HLY5 Claimed 13.82A minimum MW capability 190MW due to resource consent. SC advised discretion applied for least cost solution. Last Dispatched MW: 159
26/07/2022 16:08	MAN2201 MAN0 Discretion applied to allow for restoration of Line 3 extended offload. Last Dispatched MW: 738

Event Date and Time	Description
26/07/2022 21:03	Schedules from 20:00 (NRSL) had HLY5 dispatched below minimum run. SC Called Genesis Trader who confirmed that if dispatched as scheduled, they would be claiming Rule 13.82(a). North Island Optional Island Manual CE Risk of 189 applied from TP46 22:30 26/07/22 to TP 00 00:00 to keep HLY5 on at min run of 190MW. HLY 5 was due off at 00:00 on 27/7/22.
27/07/2022 13:21	Optional Island Manual Risk set to 189MW for TP's 27, 29, and 29 due to a large pickup in the NI wind. SDP was dispatching HLY U5 below their minimum run level. SC called HLY Trader to find out if they would claim Rule 13.82 and they said yes. HLY U5 is required for system security.
27/07/2022 14:30	Optional Island Manual Risk set to 189MW for TP's 31, and 32 due to a large pickup in the NI wind. SDP was dispatching HLY U5 below their minimum run level. HLY U5 is required for system security.
27/07/2022 15:06	Optional Island Manual Risk set to 189MW for TP's 30, and 31 due to a large pickup in the NI wind. SDP was dispatching HLY U5 below their minimum run level. HLY U5 is required for system security.
27/07/2022 20:49	Schedules from 20:00 (NRSL) had HLY5 dispatched below minimum run TP47 & 48 and SPL below 160MW from TP48 until TP10. SC Called Genesis and Contact Traders who confirmed that if dispatched as scheduled, they would be claiming Rule 13.82(a). NAP trader called independently to advise the same. North Island Optional Island Manual CE Risk of 189 applied for TP47 & 48 27/07/22 to keep HLY5 on at min run of 190MW and 159MW for TP1 until TP1128/07 to keep SPL on at min run of 160MW.
28/07/2022 21:43	SC has applied Optional Island Manual CE Risk for 28/07/22 TP48 of 189MW to keep HLY U5 on its minimum run level, and 29/07/22 TP 1 to TP 10 of 159MW to keep SPL on their minimum run level as both are required for System Security on the AMPK. Also applied at 189MW from TP 11 to TP 14 to allow HLY U5 to reconnect on 29/07/22.
28/07/2022 21:43	SC has applied Optional Island Manual CE Risk for 28/07/22 TP48 of 189MW to keep HLY U5 on its minimum run level, and 29/07/22 TP 1 to TP 10 of 159MW to keep SPL on their minimum run level as both are required for System Security on the AMPK. Also applied at 189MW from TP 11 to TP 14 to allow HLY U5 to reconnect on 29/07/22.
29/07/2022 10:23	SC has applied Optional Island Manual CE Risk for 29/07/22 TP 21 - 24 (189MW to keep HLY U5 on at its minimum run level). NRSS had predicted issues would appear in TP 23 & 24, but just after talking to the Genesis Trader HLY U5 was dispatched below 190, so the Manual Risk was applied to TP 21 & 22 as well.
29/07/2022 10:46	SC extended Optional Island Manual CE Risk to include 29/07/22 TP 25 - 36 (189MW to keep HLY U5 on at its minimum run level) as NRSS was predicting issues in further Trading Periods.
29/07/2022 13:58	ARG1101 BRR0 Discretion applied for return of ARG_KIK_1 (was 18:30, now 14:30). Last Dispatched MW: 6
29/07/2022 19:31	SC extended Optional Island Manual CE Risk to include 29/07/22 TP 46 - 12 30/07/22 (189MW (HLY5) for 2 TP, then 159MW for the remaining to keep SPL on at its minimum run level) as NRSL was predicting issues in further Trading Periods.
30/07/2022 22:11	SC has applied Optional Island Manual CE Risk for 31/07/22 TP 1 - 15 (159MW to keep SPL on at its minimum run level).

August (67)

Event Date and Time	Description
1/08/2022 3:20	SC called Genesis trader as wind was 100MW above forecast bring HLY 5 below the minimum running range. Genesis confirmed if dispatched below their minimum running range they would claim rule 13.82a. SC has applied NI Optional Island Manual CE Risk for 01/08/22 TP 31-33 (189 MW) to keep HLY5 on at its minimum run level. HLY 5 is required for security.
1/08/2022 10:57	NRSL schedules had SPL below minimum run level (HLY U5 offline). Contact Trader confirmed that if dispatched as scheduled, they would be claiming Rule 13.82(a). SC has applied NI Optional Island Manual CE Risk from 01/08 23:30 - 02/08 05:30 to schedule SPL at its minimum run level (159MW). Keeping SPL on is the least cost solution as per clause 13.57
2/08/2022 0:30	NRSS schedules had HLY U5 below minimum run level (190MW). Genesis Trader confirmed that if dispatched as scheduled, they would be claiming Rule 13.82(a). SC has applied NI Optional Island Manual CE Risk from 02/08 TP29 - TP31 to schedule HLY U5 at its minimum run level (189MW). Keeping HLY U5 on is the least cost solution as per clause 13.57
2/08/2022 9:39	Schedules from 20:00 (NRSL) had NAP dispatched below minimum run. SC Called MRGTrader who confirmed that if dispatched as scheduled, they would be claiming Rule 13.82(a). North Island Optional Island Manual CE Risk of 139 applied from TP01 00:00 03/08/22 toTP12 05:30 to keep NAP on at min run of 140MW. NAP held on for security, Interval cost for 02/08/22 08:30 are NAP in: $1906.27, NAP off: $7416.07
2/08/2022 18:04	HLY2201 HLY5 Min : 190 Genesis Trader claimed Rule 13.82(a). Keeping U5 at its minimum run level of 190MW is the least cost dispatch solution. Last Dispatched Mw: 139
3/08/2022 9:55	Schedules from 20:00 (NRSL) had NAP dispatched below minimum run. SC Called MRGTrader who confirmed that if dispatched as scheduled, they would be claiming Rule 13.82(a). North Island Optional Island Manual CE Risk of 139 applied from TP01 00:00 04/08/22 toTP10 04:30 to keep NAP on at min run of 140MW. NAP held on for security,
3/08/2022 12:02	NRSL schedules had NAP below minimum run level (140MW). Mercury Trader confirmed that if dispatched as scheduled, they would be claiming Rule 13.82(a). SC has applied NI Optional Island Manual CE Risk from 04/08 00:00 - 05:30 to schedule NAP at its minimum run level (139MW). Keeping NAP on is the least cost solution as per clause 13.57
3/08/2022 21:55	RPO2201 RPO0 Max : 0 Due to RPO_WRK_1 and RPO_TNG_1 planned outages Last Dispatched Mw: 65
4/08/2022 0:30	RPO2201 RPO0 Discretion Clause 13.70, Part 13 ENR Max : 0 Start: 04-Aug-2022 12:30 End: 04-Aug-2022 13:00 Notes: Due to RPO_WRK_1 and RPO_TNG_1 planned outages Last Dispatched Mw: 0

Event Date and Time	Description
4/08/2022 8:45	Schedules from 20:00 (NRSL) had HLY5 and NAP dispatched below minimum run. SC Called Traders who confirmed that if dispatched as scheduled, they would be claiming Rule 13.82(a). North Island Optional Island Manual CE Risk of 139 applied for TP46 (22:30) and 138 for TP47 through to TP13 05/08/22 06:30 to keep NAP on at min run of 139MW.
5/08/2022 6:26	Schedules from 20:00 (NRSL) had HLY5 and NAP dispatched below minimum run. SC Called Traders who confirmed that if dispatched as scheduled, they would be claiming Rule 13.82(a). North Island Optional Island Manual CE Risk of 189 applied for TP46 (22:30) for HLY5 minimum, and 138 for TP47 through to TP13 05/08/22 06:30 to keep NAP on at min run of 139MW.
6/08/2022 7:19	Schedules from 18:00 (NRSL) had HLY5 and NAP dispatched below minimum run. Traders confirmed that if dispatched as scheduled, they would be claiming Rule 13.82(a). North Island Optional Island Manual CE Risk of 139 applied for TP46 (22:30) and 138 for TP47 through to TP13 06/08/22 06:30 to keep NAP on at min run of 139MW.
6/08/2022 11:49	NAP2202 NTM0 Min : 85 Claimed Rule 13.82a, plant and personnel safety. Minimum run is 85MW. Current dispatch is 85.4MW. NTM has offers of 86MW at $0.01 in current TP. dropping to 85MW offered at 00:00, then back up to 86MW at 00:30. Trader initially claimed minimum run was 85MW. After a check of offers for today and tomorrow, EC called Mercury trader back and confirmed that the minimum run was 85MW. Last Dispatched Mw: 85.37
7/08/2022 9:14	Schedules from 21:00 (NRSS) had NAP dispatched below minimum run. Trader confirmed that if dispatched as scheduled, they would be claiming Rule 13.82 2 (a). North Island Optional Island Manual CE Risk of 139 applied for TP48 (23:30) to TP12 08/08/22 05:30 to keep NAP on at min run of 140MW.
7/08/2022 11:04	HLY2201 HLY5 Max : 0 Last Dispatched Mw: 138.28Due to 13.82 (2) a Plant security. Discretioned to zero due to not being required for system security amd coming off next trading period, I also gave the option of meeting dispatch within their station
7/08/2022 14:00	KAW0111 TAM0 Max : 0 13.82(2A) claimed. Not required for system security. Last Dispatched Mw: 6.08
7/08/2022 18:02	RTD at 06:00 had HLY U5 dispatched below its minimum run level of 182 MW as it was starting up, due to reserve pricing. HLY U5 generation was needed over the morning peak so North Island Optional Island Manual CE Risk of 181 was applied for TP13 to allow HLY U5 to continue its start-up and operate at (or above) it's minimum run level of 182 MW.
8/08/2022 9:50	Schedules from 21:00 (NRSS) had NAP dispatched below minimum run. Trader confirmed that if dispatched as scheduled, they would be claiming Rule 13.82 2 (a). North Island Optional Island Manual CE Risk of 139 applied for TP47 to TP10 to keep NAP on at min run of 140MW.
8/08/2022 10:42	HLY2201 HLY5 Max : 0 Last Dispatched Mw: 148.7 Due to 13.82 (2) a Plant security. Discretioned to zero due to not being required for system security and coming off next trading period, I also gave the option of meeting dispatch within their station

Event Date and Time	Description
8/08/2022 18:00	RTD at 06:00 had HLY U5 dispatched below its minimum run level of 182 MW as it was starting up, due to reserve pricing. HLY U5 generation was needed over the morning peak so North Island Optional Island Manual CE Risk of 181 was applied for TP13 to allow HLY U5 to continue its start-up and operate at (or above) it's minimum run level of 182 MW.
11/08/2022 20:10	WHI2201 WHI0 Min : 10 Constrained on for security due to low residual situation. Last Dispatched Mw: 26
11/08/2022 20:20	WHI2201 WHI0 Min : 10 Constrained for security to manage low residual situation. Last Dispatched Mw: 10.54
14/08/2022 13:41	Schedules from 01:30 (NRSS) had NAP dispatched below minimum run. Trader confirmed that if dispatched as scheduled, they would be claiming Rule 13.82 2 (a). North Island Optional Island Manual CE Risk of 139 applied for TP5 to TP8 to keep NAP on at min run of 140MW.
16/08/2022 13:57	Schedules from 01:30 (NRSS) had NAP dispatched below minimum run. Trader confirmed that if dispatched as scheduled, they would be claiming Rule 13.82 2 (a). North Island Optional Island Manual CE Risk of 139 applied for TP5 to TP8 to keep NAP on at min run of 140MW as lowest cost
17/08/2022 9:50	Schedules from 21:00 (NRSS) had HLY 5 dispatched below minimum run of 190 MW for TP's 46 & 47 (22:30 and 23:00). Genesis trader confirmed that if dispatched as scheduled, they would be claiming Rule 13.82 2 (a). OPS case run to confirm that having HLY_5 on provided least cost solution to the market. North Island Optional Island Manual CE Risk of 189 applied for TP's 46 and 47.
17/08/2022 10:35	20:00 NRSL had NAP dispatched below minimum run of 139 MW for TP's 4 to 11 (01:30 and 05:30). MRG trader confirmed that if dispatched as scheduled, they would be claiming Rule 13.82 2 (a). OPS case run to confirm that having NAP on provided least cost solution to the market. North Island Optional Island Manual CE Risk of 138 applied for TP's 4 to 11.
18/08/2022 7:25	18:00 NRSL schedule had HLY 5 dispatched below minimum run of 190 MW for TP's 47 on 18th Aug, and TP13 on 19t. Genesis trader confirmed that if dispatched as scheduled, they would be claiming Rule 13.82 2 (a). OPS case run to confirm that having HLY_5 on provided least cost solution to the market (e.g., looking at just the 08:00TP with HLY5 and NAP off interval cost was $67k vs $5.5k with them on). North Island Optional Island Manual CE Risk of 189 applied for relevant TPs.
18/08/2022 7:29	18:00 NRSL had NAP dispatched below minimum run of 139 MW from 00:00-06:00 MRG trader confirmed that if dispatched as scheduled, they would be claiming Rule 13.82 2 (a). OPS case run to confirm that having NAP on provided least cost solution to the market. North Island Optional Island Manual CE Risk of 138 applied for relevant TPs.
18/08/2022 10:27	Genesis trader advised HLY5 had been dispatched below its rough running range of 190MW in the 22.20RTD and claimed Rule 13.82(a). NRSS schedules had been clear, and the unit was scheduled at 215MW during 22:00TP. SC entered 189MW in the Optional Island Manual Risk in Reserve Requirements for both the 22:00 and 22:30TPs, a Load and Solve RMT was completed, and unit re-dispatched to 190MW at 22:26. 22:30 RTD dispatched unit back up to 205MW as per NRSS schedule.

Event Date and Time	Description
19/08/2022 6:20	18:00 NRSL had NAP dispatched below minimum run of 139 MW from 23:30-06:00 MRG trader confirmed that if dispatched as scheduled, they would be claiming Rule 13.82 2 (a). OPS case run to confirm that having NAP on provided least cost solution to the market. North Island Optional Island Manual CE Risk of 138 applied for relevant TPs.
19/08/2022 11:15	HLY2201 HLY5 Min : 182 Last Dispatched Mw: 186.14Claiming Code rule 13.8.2.2 a due to plant safety. minimum run 182MWPlant was left on for the remainder of the trading period to ensure least cost solution
19/08/2022 13:27	ROX2201 ROX0 Min : 60 Trader claimed 13.82A. Discussed previously with Security Coordinator. ROX discretioned onto their minimum for least cost solution for the market. Last Dispatched Mw: 56.32
19/08/2022 13:28	Contract Trader/Operator called EC to advise they would be claiming an exemption to Rule 13.82 2 (a) if ROX 2201 is dispatched below its min (two units U3 & U5 at 60MW) as indicated in the the forward schedules from 01:30. SC asked Trader/Operator to clarify and the reason for a min of two units on ROX2201 at 60MW. The explanation was the ROX station (2201 & 1101) has only one local service at the moment as is supplied by U3 (min 30MW and fixed MVAR output) and U5 is required for local voltage support thus no 2201 generation also means no 1101 generation. Note ROX 2201 prices at 0.01c and reaming ROX generation on 1101 (40MW) at 0.00c. 2 hour turn around if station is shutdown. OPS case run to assess impact of security and interval cost with no ROX generation which reported the price change would be an increase of $373. Decision made to discretion ROX 2201 to min 60MW if and when required due to the least cost solution for the market.
19/08/2022 18:17	Genesis trader claimed Rule 13.82 (a), HLY U5 dispatched to 139MW, below its minimum run level of 190MW. SC has applied NI Optional Island Manual CE Risk from 20/08 06:00 - 06:30 to schedule HLY U5 at its minimum run level (189MW). Keeping HLY U5 on is the least cost solution as per clause 13.57
20/08/2022 6:47	18:00 NRSL had NAP dispatched below minimum run of 139 MW from 23:00-06:30 MRG trader confirmed that if dispatched as scheduled, they would be claiming Rule 13.82 2 (a). OPS case run to confirm that having NAP on provided least cost solution to the market. North Island Optional Island Manual CE Risk of 138 applied for relevant TPs.
20/08/2022 10:39	20:00 NRSL had HLY5 dispatched below minimum run of 190MW for 23:00 TP Genesis trader confirmed that if dispatched as scheduled, they would be claiming Rule 13.82 2 (a). OPS case run to confirm that having HLY5 on provided least cost solution to the market. North Island Optional Island Manual CE Risk of 189 applied for this TP.
21/08/2022 8:27	20:00 NRSL had HLY5 dispatched below minimum run of 190MW for 23:00 TP Genesis trader confirmed that if dispatched as scheduled, they would be claiming Rule 13.82 2 (a). OPS case run to confirm that having HLY5 on provided least cost solution to the market. North Island Optional Island Manual CE Risk of 189 applied for this TP. NAP also dispatched below 140 MW (min run) from 23:00 to 06:00. Mercury trader claimed rule 13.82a for these periods if dispatched to scheduled values. 139MW applied as NI optional AC CE risk from 23:30 to 06:00. 189 also applied for 06:00 TP as HLY5 below min run.

Event Date and Time	Description
21/08/2022 22:39	Discretion applied to ROX 2201 to 80 MW.
22/08/2022 20:27	ROX Generation scheduled off at 22:30 from 101MW. Contact operator advised if U6 (providing LocalService) was shut down, the machines couldn't be restarted until tech on site to restore LS. SC decided it was prudent to keep 220 kV generation on for 22:30 period asf ROX generation was scheduled back up to 101 MW through to AMPK.
22/08/2022 22:11	ROX2201 ROX0 For security (tomorrow ampk), if shutdown will lose local service and be unable to start again. Last Dispatched MW: 80
22/08/2022 22:15	NAP2201 NAP0 For optimal solution, below minimum run, claimed 13.82(a), cheaper to keep on than shutdown. Last Dispatched MW: 140
22/08/2022 22:50	NAP2202 NTM0 For optimal solution, below minimum run, claimed 13.82(a), cheaper to keep on than shutdown Last Dispatched MW: 84.71
22/08/2022 22:51	HLY2201 HLY5 For optimal solution, below minimum run, claimed 13.82(a), cheaper to keep on than shutdown. Last Dispatched MW: 189
22/08/2022 23:19	20:00 NAP dispatched below 140 MW (min run) from 23:00 to 06:00. Mercury trader claimed rule 13.82a for these periods if dispatched to scheduled values. 139MW applied as NI optional AC CE risk from 23:00 to 06:00. 24-48 hours to come back online, required for system security.
23/08/2022 18:54	HLY2201 HLY5 Dispatched to minimum run to allow adequate cool down for 1 trading period as claimed by trader, along with rule 13.82(a) for plant safety. Last Dispatched MW: 135
23/08/2022 23:07	HLY2201 HLY5 Trader claimed 13.82a as dispatched to 157MW, min is 190MW. Discretioned on for security for evening peak. Last Dispatched MW: 157.35
24/08/2022 13:35	HLY2201 HLY5 Trader claimed 13.82a as dispatched to 157MW, min is 190MW. Discretioned on for security for evening peak. Last Dispatched MW: 157.35
24/08/2022 13:36	NRSL schedules had NAP scheduled below minimum run level (140MW). Mercury Trader confirmed that if dispatched as scheduled, they would be claiming Rule 13.82(a). SC has applied NI Optional Island Manual CE Risk from 23/08 22:30 - 24/08 06:30 to schedule NAP at its minimum run level (139MW). Keeping NAP on is the least cost solution as per clause 13.57
24/08/2022 16:57	HLY2201 HLY5 Trader claimed 13.82a as dispatched to 135MW, min is 182MW. Discretioned to zero as no security reason to keep the unit on. Last Dispatched MW: 135

Event Date and Time	Description
24/08/2022 23:06	ARI1102 ARI0 Applied for switching duration for KIN_TRK_1 outage to avoid ARI runback triggering, and for security reasons as WTO stations are all at max output and unable to compensate (max 160MW ARI N & S generation total as ARI_CB48 to be closed) Last Dispatched MW: 111
25/08/2022 7:32	At 15:00 HLY5 dispatched 128.06MW, at 15:30 HLY5 dispatched to 128.06MW, at 16:00 HLY5 dispatched 148.24MW. Genesis called and claimed 13.82A for the trading periods due to running in their rough running range. At present with HLY5 on, interval cost for 15:00 is $79.75 and at 17:30 HLY 5 on interval cost is $1090.88. OPS case ran with HLY 5 off. Interval cost for 15:00 is $169.55. Interval cost for 17:30 is $11328.99. HLY 5 is also required for security over evening peak. 189MW applied as NI optional AC CE risk from 15:00 to 16:30.
25/08/2022 7:32	ARI1101 ARI0 Applied for switching duration for KIN_TRK_1 outage to avoid ARI runback triggering, and for security reasons as WTO stations are all at max output and unable to compensate (max 160MW ARI N & S generation total as ARI_CB48 to be closed) Last Dispatched MW: 81
25/08/2022 14:15	MRPL trader rang concerning NAP dispatched below 136MW for 15:00 and 15:30 trading periods in NRSS. Claimed 13.82a as plant physically unable to meet dispatch. SC had analysed HLY5 for same trading periods and applied manual NI CE risk to keep them on for economic and security reasons
25/08/2022 14:25	ARI1101 ARI0 Applied for switching duration for KIN_TRK_1 outage to avoid ARI runback triggering, and for security reasons heading into the evening peak (max 160MW ARI N & S generation total as ARI_CB48 to be opened) Last Dispatched MW: 81
25/08/2022 17:00	ARI1102 ARI0 Applied for switching duration for KIN_TRK_1 outage to avoid ARI runback triggering, and for security reasons as WTO stations are all at max output and unable to compensate (max 160MW ARI N & S generation total as ARI_CB48 to be opened) Last Dispatched MW: 111
25/08/2022 17:01	NRSL schedules had NAP scheduled below minimum run level (140MW). Mercury Trader confirmed that if dispatched as scheduled, they would be claiming Rule 13.82(a). SC has applied NI Optional Island Manual CE Risk from 24/08 00:30 - 24/08 06:00 to schedule NAP at its minimum run level (139MW). Keeping NAP on is the least cost solution as per clause 13.57
25/08/2022 22:08	HLY2201 HLY5 Trader claimed 13.82a as dispatched to 135MW, min is 182MW. Discretioned to zero as no security reason to keep the unit on, unit was scheduled to come off at 23:30. Last Dispatched MW: 137.11
25/08/2022 23:17	SFD2201 SFD21 Discretioned on for security reasons over the evening peak Last Dispatched MW: 43.28
26/08/2022 17:30	NAP scheduled to be dispatched below 138 MW (min run) from 00:00 to 06:00. Mercury traders confirm they will claim rule 13.82(2) for these periods if dispatched to scheduled values, and that should NAP be dispatched off it will take them 48 hours to return. 137 MW applied as NI optional AC CE risk from 00:00 to 06:00.
27/08/2022 21:18	TKA0111 TKA1 ABY_TKA circuit tripped, TKA generation confirmed tripped off. Last Dispatched MW: 23

Event Date and Time	Description
28/08/2022 6:06	NAP scheduled to be dispatched below 140 MW (min run) from 01:30 to 06:00. Mercury traders confirm they will claim rule 13.82(2) for these periods if dispatched to scheduled values, and that should NAP be dispatched off it will take them 48 hours to return. 139 MW applied as NI optional AC CE risk from 01:30 to 06:00.
28/08/2022 18:51	HLY 5 scheduled to be dispatched below 190 MW (min run) from 23:00 to 23:30. Genisis trader confirm they will claim rule 13.82(2) for these periods if dispatched to scheduled values. NI REf price rises by $10/MW with HLY 5 off.189 MW applied as NI optional AC CE risk from 23:00 to 23:30. HLY 5 required for peak security, energy, and reactive reserve.
29/08/2022 18:45	NAP scheduled to be dispatched below 140 MW (min run) from 00:00 (29 Aug) to 05:30. Mercury trader confirm they will claim rule 13.82(2) for these periods if dispatched to scheduled values, and that should NAP be dispatched off it will take them 48 hours to return. NI REF price increases by approx. $4 per MW if NAP was to come off. 139 MW applied as NI optional AC CE risk from 00:00 (29 Aug) to 05:30.
29/08/2022 19:03	HLY 5 scheduled to be dispatched below 190 MW (min run) from 23:00 to 23:30. Genisis trader confirm they will claim rule 13.82(2) for these periods if dispatched to scheduled values. 189 MW applied as NI optional AC CE risk from 23:00 to 23:30. HLY 5 required for peak security, energy, and reactive reserve.
30/08/2022 20:23	NAP scheduled to be dispatched below 140 MW (min run) from 00:00 (29 Aug) to 05:30. Mercury trader confirm they will claim rule 13.82(2) for these periods if dispatched to scheduled values, and that should NAP be dispatched off it will take them 48 hours to return. NI REF price increases by approx. $4 per MW if NAP was to come off. 139 MW applied as NI optional AC CE risk from 00:00 (29 Aug) to 05:30.
30/08/2022 21:14	HLY 5 scheduled to be dispatched below 190 MW (min run) from 23:00 to 23:30. Genisis trader confirm they will claim rule 13.82(2) for these periods if dispatched to scheduled values. 189 MW applied as NI optional AC CE risk from 23:00 to 23:30. HLY 5 required for peak security, energy, and reactive reserve.
31/08/2022 20:39	NI optional AC CE Risk of 189 also applied for 05:30 and 06:00 TP's 01 Sep for same reasons as above."

September (47)

Event Date and Time	Description
1/09/2022 4:24	NAP scheduled to be dispatched below 139 MW (min run) from 23:00 (01 Sep) to 05:30 (2 Sept). Mercury trader confirm they will claim rule 13.82(2)a for these periods if dispatched to scheduled values, and that should NAP be dispatched off it will take them 48 to 72 hours to return due to staffing issues .139 MW has been applied to NI optional AC CE risk from 23:00 (1 Sep) to 06:30 (2 Sept).WIth NAP on

Event Date and Time	Description
	the Interval cost at 08:00 2/09 is $1926, with NAP off the Interval cost is $6687. At 08:30 02/09 with NAP on the Interval cost $1190, with NAP off the Interval cost is $3060. NAP also provides Voltage support overnight and OFA arming.
1/09/2022 9:02	HLY5 scheduled to be dispatched below 190 MW (min run) for TP47. Genesis trader confirm they will claim rule 13.82(2)a for these periods if dispatched to scheduled values. 189 MW applied as NI optional AC CE risk for TP47.
1/09/2022 17:38	HLY5 scheduled to be dispatched below 190 MW (min run) for TP13. Genesis trader confirm they will claim rule 13.82(2)a for these periods if dispatched to scheduled values. 189 MW applied as NI optional AC CE risk for TP13.
1/09/2022 18:32	Genesis trader claimed rule 13.82(2)a for TP 14. 189 MW applied as NI optional AC CE risk for TP14. Was dispatched below 189MW due to sudden increase of wind on the half hour, was scheduled 250MW.
2/09/2022 8:17	NAP scheduled to be dispatched below 140 MW (min run) from 23:00 to 06:00. Mercury trader confirm they will claim rule 13.82(2)a for these periods if dispatched to scheduled values, and that should NAP be dispatched off it will take them 48 hours to return. HLY 5 scheduled off at 23:30. 139 MW applied as NI optional AC CE risk from 23:30 to 06:00.
2/09/2022 8:26	HLY5 scheduled to be dispatched below 190 MW (min run) for TP46. Genesis trader confirm they will claim rule 13.82(2)a for these periods if dispatched to scheduled values. 189 MW applied as NI optional AC CE risk for TP46.
2/09/2022 11:47	TKA0111 TKA1 ABY_TKA cct tripped. Last Dispatched MW: 14
2/09/2022 17:00	HLY5 scheduled to be dispatched below 190 MW (min run) for TP14. Genesis trader confirm they will claim rule 13.82(2)a for these periods if dispatched to scheduled values. 189 MW applied as NI optional AC CE risk for TP14.
3/09/2022 7:18	HLY5 scheduled to be dispatched below 190 MW (min run) for TP47 before it is scheduled to come off in TP48. Genesis trader confirms they will claim rule 13.82(2)(a) for these periods if dispatched to scheduled values, and also confirms that they plan to adjust their offer to come off 1TP earlier.
3/09/2022 7:18	NAP scheduled to be dispatched below 140 MW (min run) from 23:00 to 06:30. Mercury trader confirm they will claim rule 13.82(2)(a) for these periods if dispatched to scheduled values, and that should NAP be dispatched off it will take them 48 hours to return . HLY 5 scheduled off at 23:30. 139 MW applied as NI optional AC CE risk from 23:00 to 06:30.
3/09/2022 8:13	HLY5 scheduled to be dispatched below 190 MW (min run) for TP46, despite changing their offer to come off 1TP earlier (was TP48, now TP47). OPS case shows no effective difference in interval cost in TP46. 189 MW applied as NI optional AC CE risk for TP46.
3/09/2022 10:00	ROX Generation scheduled to 2MW at 22:30 from 129MW, then back up to 213MW at 23:00, then off at 23:30, before settling ~200MW for remainder of the night. Contact operator advised if U6 (providing LocalService via the 220kV) was shut down, the machines couldn't be restarted until tech on site to restore LS, and further advised while station is off potentially unable to operate anything at the station including sluice gates. Operator advised if dispatched below 60MW he would claim Rule 13.82(2)(a). SC decided it was prudent to keep

Event Date and Time	Description
	220 kV generation on for 22:30 and 23:30TPs, and instructed EC to apply a minimum discretion on ROX220kV to 60MW (2 m/c so providing N-1 to the station) from 22:30-00:00.
3/09/2022 10:09	ROX2201 ROX0 Min : 60 ROX Generation scheduled to 2MW at 22:30 from 129MW, then back up to 213MW at 23:00, then off at 23:30, before settling ~200MW for remainder of the night. Contact operator advised if U6 (providing LocalService via the 220kV) was shut down, the machines couldn't be restarted until tech on site to restore LS, and further advised while station is off potentially unable to operate anything at the station including sluice gates. Operator advised if dispatched below 60MW he would claim Rule 13.82(2)(a). SC decided it was prudent to keep 220 kV generation on for 22:30 and 23:30TPs, and instructed EC to apply a minimum discretion on ROX220kV to 60MW (2 machines so providing N-1 to the station) from 22:30-00:00. Last Dispatched MW: 80
4/09/2022 7:53	HLY5 scheduled to be dispatched below 190 MW (min run) for TP46 before it is scheduled to come off in TP47. Genesis trader confirms they will claim rule 13.82(2)(a) for this if dispatched to scheduled. 189 MW applied as NI optional AC CE risk for TP 46
4/09/2022 7:53	NAP scheduled to be dispatched below 140 MW (min run) from 23:00 to 06:30. Mercury trader confirm they will claim rule 13.82(2)(a) for these periods if dispatched to scheduled values, and that should NAP be dispatched off it will take them 48 hours to return. 139 MW applied as NI optional AC CE risk from 23:00 to 06:30.
4/09/2022 10:09	ROX 220 Generation scheduled to 13.59MW at 23:30 from 80MW, then back up to 80MW at 00:00. Contact operator advised if U6 (providing Local Service via the 220kV and min of 40MW) was shut down, the machines could not be restarted for an entire week, and further advised while station is off potentially unable to operate anything at the station including spill and sluice gates to manage flooding conditions. Operator advised if dispatched below 80MW he would claim Rule 13.82(2)(a). as they require x1 ROX 220 unit (min 40MW) for station service and a second ROX 220 unit (min 40MW) to reduce risk of trip of the first unit if we encounter a system disturbance. SC decided for security reasons to keep ROX 220 generation on due to concerns around site safety of dispatched off and instructed EC to apply a minimum discretion on ROX220kV to 80MW 2 m/c so providing N-1 to the station.
4/09/2022 19:58	WHI2201 WHI0 Min 18MW not dispatched, see next disc to 10MW. Last Dispatched MW: 18.08
4/09/2022 19:58	WHI2201 WHI0 Min 10MW for morning peak security of supply. Last Dispatched MW: 18.08
4/09/2022 20:09	TUI1101 PRI0 Max : 35 For planned outage where the constraint did not bind Last Dispatched MW: 44
4/09/2022 20:09	TUI1101 TUI0 Max : 47 For planned outage where the constraint did not bind Last Dispatched MW: 57.4
4/09/2022 20:10	TUI1101 KTW0 Max : 27 For planned outage where the constraint did not bind. Last Dispatched MW: 32.5
5/09/2022 9:03	NAP scheduled to be dispatched below 140 MW (min run) from 22:30 to 06:30. Mercury trader confirm they will claim rule 13.82(2)(a) for these periods if dispatched to scheduled values, and that should NAP be dispatched off it will take them 48 hours to return. 139 MW applied as NI optional AC CE risk from 22:00 to 06:30.

Event Date and Time	Description
5/09/2022 9:38	HLY5 scheduled to be dispatched below 190 MW (min run) for TP46 before it is scheduled to come off in TP47. Genesis trader confirms they will claim rule 13.82(2)(a) for this if dispatched to scheduled. 189 MW applied as NI optional AC CE risk for TP 46
6/09/2022 1:42	SI HZ keeper changed manually from WTR to CLU at 18:30 through to 19:30 to maximise MW available at top of evening peak. Potential 30MW gain due to CTRL MAX / MW Difference at WTR.
6/09/2022 5:56	WHI2201 WHI0 Min : 20 Contact to start two machines on minimum load to ensure they will be available to ramp up if there is low residual energy. Last Dispatched MW: 0
6/09/2022 6:00	WHI2201 WHI0 Min : 40 Contact to start two machines on minimum load to ensure they will be available to ramp up if there is low residual energy. Last Dispatched MW: 20
6/09/2022 6:05	WHI2201 WHI0 Min : 20 Contact to start two machines on minimum load to ensure they will be available to ramp up if there is low residual energy. Last Dispatched MW: 20
6/09/2022 6:06	WHI2201 WHI0 Min : 40 Contact to start two machines on minimum load to ensure they will be available to ramp up if there is low residual energy. Last Dispatched MW: 20
6/09/2022 6:15	WHI2201 WHI0 Last Dispatched MW: 42.75
6/09/2022 6:15	WHI2201 WHI0 Last Dispatched MW: 42.75
6/09/2022 6:28	JRD1101 JRD0 Min : 76 Required for PMPK Last Dispatched MW: 76.03
6/09/2022 6:47	WHI2201 WHI0 Last Dispatched MW: 90.84
6/09/2022 6:47	WHI2201 WHI0 Last Dispatched MW: 90.84
6/09/2022 19:02	WHI2201 WHI0 Min : 10 Discretion applied to bring WHI unit on early to prepare for low residual situation at 07:30. Last Dispatched MW: 4.55
7/09/2022 6:40	WHI2201 WHI0 Min : 10 Marginal plant, have just connected. May be required later in TP and 10MW is their minimum run. Last Dispatched MW: 18.48
7/09/2022 23:59	KOE1101 NGB0 Max : 0 NGB tripped 1 min prior to half hour solve. awaiting bonafide claim Last Dispatched MW: 33
14/09/2022 18:40	SI HZ keeper excluded from WTR to CLU at 07:30 through to 08:30 to maximise MW available at top of evening peak. Potential 30MW gain due to CTRL MAX / MW Difference at WTR.
14/09/2022 18:57	WHI2201 WHI0 Min : 40 Required for system security for the morning peak - 2x units connected and running. Last Dispatched MW: 0
14/09/2022 19:00	WHI2201 WHI0 Min : 20 Required for system security for the morning peak. Last Dispatched MW: 0
14/09/2022 19:03	WHI2201 WHI0 Min : 40 Required for system security for the morning peak. Last Dispatched MW: 20

Event Date and Time	Description
14/09/2022 19:25	WHI2201 WHI0 Min : 60 Required for system security for the morning peak. Last Dispatched MW: 51.61
14/09/2022 20:04	WHI2201 WHI0 Min : 40 Required for system security for the morning peak. Last Dispatched MW: 60
20/09/2022 22:08	TKA0111 TKA1 Max : 0 ABY TKA 1 Trip Last Dispatched MW: 16
21/09/2022 17:46	KPA1101 KPI1 Max : 0 LOC due to OPK_KPI_SFD2 tripping. Last Dispatched MW: 1
22/09/2022 18:00	MAT1101 ANI0 Max : 0 MAT 92 tripped. ANI unable to generate. Last Dispatched MW: 25
25/09/2022 4:23	NAP scheduled to be dispatched below 136 MW (min run) from 02:00 (26 Sep) to 06:00 (2 Sept). Mercury trader confirm they will claim rule 13.82(2)a for these periods if dispatched to scheduled values, and that should NAP be dispatched off it will take them 48 to 72 hours to return, more likely 72 hours due to issues with restarting at present .135 MW has been applied to NI optional AC CE risk from 20:00 (25 Sep) to 07:00 (26 Sept). NAP is also required for voltage support and OFA.
27/09/2022 6:04	SFD2201 SFD21 Max : 0 Contact called claiming 13.82A minimum running range is 7MW, dispatched to 2MW. Not required for security Last Dispatched MW: 1.25

Appendix B: Dispatch Accuracy Dashboards

Energy

Same quarter in 2021/22

This quarter 2022/23

			July	August	September	October	November	December	2022 January	February	March	April	May	June	July	August	September
FK within 1% of band limit	% of time frequency keepers spend near to or exceeding their regulation limits indicates the need to redispatch.	NI	3.28%	3.01%	2.66%	2.54%	2.64%	3.47%	2.68%	3.54%	2.58%	3.16%	2.58%	2.42%	2.47%	2.52%	2.67%
		SI	3.31%	2.92%	2.66%	2.55%	2.59%	3.48%	2.72%	3.55%	2.31%	3.13%	2.57%	2.44%	2.50%	2.53%	2.67%
FK outside of band limit	% of time frequency keepers spend outside their regulation limits	NI	0.01%	0.02%	0.04%	0.02%	0.02%	0.01%	0.01%	0.08%	0.05%	0.03%	0.04%	0.01%	0.03%	0.01%	0.04%
		SI	0.00%	0.02%	0.01%	0.00%	0.02%	0.00%	0.00%	0.03%	0.01%	0.01%	0.01%	0.00%	0.01%	0.00%	0.01%
HVDC modulation beyond 30MW band	% of minutes where the maximum HVDC modulation exceeds 30MW away from its dispatch setpoint. This indicates greater variability in the system, but can also indicate the need for redispatch.		15.05%	11.78%	10.93%	8.11%	10.05%	9.09%	9.09%	10.37%	7.38%	8.38%	9.13%	10.89%	13.55%	11.16%	10.78%
Constrained on energy- Total	Total Monthly Generation	MWh	4,038,786	3,857,499	3,628,916	3,553,128	3,411,254	3,381,156	3,423,033	3,102,676	3,300,548	3,303,156	3,612,262	3,598,421	4,004,136	3,954,180	3,681,478
	Total constrained on - All sources	MWh	25,760	25,586	33,595	26,561	24,861	37,425	27,518	25,195	25,071	17,302	21,182	24,421	32,151	30,377	29,256
		% of all generation	0.64%	0.66%	0.93%	0.75%	0.73%	1.11%	0.80%	0.81%	0.76%	0.52%	0.59%	0.68%	0.80%	0.77%	0.79%
Constrained on energy ($) - Frequency keeping	Total constrained on $ due to frequency keeping (within band is attributable to SO)	$ Constrained On Energy	678,100	418,027	387,985	232,948	269,822	428,273	264,827	351,930	1,048,490	1,034,695	273,109	765,655	721,155	434,805	579,448
		$ Grid Constrained On Energy	90,143	61,541	50,707	31,140	28,176	28,196	41,297	57,475	66,726	38,151	31,680	53,162	54,655	42,003	64,386
Optimal Dispatch (%)	Compares the average impact of a perfect foresight case against dispatch solutions. Indicates impact of wind offer, load forecast and PSD accuracy.	%	94.240%	93.790%	92.500%	91.500%	92.270%	92.480%	93.910%	92.050%	94.100%	95.730%	94.830%	91.160%	90.310%	92.020%	88.960%
Dispatch load accuracy error (%)	Average absolute difference between forecast generation (load plus losses, including PSD) and actual generation relative to the average actual	%	99.580%	99.620%	99.580%	99.620%	99.590%	99.570%	99.600%	99.570%	99.600%	99.610%	99.600%	99.620%	99.610%	99.620%	99.610%
Wind offer accuracy (%)	Average absolute difference between persistence wind offer (based on 5mins prior) and the actual wind output relative to the average wind	%	97.360%	97.540%	97.730%	97.340%	97.710%	97.550%	97.410%	97.340%	97.260%	97.440%	97.420%	97.510%	97.510%	97.310%	97.090%

Scale for measures: Variation of up to 0.25 std devs from standard | ... up to 1 std dev from standard | ... up to 2 std devs from standard | ... over 2 std devs from standard

Scale for metric: 1 | 2 | 3

NOTE 1: Commentary on the current quarter's data is included in section 9.1 of this report

Understanding the energy dashboard

The purpose of this dashboard is to identify trends and outliers for measures that represent overall industry performance in energy dispatch. The System Operator actions are only one of the influences in this performance. Three of the measures in which the System Operator has some influence in the performance are converted into a metric.

Measures selected

We have selected measures that cover the following key areas of dispatch performance:

- When operator discretion is required
- Variations in frequency
- When generators are required to be constrained on/off to meet the dispatch objective
- Variation in output and inputs to the Optimum dispatch tool, which compares what happened in real time to what would have happened if there had been perfect foresight

Colour scale

The dashboard uses coloured shading to make it easy to highlight interesting cells or ranges of cells and emphasise unusual values. In this case we have used a colour scale from green (good performance) through to orange (outliers). Each of the cells sits on a colour gradient within this scale.

The colour scales used in the dashboard reflect performance against a standard. A standard that represents good performance has been applied to each of the measures. Variance from this standard identifies outliers which we comment on in section 9.1 of the report. The current standard is the average of the data since January 2019.

Variation of up to 0.25 std devs from standard	... up to 1 std dev from standard	... up to 2 std devs from standard	... over 2 std devs from standard

[1]

Metric[2]

The measures that contribute towards the metric are:

- FK outside of band limit [3]
- Constrained on energy- Total
- Optimal Dispatch (%)

There are three stages to calculating the metric

1. **Determine a standard**
   This is based on what represents good performance
2. **Rate the comparison on a scale of 1 to 3**
   The monthly performance is compared to the standard against a predefined scale. There are two scales used in this calculation - FK outside of the band limit and Constrained on energy - Total; and Optimal Dispatch (%). These are shown in the tables below: [4]

Score	Outcome	Measure is:
3	Good performance	Up to 0.25 std devs above the standard
2	OK performance	Between 0.25 and 1 std dev above the standard
1	Weak performance	Over 1 std devs above the standard

Score	Outcome	Optimal dispatch is:
3	Good performance	Up to 0.25 std devs below the standard
2	OK performance	Between 0.25 and 1 std dev below the standard
1	Weak performance	Over 1 std devs below the standard

3. **Calculate an overall metric score**
   The overall metric is the average of the three individual scores.

Example:

			Month	Standard
FK outside of band limit	% of time frequency keepers spend outside their regulation limits	NI	0.20%	0.08%
		SI	0.02%	0.01%
Constrained on energy- Total	Total constrained on - All sources	MWh	23,649	28,417
		% of all generation	0.59%	0.80%
Optimal Dispatch (%)	Compares the average impact of a perfect foresight case against dispatch solutions. Indicates impact of wind offer, load forecast and PSD accuracy.	%	93.2%	92.37%
	Metric calculation rows	FK outside band	2	
		Constrained on	3	
		Optimal Dispatch	3	
Dispatch accuracy %	Metric out of 3 (3 is best possible result)		2.7	

FK outside of band limit = (0.2+ 0.02)/2 = 1.1 -> 2 (as a result of the distribution for this measure)
Constrained on energy- Total = 0.59 -> 3 (as a result of the distribution for this measure)
Optimal Dispatch (%) = 93.20% -> 3 (as a result of the distribution for this measure)
Overall metric = (2+3+3)/3 = **2.7**

[1] Since last quarterly report we have changed the way in which we measure variation, to make it in terms of standard deviations (instead of percentage variations) for both the conditional formula shading and the metric calculation
[2] This metric is for analysis purposes and is not part of the performance metrics report to the Authority
[3] Last quarterly report used the measure FK within 5% of band limit, we have updated this as variation outside of band limit was felt to be more meaningful
[4] The score was changed during the year from a five point (1-5) to a three point (1-3) scale.

Reserves

Same quarter in 2021/22

This quarter 2022/23

			2021						2022								
			July	August	September	October	November	December	January	February	March	April	May	June	July	August	September
FIR procured vs Risk	NI+SI Fast Instantanous Reserve (FIR) procured divided by the estimate of FIR risk. A greater proportion suggests over procurement of reserves in the relevant island. Monthly average	ACCE	0.70	0.71	0.66	0.68	0.72	0.64	0.74	0.82	0.76	0.73	0.79	0.70	0.59	0.47	0.48
		DCCE	0.88	0.87	0.84	0.79	0.74	0.78	NIL	0.88	NIL	NIL	NIL	NIL	0.54	0.58	0.45
FIR procured (MW)	Average FIR MW procured per trading period		251	257	203	198	204	166	217	268	244	246	256	213	176	113	107
SIR procured (MW)	Average SIR MW procured per trading period		372	386	313	303	301	263	307	357	337	343	339	318	306	255	239
FIR procured ($)	Total monthly cost ($) of FIR procured		1,803,527	3,083,309	1,224,614	867,796	850,026	604,671	648,275	2,668,483	1,026,829	773,471	1,016,826	1,289,642	654,500	350,087	60,030
SIR procured ($)	Total monthly cost ($) of SIR procured		2,216,743	2,198,285	1,038,035	973,776	953,870	498,131	425,975	819,488	565,559	272,183	275,921	1,676,320	2,203,944	858,185	1,286,853
Net free reserves (NFRs)	Average national Net free reserves (NFRs) for a trading period where the risk type is binding, averaged over a month	AC	124	116	115	107	106	103	97	88	96	106	90	111	140	152	145
		DC	77	95	88	96	112	99	NIL	82	NIL	NIL	NIL	NIL	115.55	126.76	124.29
Reserve sharing	Average percentage of FIR procured that is shared between islands. FIR shared NI+SI / FIR MW Procured NI+SI (Average per trading		36%	26%	37%	35%	52%	42%	51%	33%	42%	46%	43%	47%	50%	57%	64%
IL vs Spinning Reserve	Percentage of IR procured as interuptable load.	FIR	39%	33%	34%	36%	32%	32%	34%	35%	34%	28%	27%	34%	36%	25%	24%
		SIR	38%	36%	37%	38%	35%	35%	39%	36%	34%	27%	26%	36%	43%	37%	36%
Risk setter	Most common risk setter (highest number of trading periods)	NI	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE+15	HLY5CE	HLY5CE
		SI	ManualCE;OtherIslandCE	OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE
Proportion of time risk setter	Proportion of time each type of risk was FIR risk setter	ACCE	99.80%	78.18%	95.13%	87.77%	95.56%	94.83%	99.93%	89.43%	100.00%	100.00%	100.00%	100.00%	99.26%	96.10%	94.99%
		DCCE	0.20%	22.09%	2.50%	10.35%	2.78%	1.08%	0.00%	10.57%	0.00%	0.00%	0.00%	0.00%	0.34%	3.09%	2.78%
		DCECE	0.00%	0.14%	2.36%	1.88%	1.67%	4.10%	0.07%	0.07%	0.00%	0.00%	0.00%	0.00%	0.40%	0.81%	2.23%
Average MW risk when risk setter	Average risk MW for each risk type when they are the FIR risk setter	ACCE	356	329	305	283	287	247	294	313	319	337	326	305	300	237	225
		DCCE	393	394	367	319	323	281	0	420	0	0	0	0	253	302	228
		DCECE	0	159	50	106	62	240	149	0	0	0	0	0	39	59	45
Reserve accuracy metric	**FIR procured vs Risk (ACCE)**		**70%**	**71%**	**66%**	**68%**	**72%**	**64%**	**74%**	**82%**	**76%**	**73%**	**79%**	**70%**	**59%**	**47%**	**48%**

Understanding the reserves dashboard

The purpose of this dashboard is to provide greater visibility of statistics on fast instantaneous reserve (FIR) and sustained instantaneous reserves (SIR) which enable us to look at trends in reserve procurement.

Measures selected

We have selected a number of measures that identify trends in instantaneous reserves procurement. The one which we believe is the key one to focus on is:

> Monthly average of [FIR MW procured as a percentage of the FIR risk] per trading period (%)
> across the whole of New Zealand[5] for AC contingent events (ACCE)

This is because it reports on System Operator efficiency in procuring the lowest quantity of FIR to ensure system stability following an event. It also provides an insight into the output of the key System Operator tool – RMT. We consider this provides useful information and trends that can be analysed further. Note, this measure is focused on FIR quantities rather than costs which are largely a result of reserve offer prices than optimal procurement.

Colour scale

The dashboard uses coloured shading to highlight patterns in the data. In this case the shading identifies the variability of the results in the dashboard; it does not compare the results against a standard.

The variation in the shading should not be interpreted as good/bad – but used to identify where there is variation.

All results for a measure may be extremely good, but if there is any variation, the shading simply shows the most desirable values in darker green and the least desirable values in orange; colours from pale green, through pale orange illustrate the relative values between these two extreme points.

The blue shading is used for measures where the concept of least desirable and most desirable does not exist.

[5] The introduction of the national IR market has resulted in reserves being shared across the islands.