Monthly System Operator and system performance report

for the Electricity Authority

July 2022

Report Purpose

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

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

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System Operator performance

1 Highlights this month

- The NZGB application is currently forecasting potential N-1-G shortfalls in August and September. The System Operator has recommended 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.
- Prices are highly volatile and are moving between a sub-$10/MWh range and a $200/MWh range depending on the level of wind generation. The low prices are resulting in baseload thermal with a start-up time of 6 hours or more beginning to drop out of the market when load is low and wind generation is high, and come back into the market over periods of forecast high peak demand and low wind generation. This is putting pressure on the System Operators 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 expert advice from a meteorologist to provide further insight for the forecast.
- Hydro storage increased to 110% of average for the time of the year due to a large single inflow event impacting both islands on 20 July.
- On 30 July 2022, an under-frequency event occurred when Huntly unit 5 tripped while at 190 MW. The System Operator is investigating the event and recommend a causer to the Authority.
- An independent consultant's report on 23 June 2022 grid emergency noted that the new demand management processes implemented by the System Operator post-9 August 2021 were successfully followed to manage the generation shortfall with minimal disruption to consumers.
- We are working through voltage management implications associated with bringing back into service the Brownhill–Pakarunga 2 cable.
- The completion of RTP Phase 3 development was delayed by two weeks to 15 July, as a result of COVID-19 related illness, and an increase in workload due to technical complexity. The schedule was re-assessed early in August and it was determined that the current deadline will still be met.
- Final findings in our Operational Excellence engagement are being drawn up. Recommendation streams will include governance, assurance, process, training and capability, change and change capability, and resourcing.
- The new Planned Outage Coordination Process (POCP) application was successfully deployed in the Operations Customer Portal on 12 July. We have started developing the new New Zealand Generation Balance (NZGB) application, which is expected to be available through the Customer Portal from early November this year.
- The first Business Audit of the year - Defects and Enhancements Audit – has been scoped and will start in mid-August.
- We are entering the next stage of the KPI refresh programme, which will roll out performance reporting to the Authority for the System Operator functions. The final outcome of this work be a new set of reporting metrics and associated incentives mechanism agreed with the Authority for 2023/24

2 Customers and other relationships

System Operator Industry Forums

Our industry forums have been 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. The latest forum in early August was a useful vehicle to communicate the effect of the cold snap 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.

Energy Systems Integration Group (ESIG)

One of our principal market advisors attended the ESIG webinar on wind and solar power forecast management. The presenter was from Electric Reliability Council of Texas (ERCOT) who are facing challenges with integrating increasing volumes of wind and solar to their energy only market. There were several worthwhile takeaways to feed into our internal thinking and industry discussions on intermittent generation forecasting

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.

3 Risk & Assurance

COVID-19

A risk assessment was carried out regarding access to the control rooms. This is in line with the organisational risk matrix, and has enabled us to reinstate external visits to the control rooms. Visitors are asked to undertake a RAT test and wear masks; entry is limited to no more than three at a time and for a maximum time of 15 minutes.

Risk Management Framework

A paper outlining the System Operator's risk management framework was tabled at the 8 August 2022 Electricity Authority System Operator Committee meeting and well-received.

Business assurance audits

The 2022/2023 Audit Plan is underway with the Defects and Enhancements Audit scoped and scheduled to start mid-August. The four remaining System Operator Audits will be executed according to the plan.

4 Compliance

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

9 August event

We continue to work with the Authority to finalise documentation for the Rulings Panel and will confirm submission date(s) with the Rulings Panel in August.

5 Impartiality of Transpower roles

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

System Operator Open Conflict of Interest Issues		
ID	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
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
42	**Mercury KPO upgrade:** The Power Systems Engineer assigned to manage the KPO upgrade previously worked at Mercury. The employee will provide input into the commissioning/testing documentation and will prepare the final compliance documentation for SO sign-off. Controls have been implemented, including management oversight and sign-off of all commissioning/testing documentation.	Power Systems Engineering Assurance Manager

6 Project updates

6.1 Market design and service enhancement project updates

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

Future Security and Resilience (FSR) Programme

We continue to support the Authority in developing a plan to execute the next steps of the FSR programme. These steps focus on reviewing and updating Part 8 of the Code (common quality) to account for changes in technology and location of generation assets.

Real-Time Pricing (RTP)

The completion of Phase 3 development was delayed by two weeks to 15 July, as a result of COVID-19 related illness, and an increase in workload due to technical complexity. We had previously delayed the stand-alone dispatch (SAD) component to complete at the end of July, however with the delay incurred and an increase in complexity, the end date for this piece of work is being reviewed as it did not complete by the end of July as previously reported. Testing and prep-work is underway to move into the staging environment for initial deployment testing. The challenges of illness across the team and resource turnover in the testing team is continuing and this is being mitigated where possible. Planning for the change, both technical deployment and business change, is in progress. Based on the above impacts, it was determined that the current deadline will still be met. The Authority has deferred any request for the expected additional budget until the actual expenditure is forecast to exceed a threshold closer to the currently agreed budget.

Operational Excellence

We are working with an external consultancy and are currently preparing the final findings for this engagement which will be presented as a forward-looking roadmap with recommended initiatives outlined. Findings are the result of several weeks of work, during which input has been sought from across operational teams determining the Operations group current and desired future states. The final programme output seeks to guide our current state towards our future state.

Recommendation streams will include governance, assurance, process, training and capability, change and change capability, and resourcing. Some of these opportunities will map to existing initiatives in our capital investment. This work is set to conclude in August.

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.

We have started developing the new NZ Generation Balance (NZGB) application, which is expected to be available through the Customer Portal from early November this year.

KPI Refresh Programme

We are entering the next stage of the KPI refresh programme, which will roll out performance reporting to the Authority for the System Operator functions. On 11 August, the Authority System Operator Committee agreed on the high-level areas they would like to be reported in the portfolio of metrics and incentives. The System Operator will now work with Authority staff to collaboratively develop a refreshed set of performance metrics by the end of the calendar year. The final outcome of this work be a new set of reporting metrics and associated incentives mechanism agreed with the Authority for 2023/24.

7 Technical advisory hours and services

Technical advisory hours and a summary of all technical advisory services (TAS) to which those hours related (SOSPA 12.3 (d) refers) will be provided in the next quarterly report.

8 Outage planning and coordination

Outage planning – near real time

Whilst outage numbers have been lower than spring and summer, we have had more short notice changes, owing to availability of resources (likely to be sickness related.)

New Zealand Generation Balance (NZGB) analysis

The NZGB application is currently forecasting potential N-1-G shortfalls in August and September. In the second half of August, the days of higher risk are due to the amount of generation that is on outage when combined with assumptions of worst-case load forecasting (from August 2021) and low wind generation.

The System Operator has published monthly NZGB reports covering these potential shortfalls as well as two NZGB assessments and Customer Advice Notices (CANs) specifically covering August. 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. In addition to this, the General Manager Operations has also reached to senior management at generation companies to further emphasise what the System Operator’s recommendations and expectations are.

Since early July, there has been some positive response from the industry and the generation balance has improved significantly as outages were shifted around. There are periods, however, of higher risk which still exist in August and September and require further response from the industry. The System Operator published the August NZGB Monthly Report in early August as well an assessment and CAN covering the potential shortfalls in September. The System Operator continues to monitor these periods and share this information with the industry to avoid shortfalls in real-time.

9 Power systems investigations and reporting

No items to report.

10 Performance metrics and monitoring

System Operator performance against the performance metrics for the financial year as required by SOSPA 12.3 (a) will be provided in the next quarterly report.

11 Cost-of-services reporting

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

12 Actions taken

A full list of actions taken regarding the System Operator business plan, statutory objective work plan, participant survey responses and any remedial plan, as required by SOSPA 12.3 (b) will be provided in the next quarterly report.

System performance

13 Security of supply

Storage began the month around the 90% of average for the time of year and closed the month around 110% of average for the time of year. This increase was due to a large single inflow event impacting both islands on 20 July.

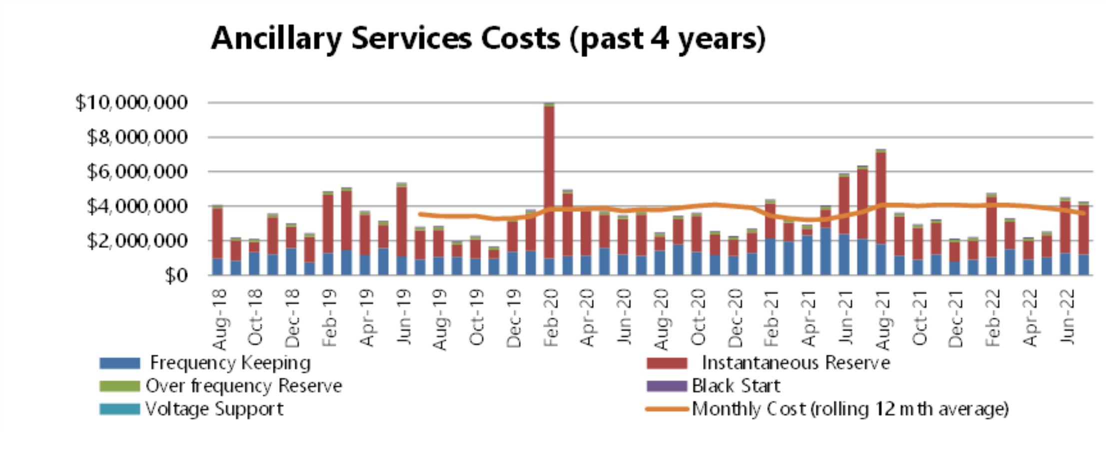
National demand decreased to 848 GWh (10 GWh lower than the previous week) however, South Island demand was up on last week. Demand peaked at 6,880 MW on Monday 25 July at 5:30pm during a cold day, which is among the top ten all-time peaks. Monday's total demand was 10 GWh, 8% more than any other day last week.

The contribution of renewables to the generation mix dropped slightly this week to 88%. Hydro generation dropped slightly to 62% of the generation mix whilst wind generation increased and comprised 8% of the total generation mix.

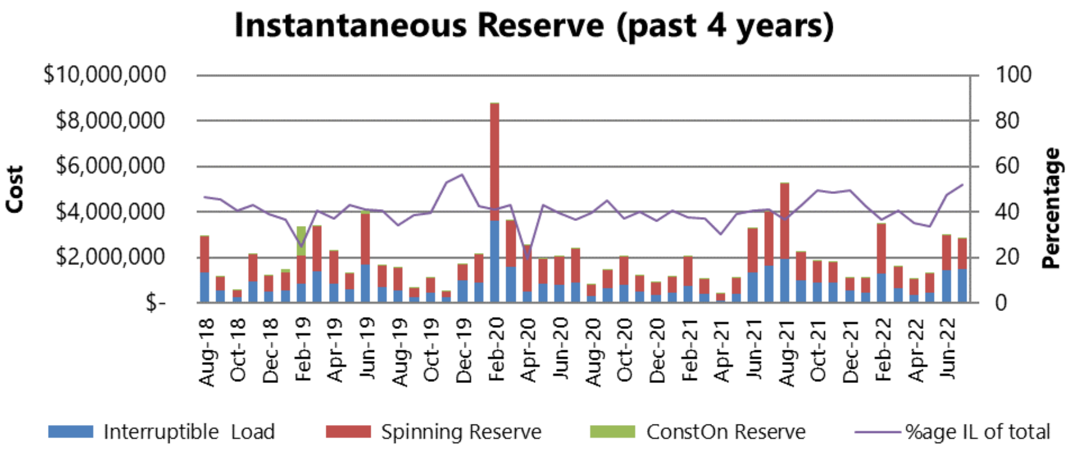
Average prices have dropped in response. From $190/MWh range at the start of the month to $100/MWh range at the end of the month. Notably, prices are highly volatile and are moving between a sub-$10/MWh range and a $200/MWh range depending on the level of wind generation. As storage increases, we are seeing more periods of sub-$10/MWh range prices.

As a result of the lower average prices, baseload thermal with a start-up time of 6 hours or more is beginning to drop out of the market when load is low and wind generation is high, and come back into the market over periods of forecast high peak demand and low wind generation. This is putting pressure on the System Operators 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 expert advice from a meteorologist to provide further insight for the forecast.

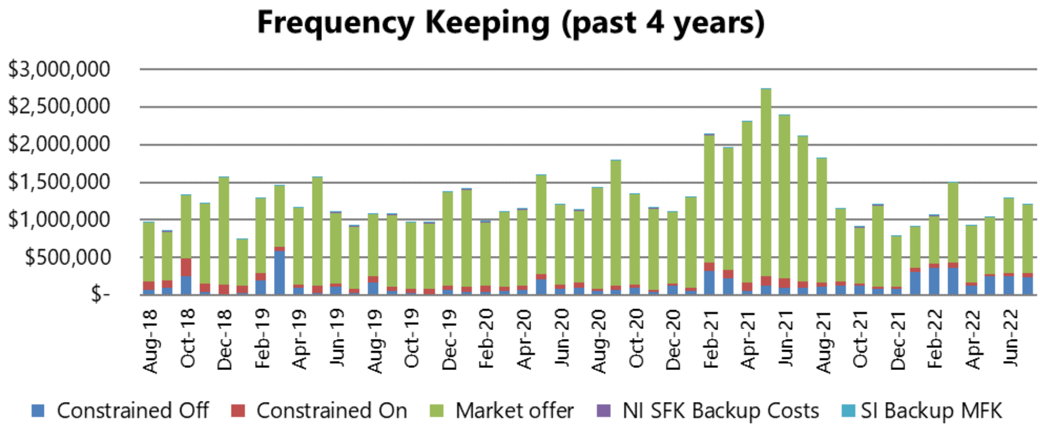
14 Ancillary services



This month's ancillary services costs were $4.29 million, a decrease of $232k (5% decrease) from the previous month. Instantaneous reserve and frequency keeping costs have both decreased compared to the previous month; instantaneous reserve costs decreased by $143k (5% decrease) while frequency keeping costs decreased by $89k (7% decrease).

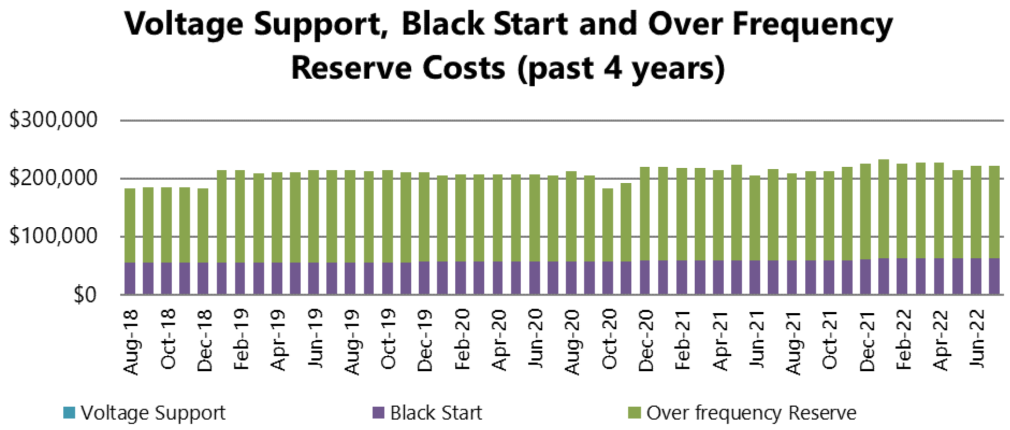


This month's instantaneous reserve costs were $2.87 million, a decrease of $143k (5% decrease). Overall quantities of both fast and sustained reserves were lower than the previous month. Quantities of fast reserves increased in the North Island while quantities of sustained reserves decreased. Quantities of both fast and sustained reserves decreased in the South Island. The average prices per megawatt of fast reserves decreased in both the North and South Islands while conversely sustained reserve MW prices were higher in both the North and South Islands.



This month's frequency keeping costs were $1,204 million, a decrease of $89k on the previous month (7% decrease). North Island frequency keeping costs increased this month by $135k (25% increase) while in the South Island frequency keeping costs decreased by $225k (30% decrease).

Constrained off costs decreased by $10k (4% decrease) while the constrained on costs increased by $1.5k (3% increase).



Over frequency costs stayed at the same level of close to $160k this month. Black start costs remained at $62k this month. There are currently no voltage support costs.

15 Commissioning and Testing

No items to report

16 Operational and system events

Under-frequency event

On 30 July 2022, an under-frequency event occurred when Huntly unit 5 tripped while at 190 MW. The System Operator will investigate the event and recommend a causer to the Authority.

23 June grid emergency

Ranil de Silva (PBA Consulting) has completed the independent review of the System Operator's performance during the grid emergency on 23 June 2022 and has circulated a draft report. The report notes that the new demand management processes implemented by the System Operator post-9 August 2021 were successfully followed to manage the generation shortfall with minimal disruption to consumers. The report also highlights the impractical manual collation of controllable load availability (via phone calls) and the Authority pursuit of a Code change to provide the System Operator with automated visibility of controllable demand.

Significant incident investigations

We continued to investigate three significant event which occurred in June:

- Event 4284 (multiple lightning strikes in June). We submitted a summary report to the Authority on 29 June and are now preparing a final report.
- Event 4285 (HVDC modelling during approval of reclose blocks in June – AUFLS near-miss). Investigation has shown that the system was not at risk. The Authority has been informed that this event will now not be treated as a 'moderate' incident and closed out via our internal process.
- Event 4292 (loss of supply at Hangitiki for more than 1 hour in June). The investigation is still underway.

Upper North Island voltage management

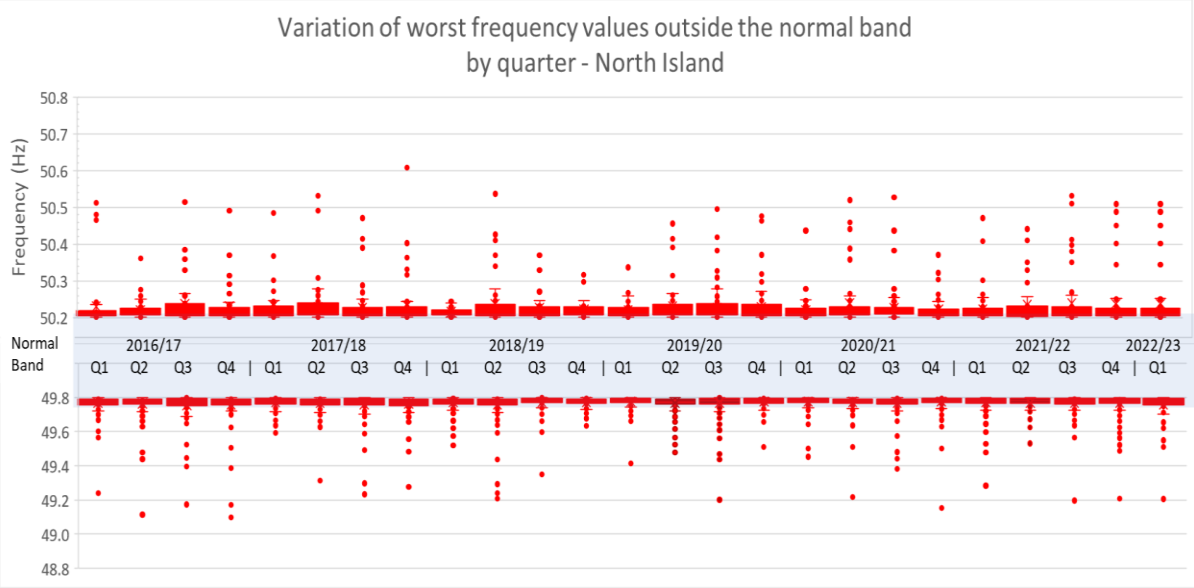
We are working through voltage management implications associated with bringing back into service the Brownhill–Pakarunga 2 cable. The Grid Owner has placed restrictions on the switching of cable circuits in the Upper North Island region which is one of the System Operators key mitigations alongside the use of reactive regulating assets in managing high voltage in the area.

17 Frequency fluctuations

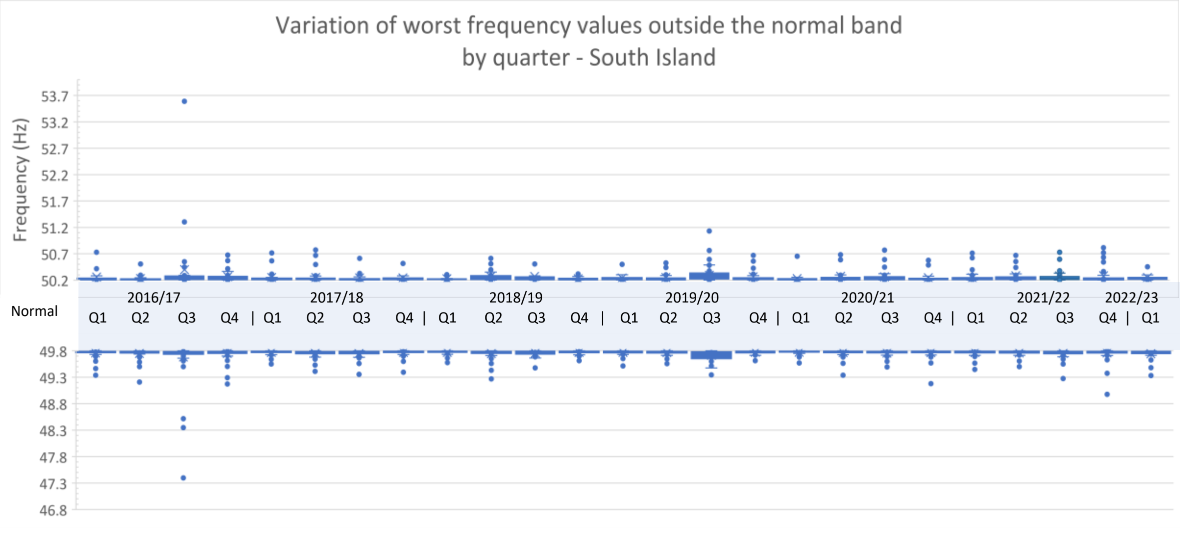
17.1 Maintain frequency in normal band (Frequency value)

The following charts show the distribution of the worst frequency excursion outside the normal band (49.8 to 50.2 Hz) during the reporting period.

North Island



South Island



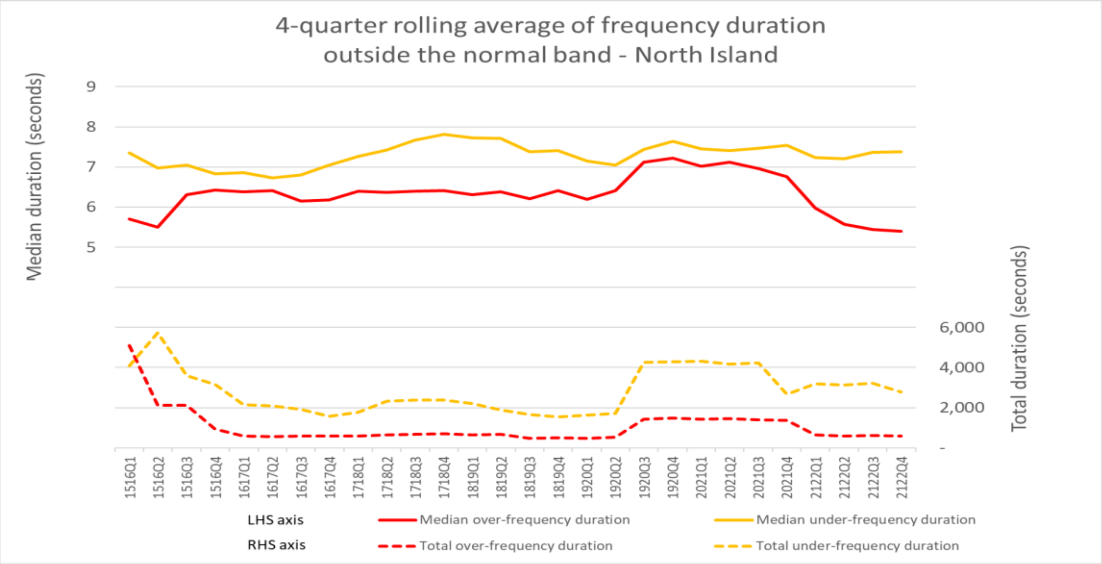
*2022/23 Q1 contains data for July only

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.

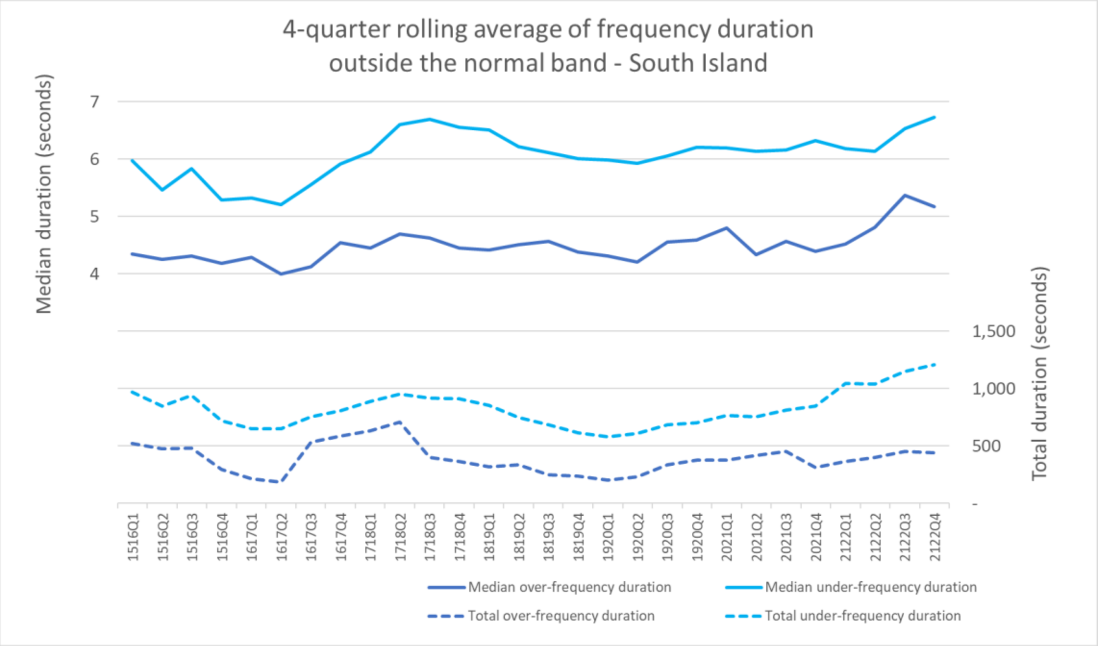
17.2 Recover quickly from a fluctuation (Time)

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

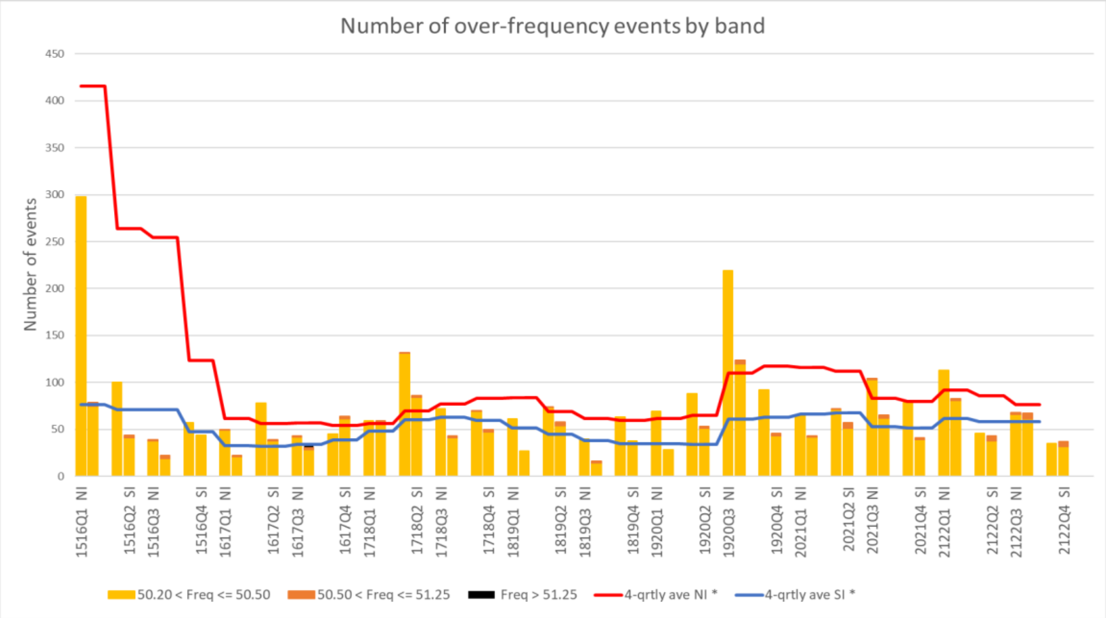


*These graphs have not been updated since 2021/22 Q4; they will only be updated at the end of each quarter

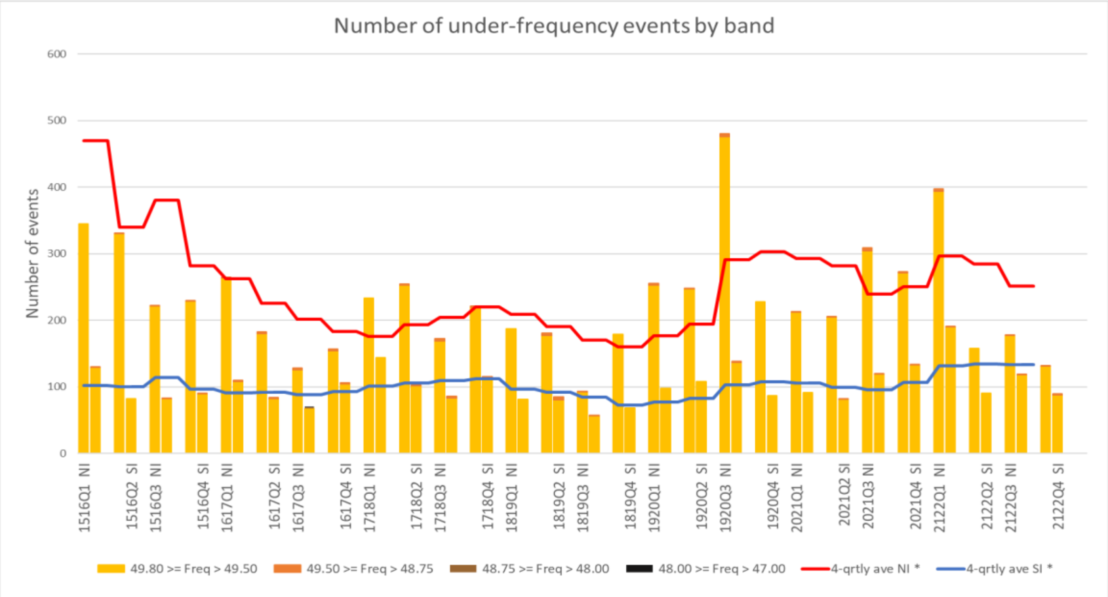
17.3 Manage frequency and limit rate of occurrences during momentary fluctuations (Number)

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. The information is shown by island, including a 4-quarter rolling average to show the prevailing trend.

Over-frequency events



Under-frequency events



* 4-quarterly rolling averages for NI and SI are only updated at the end of each quarter.

2022/23 Q1 contains data for July only

17.4 Manage time error and eliminate time error once per day

There were no time error violations in the reporting period.

18 Voltage management

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

19 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	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22
Demand Allocation Notice	-	1	-	--	--	-	-	-	-	-	-	-	-
Grid Emergency Notice	-	4	2	--	2	-	-	-	-	-	-	1	-
Warning Notice	1	4	-	--	--	-	-	-	-	-	1	-	-
Customer Advice Notice	11	42	34	9	7	5	7	9	15	14	15	28	24

20 Grid emergencies

None to report.

Appendices

Appendix A: Discretion

Event Date and Time	Description
11/06/2022 06:45	ARG1101 BRR0 For planned switching removal of ARG_BLN circuit. Last Dispatched Mw: 10
11/06/2022 17:27	ARG1101 BRR0 Discretion to 0MW to allow for BLN & KIK switching. Last Dispatched Mw: 11
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.
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.

Event Date and Time	Description
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
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.

Event Date and Time	Description
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).