MONTHLY SYSTEM OPERATOR AND SYSTEM PERFORMANCE REPORT

FOR THE ELECTRICITY AUTHORITY

Transpower New Zealand Limited

November 2020

Keeping the energy flowing

Transpower New Zealand Limited The National Grid

Report Purpose

This report is Transpower's review of its performance as system operator for November 2020, 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).

Table of Contents

This page is intentionally blank.

System operator performance

1 Highlights this month

- The Authority Board approved the SOSPA 2 proposal at its meeting on 3 December. Changes will take effect on 1 July 2021.
- The 2020 SSF completed in early December and was published on our website on 10 December. This confirms we are confident that we will be able to meet the Principal Performance Obligations (PPOs) over the next three years and continue to maintain a secure, reliable power system.
- There is a low risk to security of supply due to increased hydro flows during November and a decrease in demand. Pohokura's steady decline of supply since May means we are closely monitoring the situation and keeping the market appropriately informed of these developing risks.
- Real Time Pricing (RTP) phase 1 development is complete and system testing started. Business change engagement and planning started for phase 2. The Authority held the second of a planned series of nine industry engagement groups.
- There has been a lot of activity in integration testing and transitioning participants to the new dispatch platforms as part of the Dispatch Service Enhancements (DSE) project. One participant will not have all sites transitioned by the end of the year and we are working with another participant to address issues found in testing that risk their schedule date of completion in December.
- The first two of the five annual SOSPA business process audits have been completed - Managing insufficient generation offers and reserve deficits; Markets Security of Supply (Follow-up Review).
- On 23 November, we introduced 10-minute offload time (previously 15 minutes) on lines out of Southland which has an overall benefit to New Zealand customers to reduce the impacts of these constraints and increase transfer levels, when this is operationally feasible and secure.

2 Customers and other relationships

SOSPA 2 reset

The Authority Board approved the SOSPA 2 proposal at its meeting on 3 December. Changes will take effect on 1 July 2021.

Battery Energy Storage System (BESS) enquiries

We continue to support industry participant enquiries regarding how BESS might be configured to enable instantaneous reserves in the future. In order to remain fair and impartial, we are publishing on our external website a series of questions and answers on BESS, while still protecting individual participants confidentiality.

GM Stakeholder Meetings

Dr Jay met with executives from OMV, Beach Energy, Tilt, PowerCo and two Executives from the Authority.

3 Assurance

The first two of the five annual SOSPA business process audits have been completed - Managing insufficient generation offers and reserve deficits; Markets Security of

Supply (Follow-up Review). Both audits have independently assessed our processes as effective with only minor findings identified. These findings have been agreed by management and are now being tracked in our corrective actions register. The next two audits relating to Event Management and Contingency Principles are scheduled to be delivered between February–April 2021.

4 Compliance

We did not report any system operator self-breaches in November.

During the month we met with the Authority to discuss the alleged breach around the use of the same external legal provider by the system operator and grid owner in relation to the December 2018 UFE. The Authority is continuing to investigate this matter and we are providing the Authority with the information required.

We have seven outstanding breaches with the Authority compliance team.

5 Impartiality of Transpower roles

No items were opened in the register during November.

We have six open items in the register that are being actively managed in accordance with our Conflict of Interest procedure.

System Operator Open Conflict of Interest Issues		
ID	Title	Managed by
27	**System operator employee partner to work for grid owner:** The partner of a system operator employee started work with the grid owner. Confidentiality obligations have been explained to both employees and will be monitored to prevent a conflict of interest arising.	SO Power Systems Group Manager
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
31	**Discussions concerning Demand Response:** A system operator employee is part of a Transpower working group investigating the possible future use of the Transpower demand response platform. The system operator role is to provide the system operator perspective on any demand response proposals. Impartiality mitigations have been implemented to ensure the grid owner is not treated more favourably than any other participant with respect to demand response.	SO Market and Business Manager
33	**Sharing working space during lockdown:** A staff member sharing work-space with their partner who works for another industry participant. Both parties are managing the conflict accordingly to maintain the confidentiality of information.	Grid and Systems Operations Manager
39	**New SO Compliance & Impartiality Manager:** This relates to potential perception; the person filling this role also works for Transpower's legal team on a part-time basis. Workstreams will be allocated accordingly.	GM Operations
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

6 Project updates

6.1 Market design and system enhancement project updates

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

Real Time Pricing (RTP)
Development for Phase 1 is now complete, and the project is transitioning into formal testing. System testing started from 1 December and continues through to April 2021. The system code for the second phase of the Market System Simplification release 1 and RTP Phase 1 code has been merged into one code change update as agreed by the project advisory team for the purposes of the upcoming testing and combined release into production.

While the design and development teams will be supporting the Phase 1 testing and deployment, the focus is beginning to shift to Phase 2 activities. Business change engagement and planning is completed within our Operations division and change strategies have been agreed with each of the teams within the division. Development of the training tools for Phase 2 also progressed, updates to operational procedure documents will start in December.

The Authority held the second of a planned series of nine industry engagement groups in November. We presented material that outlined the obligations the system operator operates under when clearing the wholesale electricity market, what needs to be considered when solving for generation dispatch, how this will change under RTP and how this flows on to real-time price formation. The next session will be in February 2021 with the focus on how the power system affects price.

Dispatch Service Enhancements (DSE)
November has been another busy month for the DSE project. Integration testing and transition to the new dispatch platforms is planned with participants almost every day for the remaining three weeks leading up to Transpower's IST change freeze in mid-December. One participant has formally notified the Electricity Authority and Transpower that they will be unable to transition all sites this calendar year. We will continue to dispatch un-transitioned sites via the old platform, but the delays will put them in breach of the Code. A further party has a planned date for transitioning into production in December, there is a risk this participant may not transition as issues found during testing are still being worked through.

Situational Intelligence
Releases 1 and 2 of this project are now deployed; Release 2 was deployed to users in the control room on 26 November. The team are currently working to complete final development for Release 3, which will be completed in December and ready for deployment into production in January.

Extended Reserves (AUFLS)
Following the approval of the business case in late October, the high-level design and detailed planning are now underway. Planned activities include approval of high-level

design, completion of detailed planning, estimation/delivery checkpoint meeting with the governance group.

Sensitivity Schedules

The three-month proof of concept for this project is completed, all feedback has been collated and the project is in the process of being closed. We will carry out an evaluation of the proof of concept to determine whether to progress this as a market design/service enhancement capital project proposal to the Authority.

7 Technical advisory hours and services.

Technical advisory hours and a summary of technical advisory services 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

There have been a very large number of outages in November - a total of 795 planned outages, including 101 short notice changes. This has resulted in heavy workloads for the system security planning team. Planned outage numbers for the first three weeks of December remain very high, with numbers building for the new year.

We reviewed outages planned during the upcoming America's Cup regattas to identify risk to customers. We have collaborated with Vector to determine whether any changes may be required.

CUWLP Outages and Operational Impacts

In our role as system operator, we presented alongside the grid owner at the Energy Trader Forum on the Clutha and Upper Waitaki Lines Project (CUWLP). This was another opportunity to inform the industry of the works being completed, impacts during construction and future benefits. A second virtual industry briefing will be hosted by Transpower on 14 December. This will update the industry on project progress, works during the next stage (duplexing) and provide an impact on the 2021 HVDC outage (which is concurrent with the NSY-ROX-1 duplexing) and the HVDC outages to 2024.

NZGB analysis

The New Zealand Generation Balance (NZGB) report prepared in early December forecasts no N-1-G[1] generation shortfalls for the next six months. Applying a low gas assumption, N-1-G shortfalls are forecast in mid-April 2021 and late May 2021. The shortfalls in April 2021 coincide with the Huntly Unit 5 outage and several other smaller North Island hydro generation outages.

9 Power systems investigations and reporting

Market system outage greater than 1-hour investigation

Our investigation into the market system outage on 8 August 2020 completed and delivered on time to the Electricity Authority, by 8 November 2020. No root cause was identified for the incident by Transpower or our vendor. Additional system logging has

[1] The N-1-G balance is the system's capacity to cover, over the peak, the loss of the largest risk-setter if the next largest risk setter were also to become unavailable

been put in place to enable a diagnosis of a root cause should there be a reoccurrence. No breaches or actions were identified as a result of the investigation.

System Security Forecast (SSF)

The 2020 SSF completed in early December and was published on our website on 10 December. This confirms we are confident that we will be able to meet the PPOs over the next three years and continue to maintain a secure, reliable power system on which our customers and New Zealand's electricity consumers expect. Key findings include:

- the announced Tiwai Exit will tighten existing transmission constraints as a result of high generation export out of the Southland region.
- the potential displacement of thermal generation in the upper North Island would increase reliance on other North Island generation and HVDC transfer to meet demand.
- an increase of approximately 350 MW generation from new wind farms being commissioned in the Taranaki and Bunnythorpe regions stands to tighten some existing constraints in the central and lower North Island.

Operational Impact of Tiwai Exit

Preparations for Tiwai's exit are still tracking to plan. In December the initial results are due for a number of our more detailed engineering studies. We are still on track to be ready operationally for an August 2021 exit should it eventuate.

The SSF completed the assessment on steady state voltage management and concluded that we will be able to manage without the need for any sort of voltage support contract.

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

This will be provided to the Authority in December 2020.

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

During November national hydrology pushed upwards from 99 per cent to 112 per cent of average. Rising storage is typical for this time of year and has been driven largely by a prolonged period of above average inflows in the South Island. North Island hydrology also rose dramatically, from 100 per cent to 120 per cent of average. This is due both to improved inflows in the North Island (including a major inflow event associated with the Napier floods) as well as reduced generation on the Waikato hydro chain. In early December, North Island storage decreased slightly but remains well above average at 83 per cent of full.

Due to its size, North Island hydrology has a lesser impact on the national storage position than the South Island. However, it does have a large influence on price. Typically, when both North and South Island hydrology are strong we see low pricing periods. As a result of currently strong hydrology and lowered demand (associated with warmer months) prices have averaged below $100/MWh in the second half of November. This is the first time since May that average prices have dipped so low.

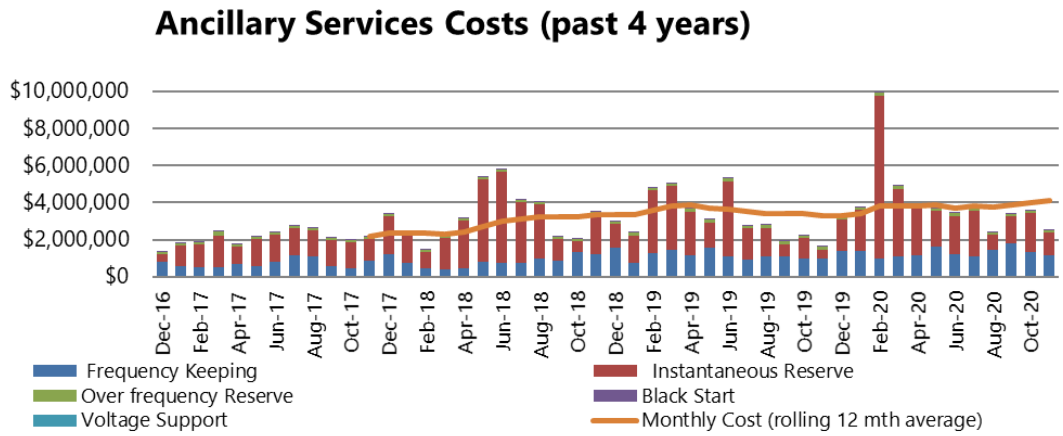
Decreased demand, as summer approaches, also results in low risk to security of supply. However, looking ahead to autumn and winter of 2021, when risks are expected to peak, there are two key issues that are being monitored:

1) Gas supply - New Zealand's largest gas field, Pohokura - operated by OMV - has been experiencing steady decline of supply since May. OMV have recently downgraded their production forecast for 2021 by approximately 100 TJ per day. This is approximately 20 per cent of national gas supply. This level of gas production would be similar to that observed in the Spring of 2018 during an unplanned outage of Pohokura's offshore wells. If this happens, it is likely our major gas generators will need to secure gas from third parties, of which the most probable option is Methanex. An advantage of this risk currently over the 2018 shortage, is that the market is aware of the current Pohokura issue, and generators should be able to secure gas supply in a pre-emptive and planned nature this time around.

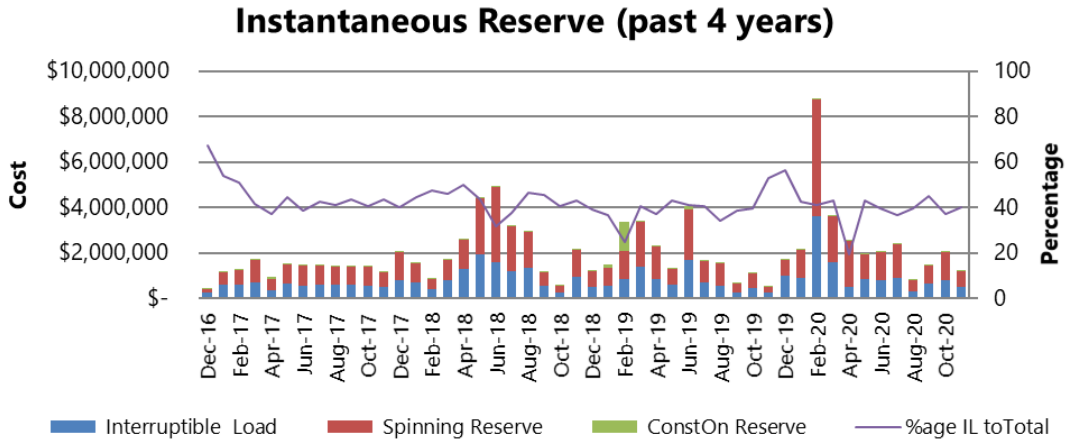
2) Climate - NIWA have formally announced that a La Niña event is taking place. La Niña events typically lead to increased north-easterly winds and reduced rain in southern hydro catchments. Previous La Niña inflow sequences show a trend of above average inflows in late spring and early summer, followed by below average inflows in late summer and autumn.

We are monitoring the situation closely and keeping the market appropriately informed of these developing risks.

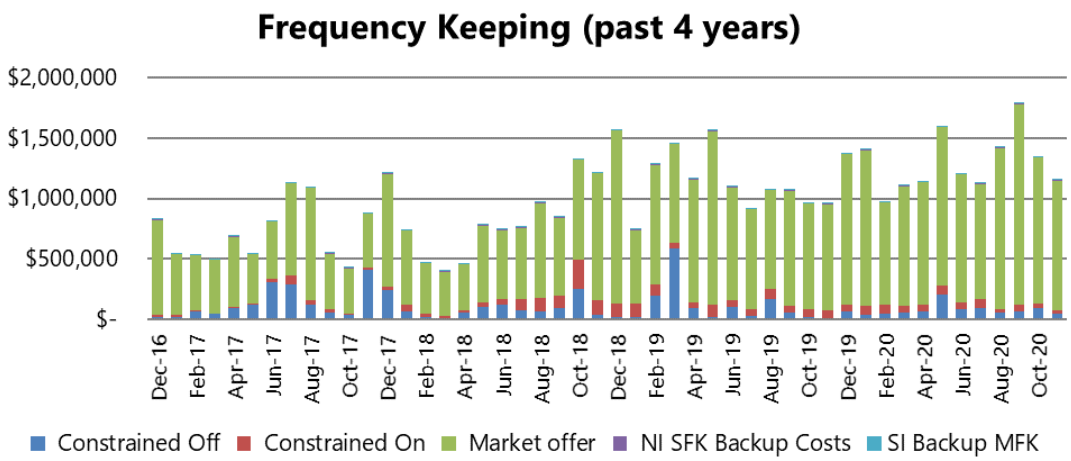
14 Ancillary services



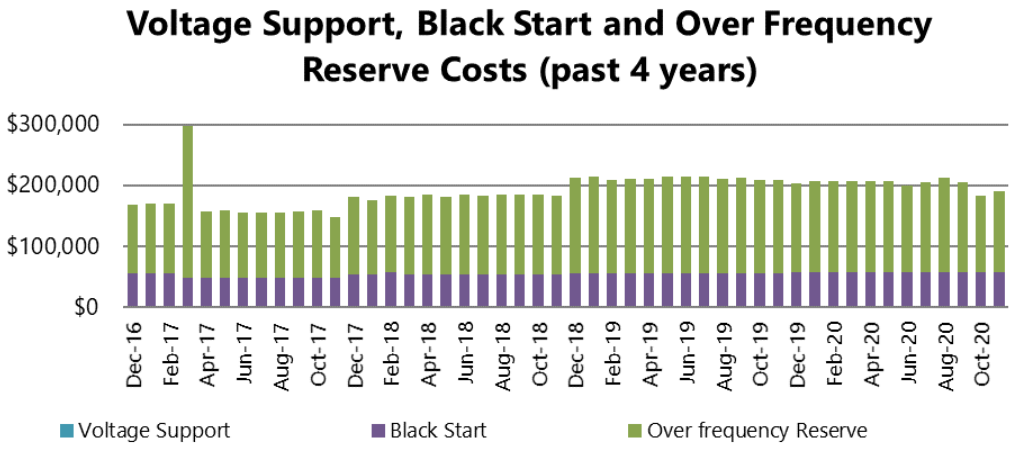
This month's ancillary services costs were $2.6 million, a decrease of $1.1 million (30 per cent decrease) from last month. This arose from a decrease in both instantaneous reserve costs and frequency keeping costs.



This month's instantaneous reserve costs were $1.2 million, a decrease of $894k (43 per cent decrease) from the previous month. $583k of this increase is attributable to spinning reserves, and $296k to interruptible load. In the latter part of the month, the volume of reserves required dropped, when lower levels of risk required covering as a consequence of changes in risk setting plant. The price of reserves also dropped during this period.



This month's frequency keeping costs were $1.2 million, a decrease of $188k to the previous month (14 per cent decrease). This was partly due to the changing mix of frequency keeping providers with improved South Island hydro levels.



The over frequency costs increased slightly this month to $133k. Black start costs remained at $58k. There are currently no voltage support costs.

15 Commissioning and Testing

Generation testing, commissioning and model changes

Waipipi windfarm started injecting into the power system in November. Commissioning of the turbines also started this month and will carry on through until February next year. Originally the windfarm was treated as both a secondary contingent and extended contingent risk. In an improvement to our process, we have been able to limit the risk to the actual output of the windfarm rather than the full rated output. Initial testing of the first string of turbines allowed us to remove the secondary contingent event risk quickly and reduce the amount of additional reserves needed to the benefit of end consumers. Waipipi will remain a secondary extended contingent event for the full duration of commissioning but should have minimal impact on reserves.

Both Ngawha and Turitea North windfarms commissioning dates continue to slip. We continue to meet our system operator deliverables, but these slippages may result in commissioning work occurring over Transpower's summer shutdown period (24 December 2020 to 11 January 2021, inclusive). We will continue to monitor the situation.

16 Operational and system events

Introduction of 10-minute offload time on 23 November 2020

During late 2020, through 2021 and into 2022, there will be lengthy outages related to the Clutha and Upper Waitaki Lines Project (CUWLP). During these outages, maximum Lower South Island generation transfer levels out of the region will be constrained to the N-1 capacity of the remaining two connected circuits.

There is an overall benefit to New Zealand customers to reduce the impacts of these constraints and increase transfer levels, if operationally feasible and secure. This can be achieved by running circuit offload times down to 10 minutes for these circuits provided predefined conditions are in place to ensure security is reliably maintained. This allows approx. 20 MW of extra flow out of the region during the Clyde-Cromwell-Twizel outages and 50 MW during Naseby-Roxburgh and Livingstone-Naseby outages.

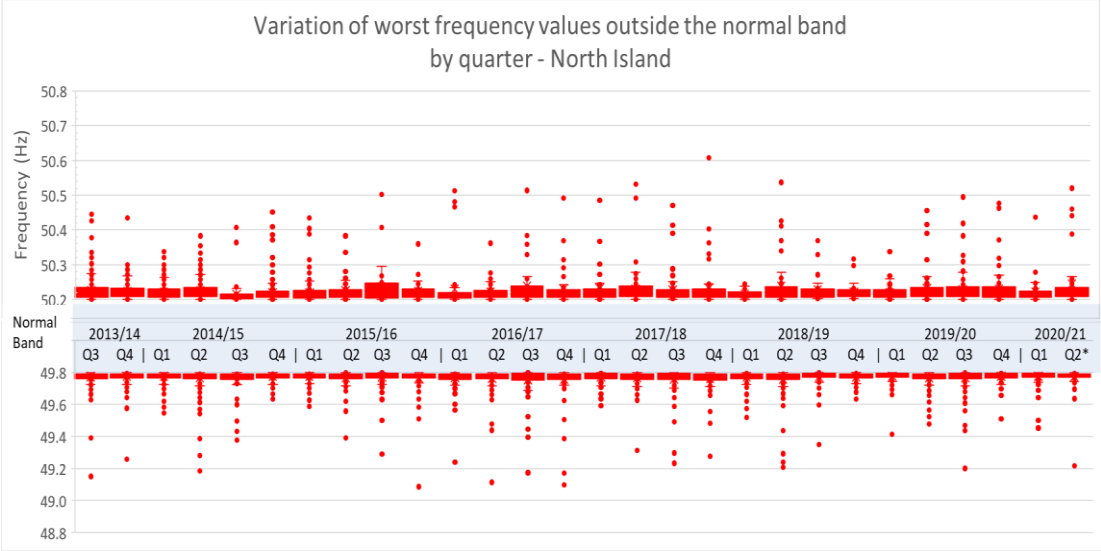
The proposal was socialised with industry participants for feedback. This was predominantly positive on the proviso that sufficient notice is provided to the market and that there are clear criteria for any future requests. A combination of original definitions (at 15 minutes) and the new 10-minute definitions will be used to optimise the process in the control room.

17 Frequency fluctuations

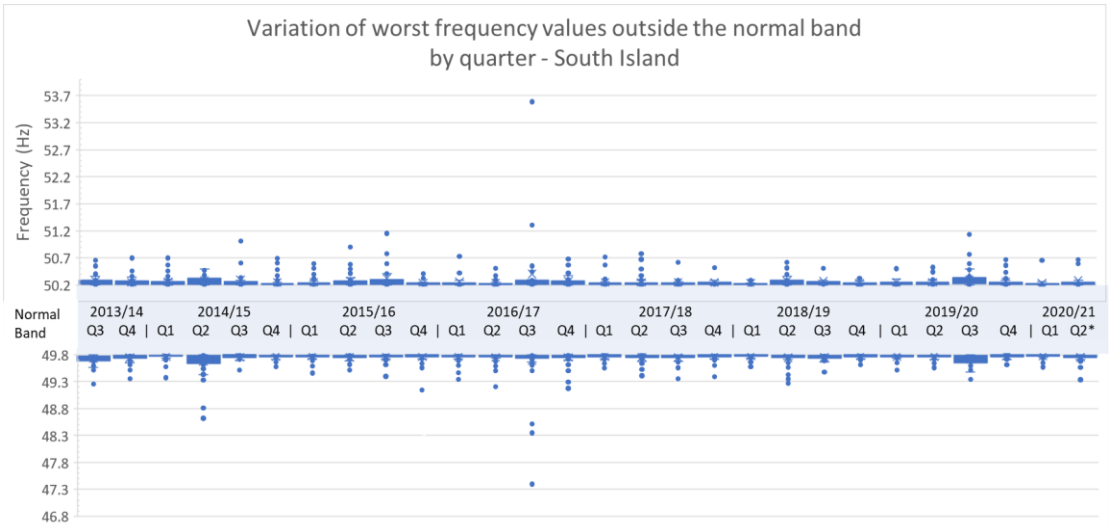
17.1 Maintain frequency in normal band (Frequency value)

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



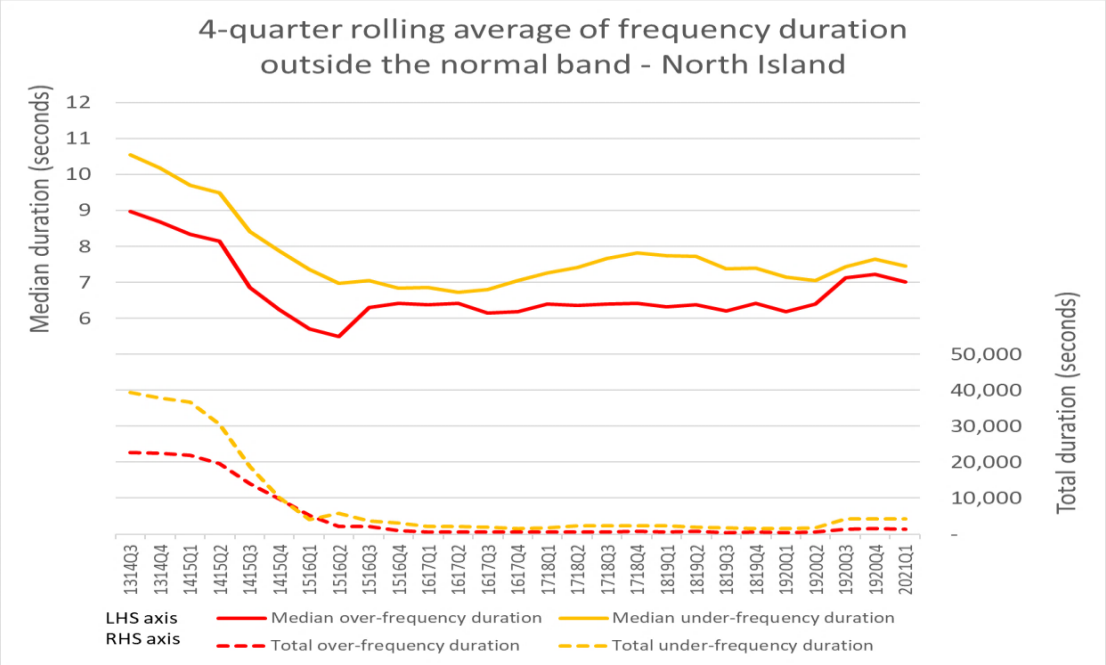
* 2020/21 Q2 contains data for October and November only

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.

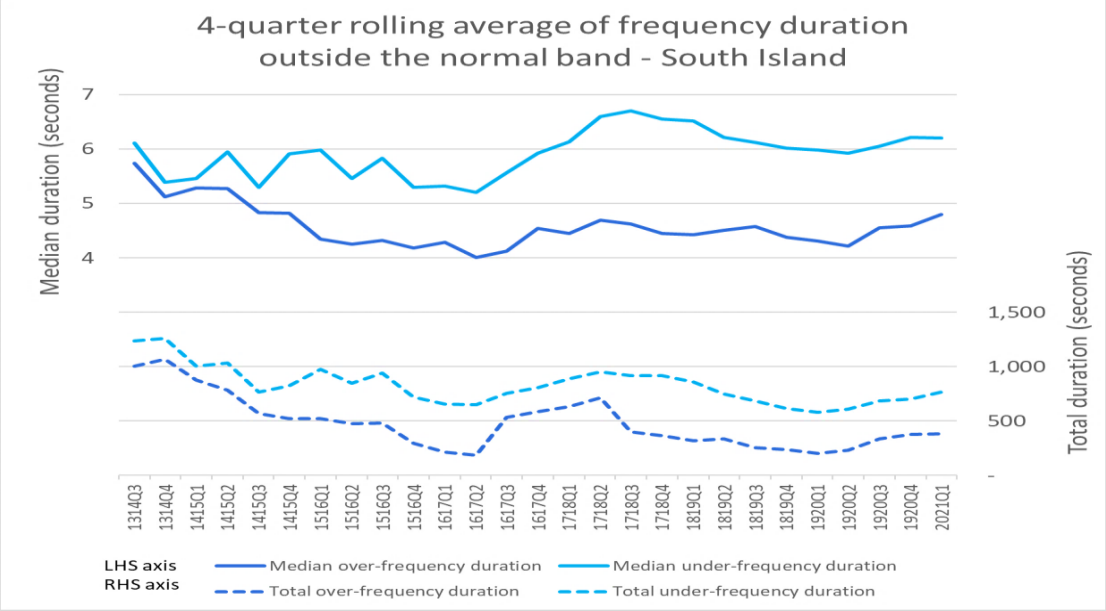
17.2 Recover quickly from a fluctuation (Time)

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

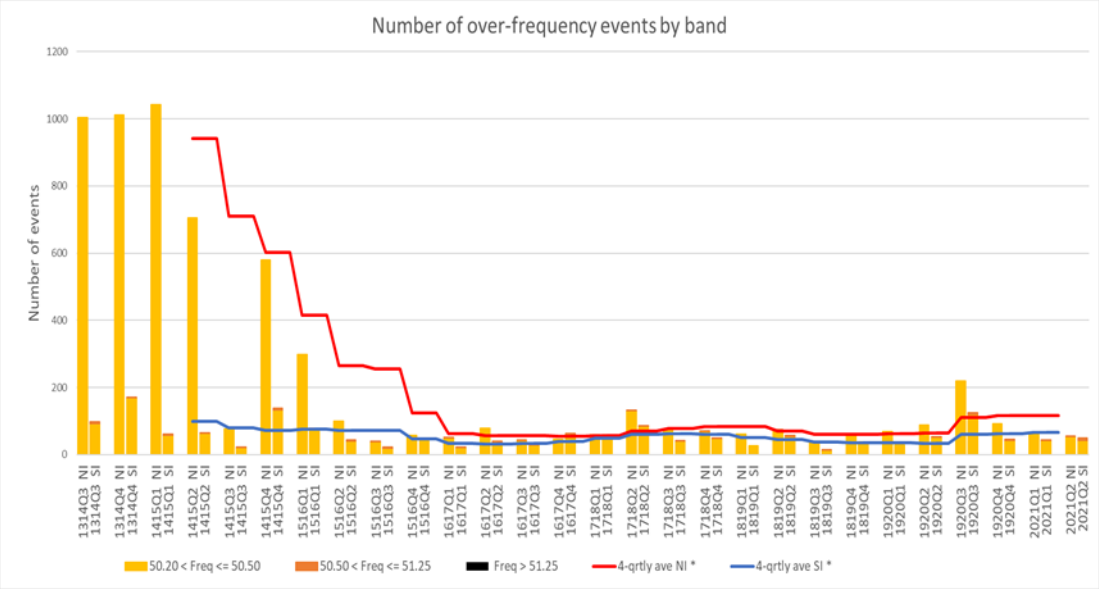


* These graphs have not been updated since 2020/21 Q1; they will only be updated at the end of each quarter

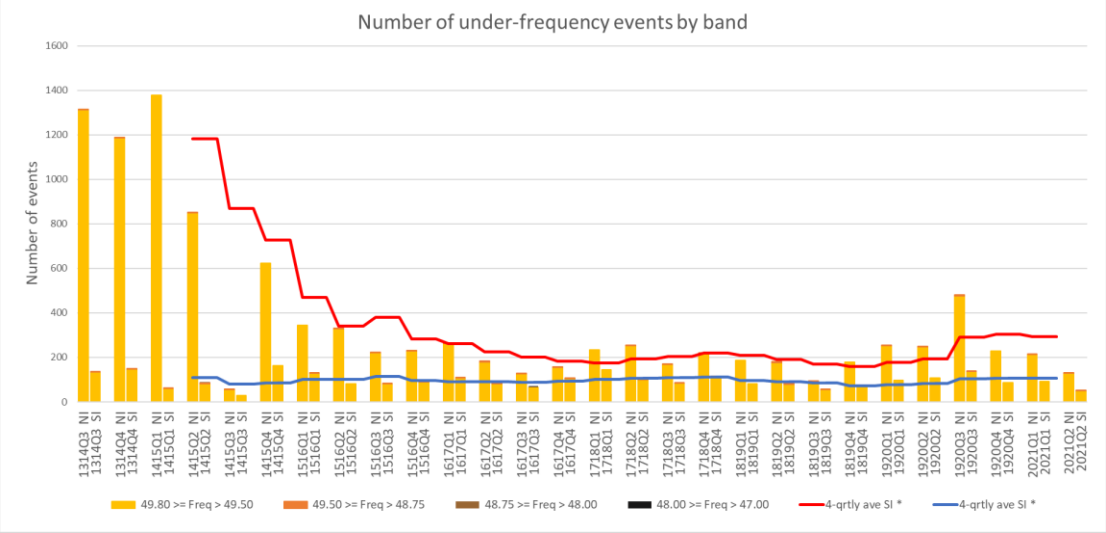
17.3 Manage frequency and limit rate of occurrences during momentary fluctuations (Number)

The following charts show the number of momentary fluctuations outside the frequency normal band, grouped by frequency band, for each quarter since 2014. The information is shown by island, including a 4-quarter rolling average to show the prevailing trend.

Over-frequency events



Under-frequency events



Note: The 2020/21 Q2 contains data for October and November only.

* 4-qtrly averages for NI and SI will only be updated at the end of each quarter

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	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20
Demand Allocation Notice	-	-	-	-	-	-	-	-	-	-	-	-
Grid Emergency Notice	-	-	-	1	-	-	1	-	-	-	1	-
Warning Notice	-	1	-	2	-	-	-	-	-	-	-	-
Customer Advice Notice	14	6	21	14	13	10	13	11	15	9	6	12

20 Grid emergencies

The following table shows grid emergencies declared by the system operator.

Date	Time	Summary Details	Island
		None	

Appendix A: Discretion

Event Date and Time	Description
10-Nov-2020 01:20	SFD2201 SPL0 Discretion Max : 0 Last Dispatched MW: 151.17 : Test solves to check pricing at 0MW and 160MW to determine the best overall outcome to meet dispatch objective.
10-Nov-2020 01:21	SFD2201 SPL0 Discretion Min : 160 Last Dispatched MW: 151.17 : Test solves to check pricing at 0MW and 160MW to determine the best overall outcome to meet dispatch objective.
18-Nov-2020 06:04	SFD2201 SPL22 Discretion Min : 6 Last Dispatched MW: 0 : To prevent the unit being switched off this this period and then on again next period. Will be dispatched back on again shortly.