QUARTERLY SYSTEM OPERATOR AND SYSTEM PERFORMANCE REPORT

FOR THE ELECTRICITY AUTHORITY

Transpower New Zealand Limited
October to December 2020

Keeping the energy flowing




TRANSPOWER

Transpower New Zealand Limited The National Grid

Report Purpose

This report is Transpower's review of its performance as system operator for Q2 2020/21 (October to December 2020), 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).

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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 (October to December 2020)

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.

Real Time Pricing (RTP) and awareness preparations

- RTP phase 1 development is complete and system testing started. Business change engagement and planning started for phase 2.
- Transpower supported the Authority with the first two industry workshops on RTP in October and November, with seven more planned in this series through the next few months.
- The project continues to track to both schedule and budget, there are currently no high or severe risks under management.

Tiwai exit and Clutha Upper Waitaki Lines Project (CUWLP)

- High workload was observed throughout the quarter as a result of the warmer weather and a large number of outages being planned.
- Tiwai exit angular stability and over-frequency arming studies have been completed, with the report and recommendations expected early 2021.
- On 23 November, following consultation with the industry, we introduced 10-minute offload time (previously 15 minutes) on lines out of Southland to support the CUWLP work. This 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.

Security of Supply

- Although both the North and South Island hydro storage positions started the quarter strongly as a result of spring inflows and lower demand, storage is now declining. For this time of year, it reflects 86% of average and is just above the bottom 10th percentile. However, decreased demand as summer approaches, results in low risk to security of supply.
- Looking ahead to autumn and winter of 2021, when risks are expected to peak, there are two key issues/risks that are being monitored:
  - Gas supply, production declines at Pohokura are forecast to see national gas production fall 20 per cent on 2020 levels.
  - Climate trend, current La Niña conditions indicate we can expect below average rainfall in the southern hydro catchments.
- As part of our commitment to continuous improvement, over the last year we have undertaken a number of activities to provide assurance of our preparedness for a dry winter event.

Code and SOSPA deliverables

- We completed the latest major update to System Security Forecast (SSF) and published it 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.
- 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).
- The draft SO Service Strategic Plan and draft SO ICT Strategic Roadmap were delivered on 18 January and will be discussed at the Authority's System Operations Committee meeting on 3 February.

Dispatch Service Enhancements (DSE)

- By 16 December, 11 of the 13 current dispatch participants using the legacy dispatch system (GENCO) have transitioned, five with ICCP block 2 protocol and six with webservices. One of these participants has fully decommissioned their GENCO system.
- Of the remaining two participants – one has transitioned some of but not all of its sites, the other transitioned to ICCP in production but then removed this at their end in order to complete full regression tests with Transpower (expected to be completed in February).
- There were late issues in production with another party, who have rolled back to GENCO as a manual work-around until January.

System operator self-breach

- We reported one breach during October relating to a failure to publish a schedule on time; this was due to an ongoing market system issue for which a permanent solution to the defect is being sought.
- In January, we reported a self-breach for the period 27 November 2020 to 15 December 2020, when the system operator did not include Glenbrook power station's instantaneous MW injection values in the real time pricing (RTP) schedule.

Recent initiatives

Sensitivity schedules

- The project is now closed. We have collated feedback and 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.

Current investigations

Market system outage greater than one-hour

- No root cause was identified for the incident on 8 August 2020, by Transpower or our vendor. We have put in place additional system logging 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 operator performance

1 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. As well as securing the funding terms for the next four years, the other key changes to the SOSPA are:

- a change to the mechanism for charging for technical advisory services provided to the Authority, which better balances the need for flexibility for the Authority, without compromising Transpower's resourcing model for this work.
- an amendment to prevent Transpower charging participants for core services provided under the SOSPA. This was needed following legal advice that the Electricity Industry Act prohibited the Authority from granting approval to this.
- clarification that Transpower must seek approval for any increased expenditure in an Authority-funded Market Design or Service Enhancement project.
- amendment to the clause requiring the system operator to assist the Authority give effect to its statutory objective, to specifically refer to consideration of impact on participants of its decision-making.

CUWLP outages and operational impacts

In October, we consulted with the industry prior to introducing a 10-minute offload time on lines out of Southland.

We presented at the Energy Trader Forum in November and held an industry briefing on the next set of CUWLP work in December. More detail is included in section 7 of this report.

GM Stakeholder Meetings

Dr Jay met with executives from OMV, Beach Energy, Tilt, PowerCo and two Executives from the Authority. He also attended APeX and CIGRE board meetings. The former is arranging a webinar on market design to accommodate storage in February.

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.

2 Risk & Assurance

COVID-19 response

New Zealand has been operating at a reduced level of lockdown. However, with the emergence of new strains and the ongoing risks, our Incident Management Team continues to meet as required. Access to the control rooms remains limited and the physically separated system operator control desks remain in place are tested twice weekly. We are confident that the Level 4 protocols could be restored within 24 hours should this be required.

Impact of Tiwai exit

Our working group has developed a task list to assess and plan for the implications. Details, including the impact of the announcement in January of the deferral of Tiwai exit to 31 December 2024, are included in section 8 of this report.

Business process audits

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.

Risk bowtie and critical controls

We completed the control-self assessment process. The operations teams made assessments of their control environments; the senior leadership team reviewed and confirmed their critical control's effectiveness.

3 Compliance

October

We reported one system operator self-breach of the Code in October.

On 14 and 27 September, the automatic 00:00 NRSL schedules failed to complete within the time period specified in the Code. The schedules were completed manually and subsequently published. The cause of the issue is a defect in a component of the market system. There was no market or operational impact, as a result of the breach, and the Transpower IST team is working on a permanent solution to the defect.

On 30 October 2020, Genesis Energy's Huntly unit 4 tripped, removing 144.4 MW of injection into the power system. As a consequence, the North Island frequency fell to 49.22 Hz, which constitutes an under-frequency event. Instantaneous reserve providers responded, returning the frequency to the normal band within 17 seconds. Genesis Energy stated that it believes the tripping of Huntly unit 4 was the cause of the under-frequency event and the system operator's investigation supports this position. Accordingly, the system operator submitted a causer recommendation report to the Authority on 23 December 2020.

November

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

December

In January 2021, the system operator reported a self-breach relating to December. For the period 27 November 2020 to 15 December 2020, the system operator did not include Glenbrook power station's instantaneous MW injection values in the real time pricing (RTP) schedule. This resulted in Glenbrook's generation output being set to zero in the RTP schedules.

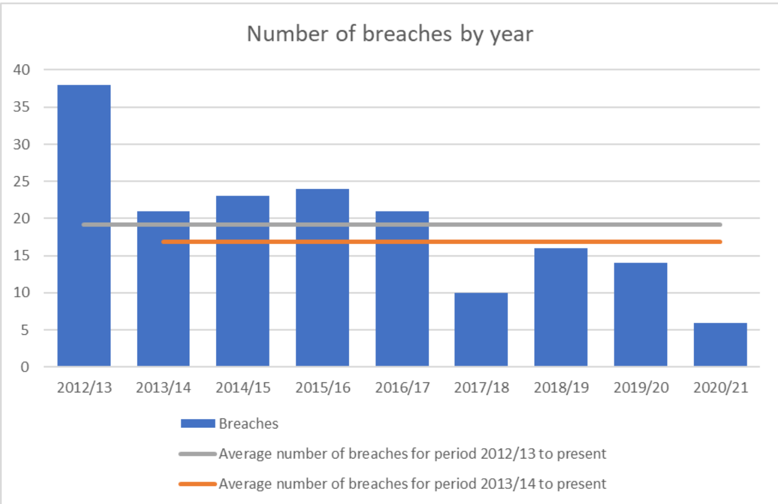
The RTP schedule sends a 5-minute price signal to the market via WITS, but is not used to dispatch, generate forecast schedules, or calculate final pricing. The error was caused by incomplete process documentation that has been updated.

Update on previous alleged breaches

The Authority alleged two breaches against the system operator in September.

- On 11 September, the alleged breach related to Transpower's system operator and grid owner using the same external legal provider in relation to the December 2019 under frequency event. The system operator met with the Authority on this matter and the Authority has submitted its recommendation for the next Compliance Committee meeting.
- On 18 September, the alleged breach related to the review cycle of the Procurement Plan. Although the system operator does not believe it breached the Code and worked in good faith to deliver the procurement plan according to its interpretation, the system operator has agreed to accept the Authority's finding in this matter.

We have eight outstanding breaches with the Authority compliance team, six from 2020/21 including the alleged breaches by the Authority in September.



Appendix A shows instances where the system operator has applied discretion under 13.70 of the Code.

4 Impartiality of Transpower roles

The entries in the table below are the open issues in the conflict of interest (COI) register. These issues are being actively managed in accordance with our policy for managing conflicts of interest.

The dates below refer to the calendar months and not the dates of the Monthly reports which cover 10 (or in the case of January, 20) business days of the following calendar month.

October

No items were opened in the register during October.

November

No items were opened in the register during November.

December

No items were opened in the register during December.

We have six open items in the register.

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

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.

Real Time Pricing (RTP)

Development for Phase 1 (detailed solution design, build and functional testing) is now complete, and the project is transitioning into formal testing. System testing started from 1 December and continues through to April 2021. The team continues to turn defect resolution around quickly avoiding any test delays. Deployment planning for Phase one continues and remains on track for deployment in early May 2021, a month ahead of the original scheduled date. Deployment planning is continuing with team walkthroughs underway now.

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. As a result, inter-project dependency management has been a key focus area with close monitoring of projects with the potential to affect RTP project timelines. This has resulted some adjustment to the delivery dates of other projects to maintain sufficient space in the release plan for a low risk deployment of RTP Phase 1.

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.

Transpower supported the Authority with the first two industry workshops on RTP in October and November. Seven more industry workshops are planned in this series through the next few months. In the second workshop, 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, or how does price creation relate to the real world.

The project continues to track to both schedule and budget, there are currently no high or severe risks under management.

Dispatch Service Enhancements (DSE)

The final date for participants to transition to the new service (and continue to meet their Code obligations) was 16 December 2020. 11 of the 13 current dispatch participants using the legacy dispatch system (GENCO) have transitioned, five with ICCP block 2 protocol and six with webservices. One of these participants has fully decommissioned their GENCO system.

This quarter was a busy period, progressing participants transition to the new dispatch platforms. Towards the end of the period, there was activity almost every day 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. Several of the remaining sites are planned for transitioning in early February.

A further party transitioned to ICCP in production, however, have since removed this on their end in order to complete full regression tests with Transpower – which are expected to be completed in February.

We will continue to dispatch un-transitioned sites via the old platform, but the delays put participants in breach of the Code.

Another party experienced some issues in production. They have rolled back to GENCO as a manual work-around until January, when the issues can be resolved with technical teams back in the office.

Situational Intelligence

During this quarter, Release 1 and Release 2 of this project have been deployed.

Release 1 (sprints 1 to 10) deployed the core Situational Intelligence platform into production, including simple alerts for market and SCADA data. There was a slight delay of a few weeks in Release 1, from early October to 22 October; this was deferred due to unrelated market system issues.

Release 2 (sprint 11) was deployed to users in the control room on 26 November. Release 2 is focused on adding Transpower sign-on and role-based authentication. The functionality of the application allows simple rules and alerts to be created using a subset of SCADA and market data.

Release 3 (sprint 12 onwards) continues to build functionality by incorporating more data into the application, allowing more complex rules to be built. Final development for Release 3, was completed in December and a Test Exit Report approved. The final deployment of Situational Intelligence is planned for 26 January, alongside a final tidy-up and transition to operational activities.

Extended Reserves (AUFLS) Portal, and Customer Portal–Asset Capability Statement (ACS)

The business cases for the Extended Reserves (AUFLS) Portal and Customer Portal ACS were approved in late October. Due to similar development trajectories, these two projects are currently being run together.

Since approval, IST have been working on completing the high-level design, which works through the technical aspects of these solutions. The estimation and delivery checkpoint meeting on 17 December 2020 highlighted some high-level design challenges. Management have requested the projects be re-baselined with realistic timeframes and to present options that will deliver by 30 June 2021 prior to the next Project Advisory Team meeting on 2 February 2021.

5.2 Other projects

Sensitivity Schedules

The three-month proof of concept finished at the end of October. We have collated the feedback from nine forms with the majority supporting the initiative. The project is now 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.

Modifying vSPD for Real Time Pricing stakeholder engagement work

A copy of vSPD has been modified, under a Technical Advisory Services agreement, to reflect the changes to be implemented under the RTP project; specifically, the functionality required for scarcity pricing and outage infeasibilities. This piece of work will enable the proposed changes to be shared, part of the plan to communicate and engage with industry.

By agreement with the Authority, the date for completion was extended to 28 October to allow for the latest RTP project SPD design changes to be accommodated in the vSPD build. The work incorporated three incremental vSPD deliverables of which the third and final was delivered in this quarter.

6 Technical advisory hours and services

The following table provides the technical advisory hours for Q2 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 Q2
TAS SOW 92 - Modifying vSPD for RTP stakeholder engagement work	In progress	141.50
TAS SOW 93 – Extended Reserves data portal capital business case development	In progress	50.45
TAS SOW 94 – Extended Reserves Code amendment support	Closed	117.00
TAS SOW 95 – Battery Energy Storage Systems Offering Reserve	Signed off, will start in Q3	-
TAS SOW 96 – Reliability standards for inverters	Signed off, will start in Q3	-
TAS SOW 97 – RTP engagement session support	In progress	124.00
Total hours		**432.95**

7 Outage planning and coordination

Outage Planning – near real time

The current trend of a high volume of outages requiring assessment continued over this quarter, including a significant amount of short notice changes; total outages were 908 in October, 795 in November and 591 in December. These all have associated workload implications and resulted in heavy workloads for the system security planning team. Numbers continue to build for the new year.

For example, the cable joint fault for Pakuranga-Whakamaru resulted in around 10 weeks of reassessment of Upper North Island outages and some rescheduling.

Given increased workloads we are working with the grid owner to more closely monitor forward workloads, and actively managing outage start times to reduce peak workloads in both grid and system operator control rooms.

CUWLP outages and operational impacts

The system operator continues to provide analysis and support to industry for the Clutha and Upper Waitaki Lines Project (CUWLP) outages.

On 23 November, following consultation with the industry, we introduced 10-minute offload time (previously 15 minutes) on lines out of Southland to support the CUWLP work (see section 15 of this report for more details). The system operator also published a new frequency management constraint to industry. This constraint will only be used when there is a risk of separating the Southland area from the main grid in the event of a fault.

In our role as system operator, we also presented alongside the grid owner at the Energy Trader Forum on 12 November. This was another opportunity to inform the industry of the works being completed, impacts during construction and future benefits.

Following the completion of the thermal upgrade of the Cromwell-Twizel line we held an industry briefing on the outages and operational impacts of the next set of CUWLP work on the Naseby-Roxburgh line. We also provided information on the upcoming HVDC outages in February 2021. In preparation for the Naseby-Roxburgh outages we have also prepared new constraints and communicated these to participants.

A website for the CUWLP outages has been set up to provide further information and updates to industry.

Outage Planning – longer term

We will be presenting to participants at the annual outage planning forum in March and be assessing the grid owner's annual outage plan for security implications.

New Zealand Generation Balance reporting

December's New Zealand Generation Balance Report forecasted 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

[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

coincide with the Huntly Unit 5 outage and several other smaller North Island hydro generation outages.

The system operator has adjusted NZGB so that it uses 2019 load data for all forecasts in the 2021 calendar year (instead of 2020 load data). This is to remove the impact of COVID-19 lockdowns from the load profile.

8 Power systems investigations and reporting

System Security Forecast (SSF)

The 2020 SSF was completed in early December and published on our website on 10 December. This confirms we are confident that we will be able to meet the Principal Performance Obligations 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. (Note that the SSF update was completed on the basis of an August 2021 Tiwai exit.)
- 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

A working group has been considering implications on our ability to operate the power system post-Tiwai exit and has developed a task list to assess and plan for the implications. Given the announcement in January of the deferral of Tiwai exit until 31 December 2024, the working group has reviewed the tasks and determined which will continue as planned and which will be paused until a later date.

The System Security Forecast has assessed the steady-state thermal transfer limits, voltage stability limits and high voltage management across New Zealand. It concluded that we will be able to manage without the need for voltage support contracts.

Two other streams of work that were progressed and will continue (which represent a conservative worst case, assuming some Tiwai load):

- South Island Transient (Rotor Angle) Stability Analysis: All preparation works, including generator model building, study scenarios and contingency definition, were completed and initial studies completed. We expect to finalise the findings and recommendations in early 2021.
- South Island Over-Frequency performance analysis: This study assesses the adequacy of over-frequency arming generators in the South Island following a bi-pole tripping of the HVDC post the Tiwai Exit. This will ensure we procure enough over-frequency generators to avoid constraining the HVDC north flow. Preparation works on generator model building, study scenarios and contingency definition were completed; the initial studies were also completed. We expect to finalise the findings and recommendations in early 2021.

- Studies will also commence in January looking into small signal stability across the South and North Islands.

A page was published on the Transpower website to keep industry informed of the findings from our operational studies into the impact of Tiwai's exit on our ability to operate the power system.

Market system outage greater than one-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 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.

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		82%	N/A	5
Annual participant survey result response rate - First tier stakeholders		80%	N/A	
On-time special event preliminary reports		90% ≤ 10 business days	0 to date	5
Future thinking and insights	Future thinking report	≥ 1	0 to date	5
	Longer Market Insight reports	≥ 4	1	5
	Bite-sized Market Insights	≥ 45	25	
Quality of written reports		100% of standard	100%	
Role impartiality		80%	N/A	5
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% (54)	100%	10
Successful project delivery				
Improved project delivery	Service Maintenance projects	≥ 60% on time	0%	
		≥ 60% on budget	100%	
	Market Design and Service Enhancement projects	≥ 60% on time	0 to date	
		≥ 60% 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	93%	5
High spring washer resolution		80% ≤ 10am or equiv	0 to date	
Dispatch Accuracy	Energy (Optimal dispatch)	Baseline set during 2020/21		
	Reserve Management Objective	Baseline set during 2020/21		

Fit-for-purpose tools

Capability functional fit assessment score	75.00%	N/A	
Technical quality assessment score	65.00%	N/A	
Sustained SCADA availability	99.90%	99.99%	10
Maintained timeliness of schedule publication	99.00%	99.99%	10

9.1 Dispatch accuracy dashboard

As part of the Strategic Objective Work Plan for 2019/20, we developed a Dispatch Accuracy dashboard for energy dispatch. This is a means of monitoring overall industry performance and is contained in Appendix B, along with an explanation of the methodology we used to create the dashboard.

Although the types of measures included in this dashboard have been agreed, the purpose of this year is to evaluate how well each of these illustrate industry dispatch performance. We will use this year as an opportunity to evolve the dashboard measures, the standards and metric calculation so that it provides the greatest insight. This evaluation will be performed in consultation with the Electricity Authority.

Since the last quarterly report, the following changes have been made to the dashboard, to improve the value of the information:

Measure of variability
In the previous version of the dashboard the variation was measured in terms of percentage difference from a standard (the current standard is the average of the data since January 2019). We have evolved this so that the variation is now calculated in comparison to a deviation from the standard. This provides a measure of the average variability compared to the historical variation. Changing this methodology did not materially affect the overall picture and seems a more robust method to use. The breakpoints chosen are explained in more detail in Appendix B.

Operator discretion
We have added a second measure of operation discretion. The original measure identifies all changes made when constraints are binding (such as is required following a bona fide), the new measure only captures the times discretion was used to meet the dispatch objective.

Frequency
The previous dashboard contained measures to show when frequency was “within 5% of the band limit”. After discussion, this was felt still to be far enough away from the band limit that it provided no insight. As a result, the information on the dashboard was changed to show “within 1% of the band limit”. In addition, as it was felt a better overall measure for frequency variation on the system was to track when frequency was

"outside of the band", this has been added to the dashboard; this is now the measure that is included in the metric.

Further to these changes, an addition frequency measure has been added to the dashboard that identifies the number of frequency excursions (>0.5Hz from 50Hz) each month.

HVDC modulation

We are currently discussing whether it is appropriate to include the times when the HVDC is ramping. At this stage no change has been made to the dashboard, but this will be considered as part of the dashboard's continued development.

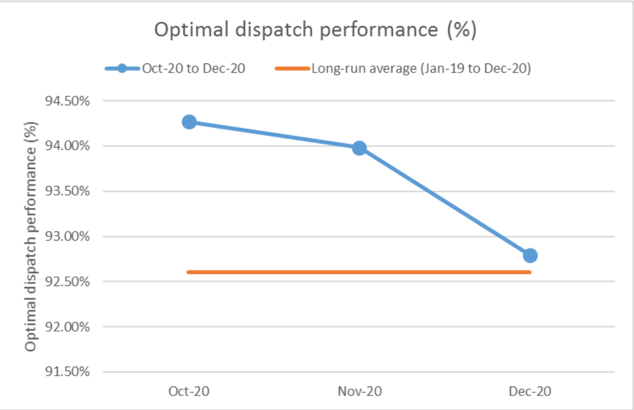
For this report we focus our comment on the current quarter, and those values in the quarter that are identified as outliers. We have included in the dashboard the data going back to the same quarter in the previous year for reference and, where appropriate, comparison, notably the recent outliers for the Optimal Dispatch measure.

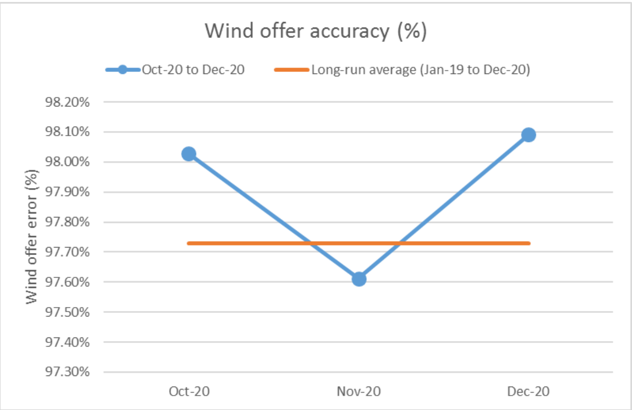
October to December 2020

- *Operator discretion to meet dispatch objective (October)*
  - The ten occurrences (higher than average) are detailed in Appendix A
  - Four of the operator discretion activities relate to switching activity during this busy period of outages
  - Three relate to activity during the CUWLP operations
  - Two were required to manage the potline at Tiwai
  - One was required to avoid Huntly breaching a resource consent
- *Frequency excursions (October)*
  - There were six occurrences during the month
  - Four of these were when a Tiwai line tripped
  - Two relate to one national incident when Huntly generation tripped on 30 October; there were frequency excursions in the North and South Islands

Optimal dispatch

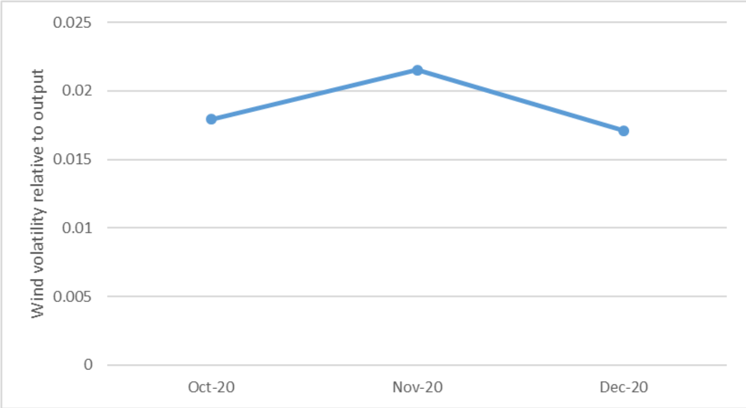
The Optimal dispatch tool has shown a fairly constant performance over the October-December quarter with the Optimal dispatch percentage above the standard[2] during this quarter. A reduction in the wind offer[3] accuracy (%) is observed in November.



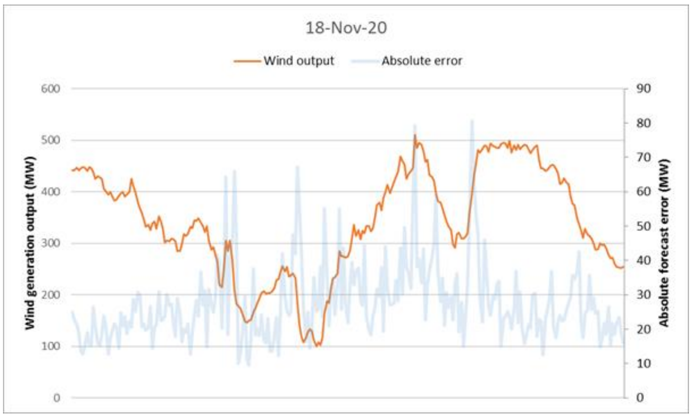


[2] This is the long-run average (Jan-19 to Dec-20).
[3] In the real-time dispatch (RTD) schedule the forecast of wind generation potential is based on the SCADA value. This implies a persistence forecast for wind generation is used in RTD based on SCADA.

The average wind output was slightly lower in November 2020 compared to October and December 2020, however there was still reasonable amount of short-term (5-minute) wind volatility, as shown in the comparison of the average 5-minute wind volatility[4] normalised against the average wind output in each of these months. November has the highest average variation relative to average monthly output.



Greater short-term wind volatility reduces the accuracy of the persistence forecast used for wind generation in the real-time dispatch process. The figure below shows the wind forecast error (blue line) as wind output changes over a day (orange line). Here we see spikes in wind forecast error during periods of more rapid changes in wind output (greater short-term volatility).



The wind offer accuracy (%) measure returned to above the long-run average in December. We will continue to monitor the wind forecast error as more wind generation comes online.

[4] Calculated as the change in output over consecutive 5-minute periods.

10 Cost-of-services reporting

We provided the Authority with a final report on the cost-of-services for financial year 4 (2019/20) on 22 December 2020.

11 Actions taken

The following table contains a full list of actions taken during Q2 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**:	• Continued to provide proactive communications and insights about supply and environmental risks (including gas), demand trends, outages, and other potential impacts of interest to market participants. • Continue to support market development initiatives by transitioning participants to the new dispatch platforms and assisting in presenting the Authority's industry workshops for the Real Time Pricing project • Completed our control-self assessment process, part of our operational risk framework, making changes to the process that we continue to evolve.
(ii) To comply with the **statutory objective work plan**:	The dispatch accuracy dashboard for energy is included as Appendix B in this report; commentary is provided for the quarter in section 9.1.
(iii) In response to participant responses to any **participant survey**:	**Feedback from the 2019-20 survey** • *"It would be good if the SO could share more info and assessment of outages in a way that gives us a heads up about potential issues"*: In our role as system operator, we have been part of the Transpower team actively briefing the industry on the CUWLP outages, and the annual HVDC outage in February.
(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

Over the quarter, South Island hydro storage was above the historical average level for only the second time since May and Lake Manapouri was spilling at the beginning of October. South Island storage continued to improve, driven largely by a prolonged period of above average inflows. North Island hydrology also rose dramatically, to 120 per cent of average. This was 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.

However, after a wet spring and long run of above average inflows in the South Island, inflows in December slowed to below average for this time of year. This resulted in national storage dropping to 98 per cent of average for this time of year, despite continued above average inflows in the North Island.

The inflows continued to be below average in 2021 such that by mid-January hydro storage was 86 per cent of average which is just above the bottom 10th percentile.

However, during this period the other noticeable change is that demand has reduced (due to longer, warmer days), so although storage is lower than average the overall effect is a low risk to security of supply.

Looking ahead to autumn and winter of 2021, when risks are expected to peak, there are two key issues/risks that are being monitored: gas supply and climate trend.

Gas supply

In October, gas production from the Pohokura gas field had been declining at a rate of around 0.5 TJ/day since early September, down from a production level of 200 TJ/day in May. In December, Pohokura confirmed 2021 will see a reduction of approximately 80 - 90 TJ/day in output. This is approximately 20 per cent of national gas production, equating to about 650 MW of thermal capacity. 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.

Security of supply modelling demonstrates the power system's ability to conserve hydro storage in an emergency scenario based on the assumption that all thermal units are running at 100 per cent of their capacity. Despite reduced gas production in 2021, analysis indicates that there will be sufficient thermal fuel for generation to meet this assumption if stored gas and Genesis' coal stockpile are drawn down, and if Methanex consumes gas at 40 per cent of its capacity. Currently there is approximately 70 days of stored gas and 6 months (plus replenishments) of coal.

The reduced gas supply has been modelled in the Electricity Risk Curves by derating the thermal generation fleet. The derating would be much more significant if stored gas in Ahuroa was lower. As such we will be monitoring the gas storage levels closely.

Climate trend

NIWA have formally announced that a La Niña event is taking place. La Niña events typically lead to increased northeasterly 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. To date, the evidence is that New Zealand is following this trend.

System operator preparedness

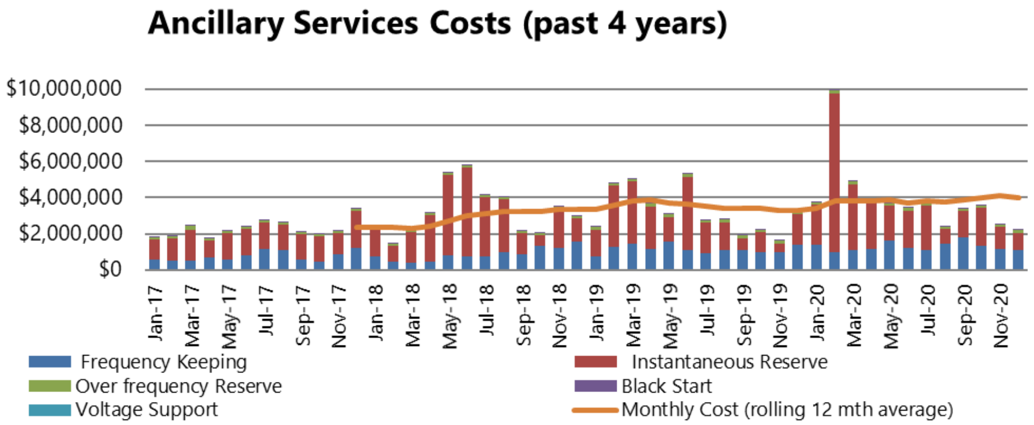
Although the electricity risk curves currently assess the security of supply risk for this winter as low, we are closely monitoring the situation and will continue to publish information and engage with stakeholders as necessary.

As part of our commitment to continuous improvement, over the last year we have undertaken a number of activities to provide assurance of our preparedness for a dry winter event:

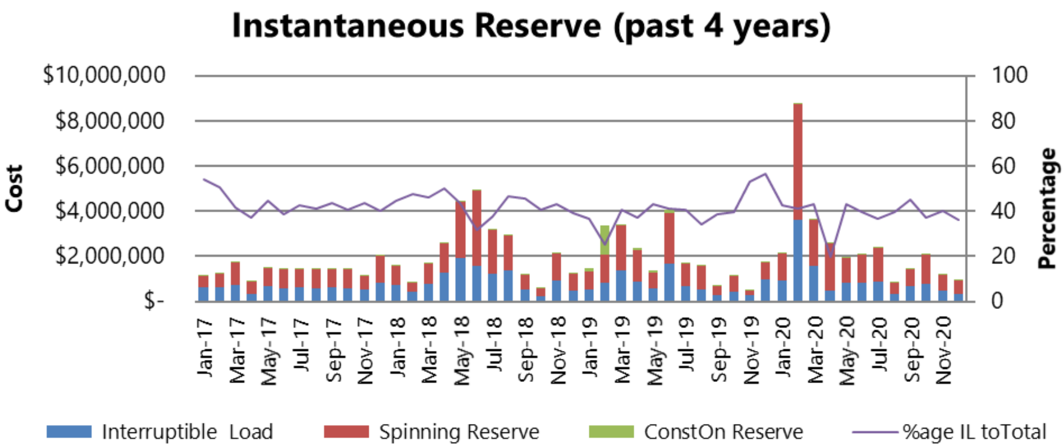
- We undertook an internal exercise to review and test our dry year processes. As a result, we shifted our processes to a Co-ordinated Incident Management System (CIMS) playbook. This outlines the activities and identifies responsibilities under a CIMS structure, both of which change as the situation progresses.
- We engaged MetService to develop an inflows forecast to provide confidence to make assessments of hydro storage seven days in advance, as is required when calling a Watch, Alert and Emergency situation.
- An external audit of the security of supply function was completed and confirmed our practices and processes were effective to manage the function successfully.
- We improved our security of supply modelling capability enabling us to run more sensitivities to uncertainties such as Methanex gas consumption during a dry year.
- We enhanced our modelling required to execute our rolling outage policy, in event of an extreme event.

Looking forward, we intend to run an additional sensitivity on our modelling to consider the impacts of increased gas demand from Methanex during a security of supply emergency.

13 Ancillary services



This quarter's ancillary service costs were $8.5 million, which is a 12 per cent decrease compared to Q1's costs of $9.7 million. Other than the initial slight increase in monthly ancillary costs in October (from September), both instantaneous reserve costs and frequency costs have gradually decreased over the quarter.

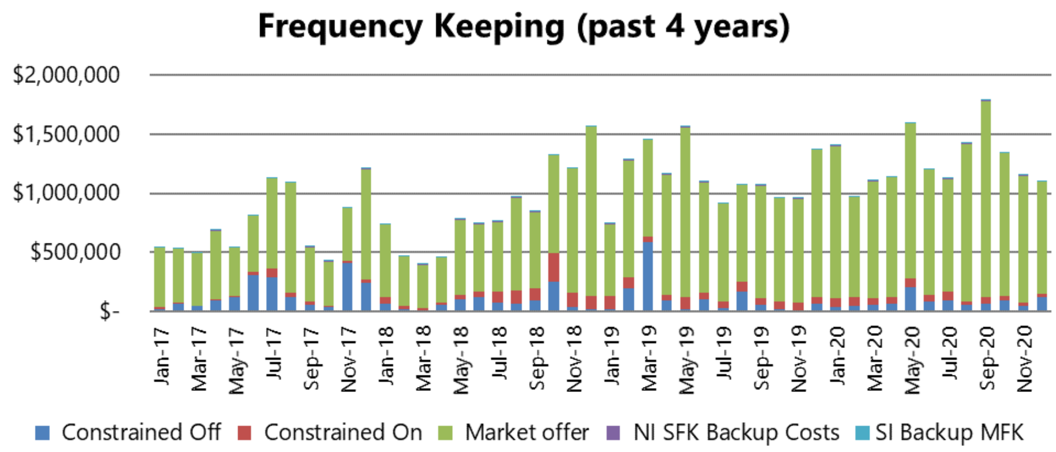


This quarter, the instantaneous reserve costs were $4.3 million, which is a small decrease of 9 per cent from the previous quarter ($4.7 million). Interruptible load costs decreased by $101k (5 per cent decrease), spinning reserves decreased by $229k (8 per cent decrease) and constrained on costs increased by $45k (82 per cent increase).

An increase in cost was seen in October. This is a result of both the overall quantity of reserve procured increasing slightly, and the average price of North and South Island Fast Instantaneous Reserve (FIR) being around 70 per cent higher than the previous month. Both quantities and prices were fairly steady over the month with no dominating periods of high reserve costs.

In the latter part of November, 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.

Costs dropped further in December as there was a noticeable drop in both the quantity of reserves as well as the price at which they were procured.

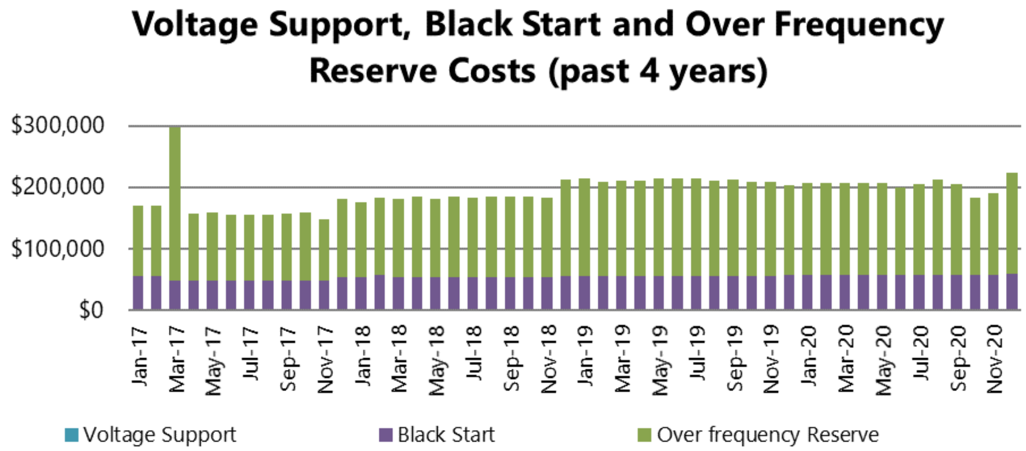


This quarter the frequency keeping costs were $3.6 million, a 17 per cent decrease to the previous quarter's costs of $4.3 million.

In October, the offer price volatility decreased compared to September and prices returned to more normal levels. Tekapo was islanded for fewer days this month than September, and consequently Tekapo A frequency keeping costs also reduced.

The decrease in costs in November was partly due to the changing mix of frequency keeping providers with improved South Island hydro levels.

The frequency keeping cost fell slightly in December as North Island hydro storage improved.

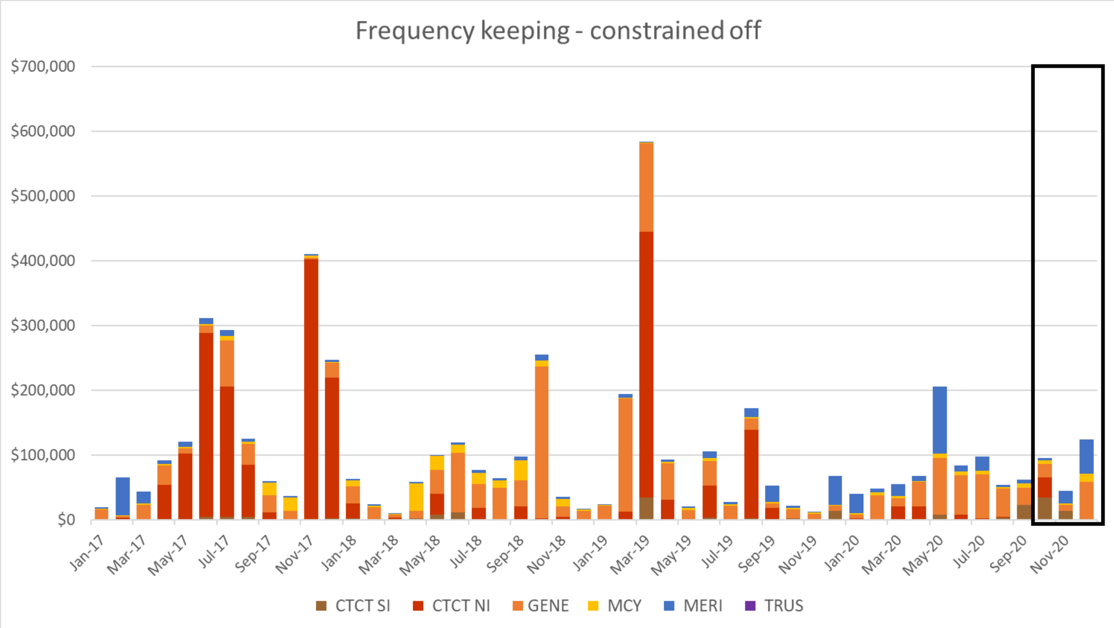


This quarter, there was some variance to the over frequency costs. In October and November this was due to a proportion of the procured equipment being unavailable at different times. New over frequency reserve contracts came into effect on 1 December causing an increase in the monthly costs. The black start costs were $58k for October and November and increased in December due to new South Island contracts and annual CPI adjustments to North Island contracts. There are no voltage support costs as we do not currently procure this service.

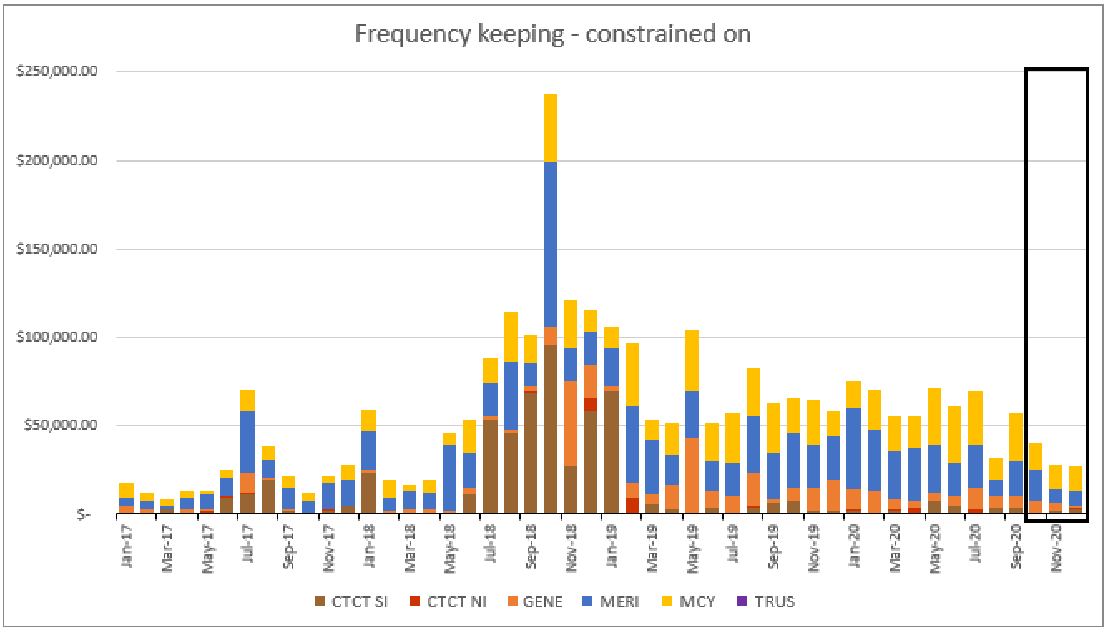
13.1 Constrained on/off costs

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

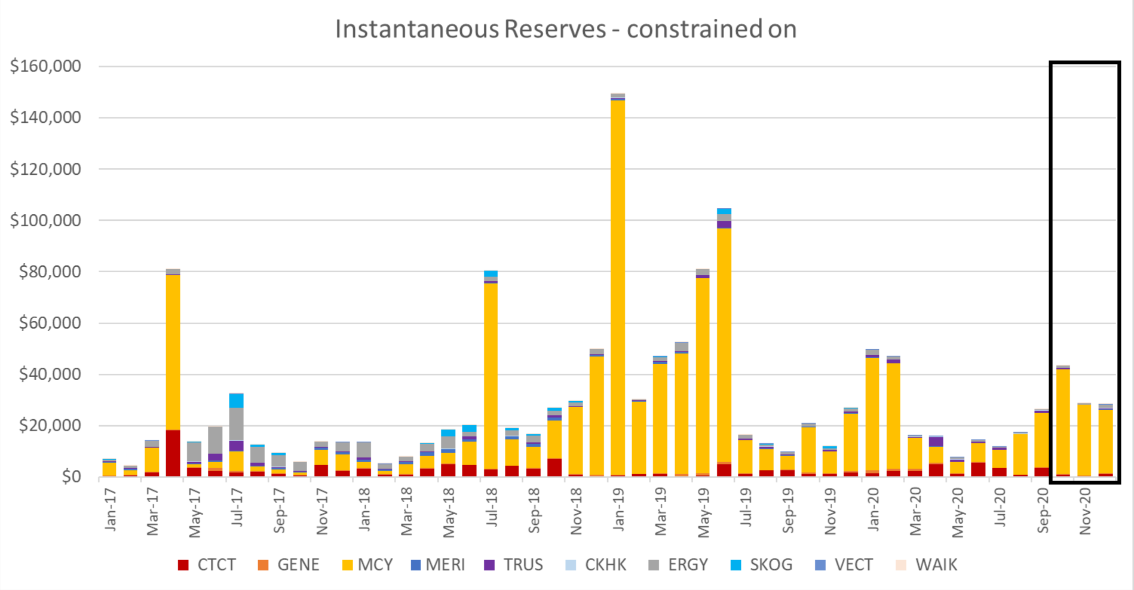


For 2020/21 Q2, the frequency keeping constrained off costs increased on the previous quarter. The costs were tracking down for the quarter until the costs in December increased significantly.



For 2020/21 Q2, the frequency keeping constrained on cost decreased from the previous quarter. This decrease was accompanied by improved hydro storage in both the North and South Islands.

Instantaneous Reserves



For 2020/21 Q2, the instantaneous reserves constrained on costs were higher than the previous quarter. This was strongly influenced by higher FIR prices in October. The instantaneous reserves constrained on costs were slightly higher this quarter. The costs reflect the need to support the HVDC during northward flow.

14 Commissioning and Testing

Generation testing and commissioning and model changes

Waipipi windfarm started injecting into the power system in November. Commissioning of the turbines also started and will carry on through until February 2021. 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 risk for the full duration of commissioning but should have minimal impact on reserves.

Ngawha B connected to the power system in December and commenced commissioning. Like Waipipi, initially the generator was treated as both a secondary contingent and extended contingent risk. The secondary contingent risk was removed after testing was completed over the summer break. Ngawha B will remain a secondary extended contingent risk until the completion of commissioning.

We continue to work with Mercury to finalise plans for commissioning Turitea North and South windfarm once they are ready to be connected to the power system.

15 Operational and system events

October

High workloads were experienced in the control centres as the warm weather and large number of outages combined to introduce complexities in managing power system stability.

November

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.

December

High workloads continued right up until the holiday break. Only one small interruption occurred when a crane boom hit a Powerco line resulting in tripping of a transformer at Waverley on 21 December and loss of 3.2 MW.

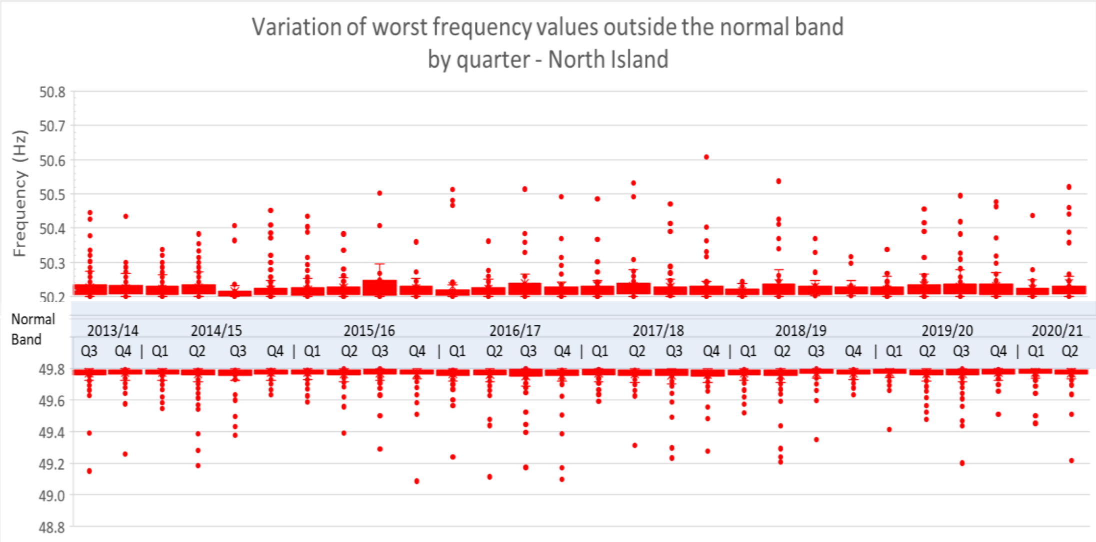
With the warmer temperatures and relatively low loads, control rooms were kept busy managing voltages, particularly in the upper North Island.

16 Frequency fluctuations

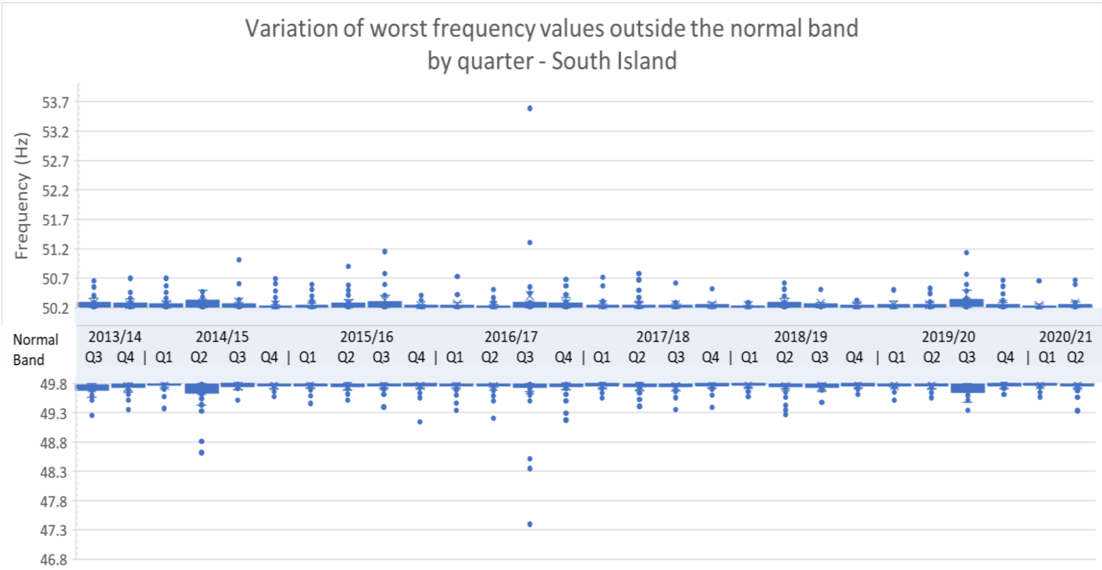
16.1 Maintain frequency in normal band (Frequency value)

The following charts show the distribution of the worst frequency excursion outside the normal band (49.8 to 50.2 Hz) by quarter since July 2014, including the reporting period.

North Island



South Island

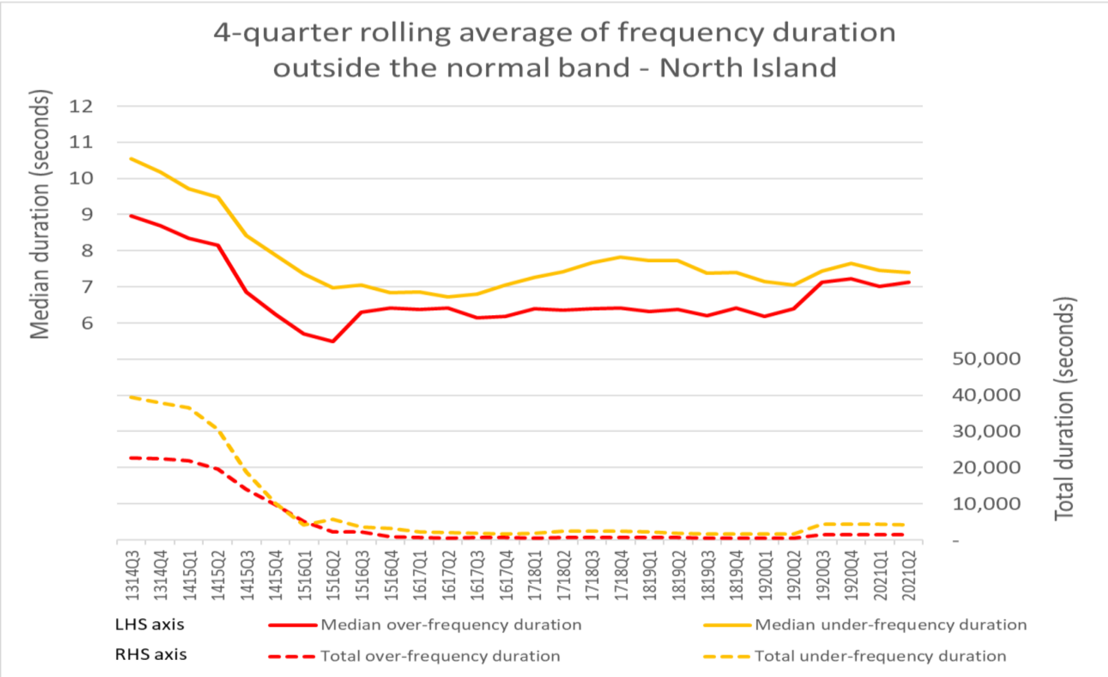


Note: These box and whisker charts show the distribution of data. The “box” represents the distribution of the middle 50% of the data, the “whiskers” indicate variability, and outliers are shown as single data points.

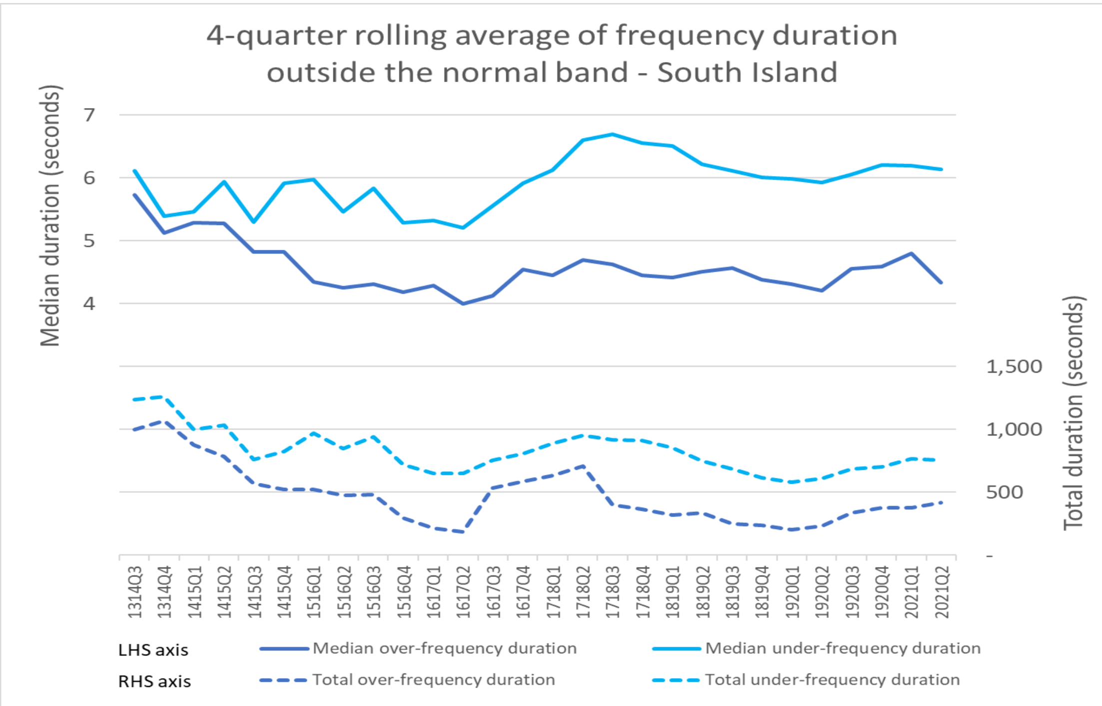
16.2 Recover quickly from a fluctuation (Time)

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



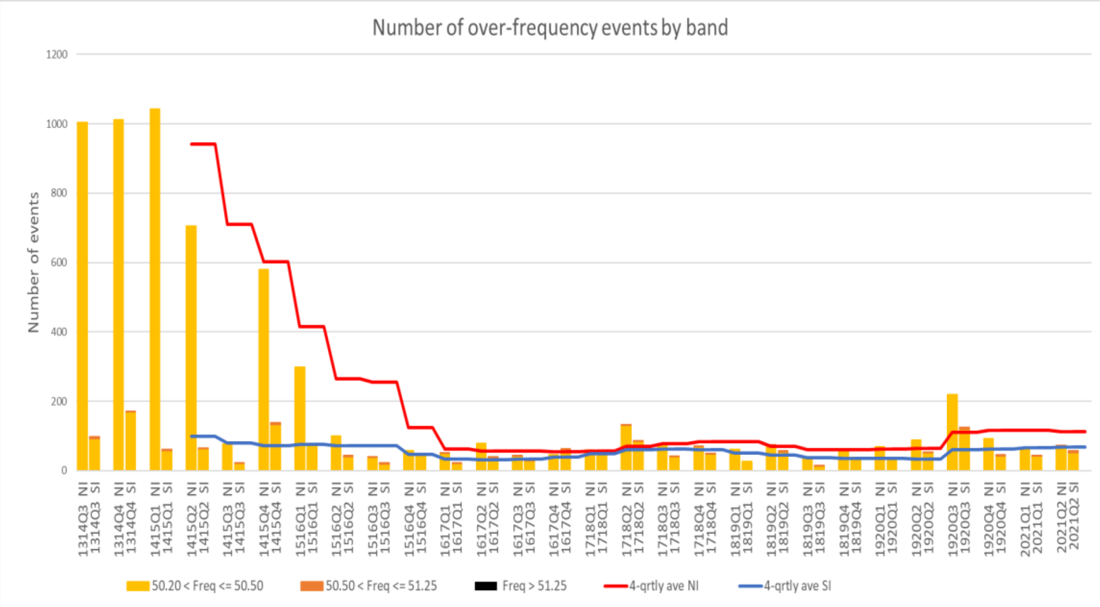
South Island



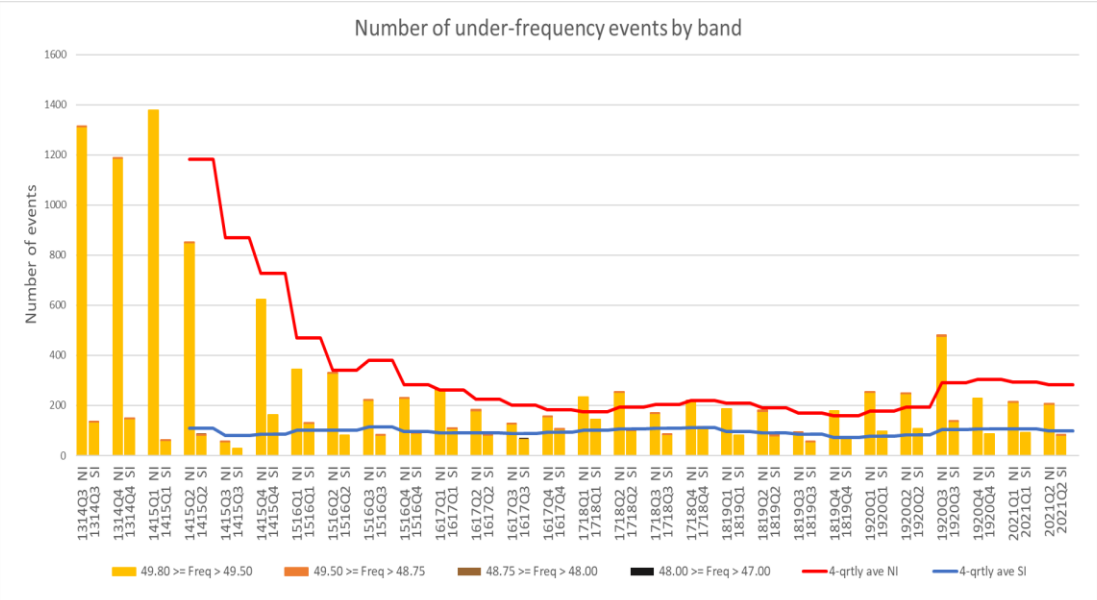
16.3 Manage frequency and limit rate of occurrences during momentary fluctuations (Number)

The following charts show the number of momentary fluctuations outside the frequency normal band, grouped by frequency band, for each quarter since 2014. The 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	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Demand Allocation Notice	-	-	-	-	-	-	-	-	-	-	-	-
Grid Emergency Notice	-	-	1	-	-	1	-	-	-	1	-	2
Warning Notice	1	-	2	-	-	-	-	-	-	-	-	-
Customer Advice Notice	6	21	14	13	10	13	11	15	9	6	12	10

19 Grid emergencies

The following table shows grid emergencies declared by Transpower as system operator from October to December 2020.

Date	Time	Summary Details	Island
14/10/20	17:36	A grid emergency was declared to allow a grid reconfiguration in the North Canterbury area. This was required due to a lightning storm increasing the risk of a double circuit contingency on the 220 kV Islington – Waipara – Culverdon – Kikiwa circuits 2 & 3.	S
12/12/20	08:27	A grid emergency was declared to assist with restoration of supply following a loss to Arthurs Pass, Castle Hill, Otira, and Hokitika substation due to multiple circuits tripping.	S
27/12/20	10:41	A grid emergency was declared to assist with restoration of connection to Tekapo A substation following the tripping of the sole 110 kV Albury – Tekapo A circuit.	S

Appendix A: Discretion

October

Event Date & Time	Event Description
06-Oct-2020 07:29	ARG1101 BRR0 Discretion Max : 0 Last Dispatched MW: 10 : For switching during ARG_KIK_1 outage
06-Oct-2020 10:59	ARG1101 BRR0 Discretion Max : 0 Last Dispatched MW: 11 : For switching during ARG_KIK_1 outage
07-Oct-2020 07:25	ARG1101 BRR0 Discretion Max : 0 Last Dispatched MW: 11 : For switching during ARG_BLN_1 outage
09-Oct-2020 09:12	MAN2201 MAN0 Discretion Max : 535 Last Dispatched MW: 704.85. : TWI 3 Potline returning. Backing off MAN to provide capacity to manage the potline
09-Oct-2020 09:15	MAN2201 MAN0 Discretion Max : 590 Last Dispatched MW: 535 : TWI 3 Potline returning. Backing off MAN to provide capacity to manage the potline
09-Oct-2020 13:23	ARG1101 BRR0 Discretion Max : 0 Last Dispatched MW: 11 : Switching to return ARG_BLN to service
14-Oct-2020 01:22	HLY2201 HLY5 Discretion Min : 182 Last Dispatched MW: 182 : Claimed 13.82a exemption to avoid breaching resource consent. Security Coordinator advised that they will be required over the morning peak.
27-Oct-2020 20:29	MAN2201 MAN0 Discretion Max : 780 Last Dispatched MW: 788 : NMA_TWI2 static violation
30-Oct-2020 08:34	NMA0331 WHL0 Discretion Max : 27 Last Dispatched MW: 34.17 : RTCA violation for NMA_TWI2
30-Oct-2020 08:18	MAN2201 MAN0 Discretion Max : 733 Last Dispatched MW: 738 : RTCA violation NMA_TWI2

November

Event Date & Time	Event 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.

December

Event Date & Time	Event Description
	None

Appendix B: Dispatch Accuracy Dashboard

Same quarter in 2019/20

This quarter 2020/21

Using deviation as the breakpoints			2019 October	November	December	2020 January	February	March	April	May	June	July	August	September	October	November	December
Operator discretion applied	Total number of instances (5-minute dispatches) where operator interventions depart from the dispatch schedule to ensure the dispatch objective is met.	100% binding	489	546	705	550	756	641	498	586	718	791	416	599	540	515	493
	Instances where the system operator has applied discretion under 13.70 of the Code to meet dispatch objective		1	2	8	2	4	4	-	1	3	3	-	4	10	3	-
Frequency keeper (MW)	Average absolute deviation (MW) from frequency keeper dispatch point. A movement of frequency keeping units away from their setpoint suggests greater variability in the system, but can also indicate the need	NI	6.56	6.63	6.83	7.63	7.01	6.90	6.80	6.87	6.97	7.01	7.06	7.11	7.06	6.89	7.11
		SI	6.00	6.23	6.28	6.49	6.84	6.33	6.64	6.41	6.80	6.51	6.53	6.83	6.62	6.74	6.50
Time error (s)	Average absolute daily time error (s) indicates imbalance between generation and load, a reflection of imperfect dispatch	NI	0.2198	0.2033	0.1996	0.2410	0.2340	0.2455	0.2843	0.2277	0.2768	0.2368	0.2018	0.2064	0.1815	0.2092	0.1777
		SI	0.1989	0.2086	0.2137	0.1967	0.2309	0.2217	0.1923	0.2323	0.2845	0.2507	0.1979	0.1973	0.1818	0.1947	0.1872
Frequency excursions	Number of frequency excursions (>0.5Hz from 50Hz)		1	2	-	1	4	5	1	1	1	1	1	-	6	3	-
FK within 1% of band limit	% of time frequency keepers spend near to or exceeding their regulation limits indicates the need to redispatch.	NI	**2.0%**	**2.1%**	**2.3%**	**3.7%**	2.9%	3.7%	1.8%	2.4%	3.2%	3.1%	3.7%	3.5%	2.8%	2.66%	2.87%
		SI	**2.9%**	**3.0%**	**3.3%**	**2.8%**	3.9%		2.7%	3.5%	4.3%	4.0%	4.6%	4.8%	3.9%	3.85%	4.16%
FK outside of band limit	% of time frequency keepers spend outside their regulation limits	NI	**0.03%**	**0.02%**	**0.00%**	**0.81%**	0.12%	0.54%	0.05%	0.00%	0.04%	0.11%	0.02%	0.02%	0.01%	0.00%	0.01%
		SI	**0.01%**	**0.01%**	**0.00%**	**0.03%**	0.01%		0.00%	0.00%	0.01%	0.00%	0.01%	0.00%	0.00%	0.01%	0.00%
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.		10.77%	10.91%	10.46%	**8.37%**	12.79%	10.37%	6.92%	13.90%	9.62%	14.65%	9.83%	9.72%	8.19%	8.50%	7.42%
	Total Monthly Generation	MWh	3,621,216	3,418,901	3,475,825	**3,501,768**	3,329,074	3,407,184	2,931,637	3,629,018	3,710,599	4,006,808	3,861,813	3,671,507	3,642,908	3,396,766	3,429,779
Constrained on energy-Total	Total constrained on - All sources	MWh	25,683	29,286	31,997	**23,641**	28,565	24,912	32,088	26,519	24,247	23,649	26,426	24,579	24,672	23,347	18,499
		% of all generation	**0.71%**	**0.86%**	**0.92%**	**0.68%**	0.86%	0.73%	1.09%	0.73%	0.65%	0.59%	0.68%	0.67%	0.68%	0.69%	0.54%
		$	534,069	609,542	517,746	**365,863**	468,969	304,255	303,542	491,296	488,575	712,042	379,543	503,196	399,820	292,501	455,009
Constrained on energy ($) - Frequency keeping	Total constrained on $ due to frequency keeping (within band is attributable to SO)	$	65,890	64,505	58,343	**75,173**	70,074	52,492	55,553	71,518	61,301	69,715	31,973	57,712	40,822	28,503	27,411
Optimal Dispatch (%)	Compares the average impact of a perfect foresight case against dispatch solutions. Indicates impact of wind offer, load forecast and PSD accuracy.	%	91.59%	91.34%	88.30%	**93.35%**	90.62%	91.74%	87.29%	90.77%	92.78%	93.19%	94.38%	94.34%	94.27%	94.0%	92.8%
Dispatch load accuracy error (%)	Average absolute difference between forecast generation (load plus losses, including PSD) and actual generation relative to the average actual generation	%	99.50%	99.48%	99.51%	**99.62%**	99.54%	99.57%	99.52%	99.52%	99.56%	99.59%	99.62%	99.62%	99.62%	99.6%	99.6%
Wind offer accuracy (%)	Average absolute difference between persistence wind offer (based on 5mins prior) and the actual wind output relative to the average wind output	%	97.71%	97.96%	97.71%	**97.93%**	97.82%	97.50%	97.81%	97.36%	97.81%	97.82%	97.85%	98.14%	98.03%	97.6%	98.1%
	Metric calculation rows	FK outside	3	3	3	1	3	1	3	3	3	3	3	3	3	3	3
		Constraine	3	2	1	3	2	3	1	3	3	3	3	3	3	3	3
		Optimal Disp	2	2	1	3	1	2	1	2	3	3	3	3	3	3	3
Dispatch accuracy %	**Metric out of 3 (3 is best possible result)**		**2.7**	**2.3**	**1.7**	**2.3**	2.0	2.0	1.7	2.7	3.0	3.0	3.0	3.0	3.0	3.0	3.0

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

NOTE 2: Summary data for "FK outside of band limit" is not shown for the South Island in March 2020. The data collected for this month has missing values for a number of dates which meant the measure could not be calculated.

Understanding the 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. During 2020/21 we will monitor how well this metric represents performance, with the purpose of baselining a target and metric as part of the 2021/22 performance metrics.

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

[5]

Metric

The measures that contribute towards the metric are:

- FK outside of band limit [6]
- 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:

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

[5]

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 Dispatc	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**

[5] 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
[6] 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