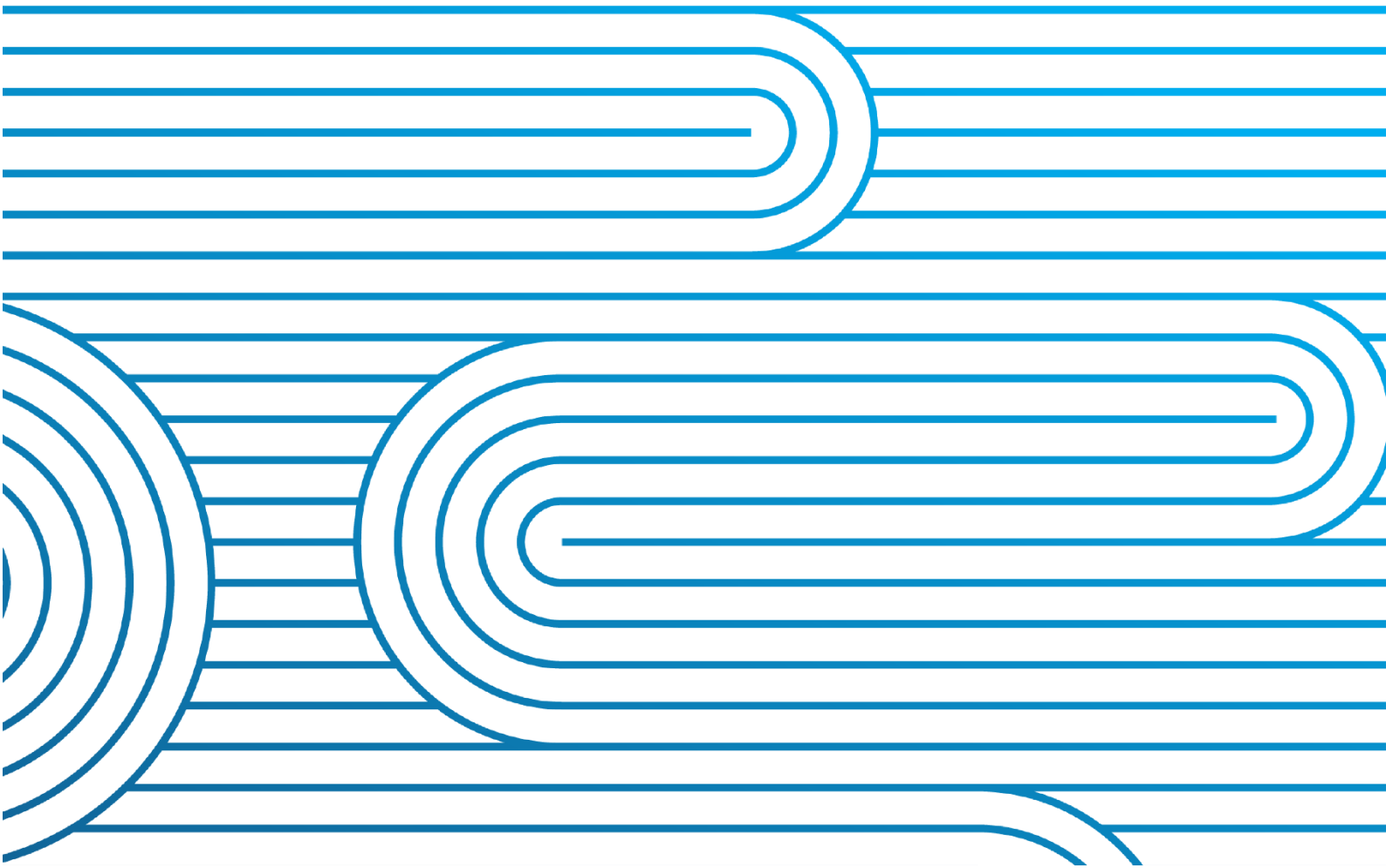
TRANSPOWER

Quarterly System Operator and system performance report

For the Electricity Authority

January to March 2022



Report Purpose

This report is Transpower's review of its performance as System Operator for Q3 2021/22 (January to March 2022), in accordance with clause 3.14 of the Electricity Industry Participation Code 2010 (the Code).

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

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

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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 (January to March 2022)

SOSPA deliverables

- We kicked off a series of internal workshops in February 2022, as a part of our KPI refresh initiative. These aim to gather and prioritise views about what matters most in delivering a successful System Operator service day-to-day.
- On 1 April, we delivered the 2020/21 SOWP deliverable which set out the plan of what we will deliver for the remainder of this year (FY21/22), FY22/23 and FY23/24.

Security of Supply and market information

- 2022 saw a dry start to the year with the lowest January inflows on record. This was in-line with NIWA predictions and the current La Niña climate event. Despite some heavy rainfall events in February, national hydro storage sits below average for the time of year as of 10 April 2022 (at 82%).
- Lake levels at Manapōuri and Te Anau now sit in their low operating ranges. As a result, output from these lakes is limited. This has been causing some voltage issues overnight which have been being managed by the National Coordination Centre.
- The System Operator has undertaken system security studies to determine how the system might look if hydro levels continue to decline, and requested an urgent grid reconfiguration under the Code. This grid reconfiguration will remove the risk of load management under specific set of conditions if Manapōuri cannot generate. Studies are ongoing.
- Contact Energy has advised that the Taranaki Combined Cycle (TCC) will operate with a 2,000 hour limitation, limiting the number of GWh the unit will produce over the winter ahead. Despite this, the unit can run in open cycle mode without limitation. The System Operator markets team will be updating the Electricity Risk Curves to reflect this.

Projects and TAS work

- **Real Time Pricing (RTP):** Phase 2 was successfully deployed in March 2022 with no defects identified to date. Planning and preparation are now underway for Phase 3, which will implement the primary scope of this project. Following recent re-forecasting work it is anticipated that there will be need for additional budget and the requirement for an extension to some milestones. A change request has been submitted to the Electricity Authority.
- **AUFLS customer portal:** The Asset Capability Statement (ACS) application of the Customer Portal went live on 8 December 2021. Roll out support was complete by the end of January 2022, and the legacy ACS is no longer available.

- **Load Forecast as a Service:** The Load Forecast as a Service procurement process was completed at the end of January 2022, with Tesla selected as the supplier. The service was launched into the control room on the 24 February 2022 and is now the primary forecast used in real-time.
- **Future Security and Resilience (FSR) programme:** The final phase 1 report and phase 2 draft roadmap were delivered to the Authority mid-January 2022. The attention of this programme is now turning to scoping the first year of work, which relates to updating technical requirements in the Code and other associated documents.
- **TAS work relating to Battery Offering Reserves (TAS 100):** Following the completion of internal System Operator testing in December 2021, the project team have been supporting NZX with their internal testing from January to March 2022.
- **December 2019 UTS (TAS 101):** The resettlement process was complete on 20 January 2022 and the Closure Report for this work was sent to the Authority on 28 January 2022.

Risk and Assurance

- All August 9 Transpower and Authority investigation actions, due by November 2021, are complete; assurance reports for all completed actions were tabled to ensure completeness prior to being closed out. Attention has now turned to remaining, longer-term actions and on supporting compliance investigations.
- An internal COVID-19 policy has been implemented and Control Rooms moved quickly to align protocols with the national traffic light framework and three phase approach to operating under “Red Light”. Consideration is now moving to ensuring appropriate business continuity processes are in place ahead of teams returning to offices.
- The Reserve Management Tool (RMT) Operational Change audit has concluded with three recommendations for implementation relating to improving governance within the Change Management Board, training and process improvement on change registers.
- The RFP for consultant support for our Operational Excellence programme closed early-February 2022 and a vendor has now been identified for this programme; this programme seeks to review our control room operating practices.
- We closed one Conflict of Interest item in March; a System Operator Principal Market Advisor participated in a Transpower demand response working group which has now concluded (Conflict of Interest ID 31).
- We did not report any System Operator breaches this quarter. However, the Authority issued a fact-finding letter to the System Operator on 24 March 2022, which noted a breach alleged against the System Operator by another participant. A response denying this breach and providing an explanation of the circumstances has been returned to the Authority.
- We engaged Deloitte to conduct an audit of the System Operator’s end-to-end breach process. A final Summary of Findings was delivered in early January 2022 and confirmed a clean audit with no recommendations. We have

tentatively agreed with Deloitte that the independence audit for the 2022/2023 financial year will focus on security of supply.

- We have seen high outage numbers throughout February and March. A small number of short notice cancellations or delays to outages, as work crews were impacted by COVID-19, were seen in March. We have also seen some outage changes as a result of the low hydro situation in Southland.
- April's NZGB report forecasts two N-1-G generation balance shortfalls forecast for the base scenario on 3 May and 8 August 2022. Between early May and late August there are a further 18 dates where the N-1-G balance is less than 100 MW and eight of these dates have balances below 50 MW. These periods use the record 29 June and 9 August 2021 demands in their calculations.

Generation commissioning

- Mercury Energy's 119 MW Turitea North windfarm is fully commissioned.
- We are treating two 10-30 MW solar farms as 'committed' projects despite not meeting all pre-requisites for System Operator involvement. Both have an intention to connect in the next 12 – 18 months.
- We will be seeking an opinion from the Authority on an interpretation of Point Of Connection, as this is becoming a point of contention with some generation connecting within distribution networks. The outcome of the interpretation from the Authority has implications for Asset Owner Performance Obligations.

Incidents

- None to report this quarter.

Recent initiatives

- **Industry Consultation on the Security of Supply Forecasting and Information Policy (SOSFIP) and Emergency Management Policy (EMP):** A consultation on changes to the SOSFIP and EMP was published on 29 March 2022. The consultation has been reviewed by the Authority and will be open for four weeks. Responses will be collated, for the Authority to make a decision on changes to be implement in the SOSFIP and EMP.

System Operator performance

1 Customers and other relationships

KPI refresh

We kicked off a series of internal workshops in February 2022, with the aim of gathering and prioritising views about what matters most in delivering a successful System Operator service day-to-day. The first workshops provided us with some provisional critical success factors and indicative external outcomes which feed into a collaborative process between the System Operator and Electricity Authority. The latest workshops have identified possible performance measures against the critical success factors, these will be used as a resource by the pilot teams when they trial the new methodology for the areas of managing system events and project delivery.

On 1 April, we delivered the 2020/21 SOWP deliverable which set out the plan of what we will deliver for the remainder of this year (FY21/22), FY22/23 and FY23/24.

2 Risk & Assurance

COVID-19

An internal COVID-19 policy has been implemented. Control Rooms moved quickly to align protocols with the national traffic light framework and three phase approach to operating under “Red Light”. N95 equivalent masks and rapid antigen tests have been sourced and these, alongside associated training and processes, have been distributed to teams. Consideration is now moving to ensuring appropriate business continuity processes are in place ahead of wider teams returning to offices.

With a series of individuals impacted over the month by COVID-19, we have been calling on operators who are close household contacts to positive cases, but are RAT testing negative, to work shifts under our exemption as a critical service. In these situations, the operator works from the ancillary control desk to minimise risk. We are awaiting advice from the Ministry of Health regarding the process to seek exemption approval to roster RAT positive but asymptomatic operators, should this be required as a last resort.

An internal COVID-19 Incident Management Team (IMT) and the internal Health and Safety team are providing support with contingency planning for worst case scenarios. These are aiding in the development of a longer-term plan for working through pandemic situations.

9 August generation shortfall event

All Transpower and Authority investigation actions due November 2021 are complete; assurance reports for all completed actions were tabled to ensure completeness prior

to being closed out. Attention has now turned to remaining, longer-term actions and on supporting compliance investigations.

Thursday 26 May has been set for the recommended industry exercise (generation shortfall scenario), and communications to participants began mid-March 2022.

Security of supply

2022 saw a dry start to the year with the lowest January inflows on record. This was in-line with NIWA predictions and the current La Niña climate event. Despite some heavy rainfall events in February, national hydro storage sits below average for the time of year as of 10 April 2022 (at 82%).

Lakes Manapōuri and Te Anau are currently sitting below their operating ranges. This is limiting output and leading to some voltage issues overnight, which are being managed by the National Coordination Centre (NCC). Lakes Tekapo and Pukaki on the other hand are at 86% and 79% of average for the time of year. Collectively these lakes make up 70% of national hydro storage capacity.

The System Operator is undertaking system security studies to determine how the system might look if hydro levels continue to decline.

More on security of supply can be found under section 12 in this report.

Business Assurance audits

The Reserve Management Tool (RMT) Operational Change has concluded with three recommendations for implementation relating to improving governance within the Change Management Board, training, and process improvement on change registers.

The Managing Conditional Offers audit is near completion. The Secondary Risk audit is underway. The remaining audit on Outage Block Mapping will be completed before the end of the financial year in accordance with the SOSPA.

Critical controls for the Operations risk bowtie

Plans are underway to undertake a mid-year Control Self-Assessment round in April 2022 for five critical controls. This aims to provide assurance that action is being taken to lift general effectiveness.

Operational Excellence

The RFP for consultant support for our Operational Excellence programme closed in early-February 2022 and a vendor has now been identified for this programme. Work is on track to initiate the engagement ahead of the end of April 2022.

This programme will review control room operating practices including processes, change management practices, training, resourcing and behaviours, to assure this part of operation is best prepared for a rapidly evolving future.

3 Compliance

January

We did not report any additional System Operator breaches in January (one was covered in the previous quarterly report).

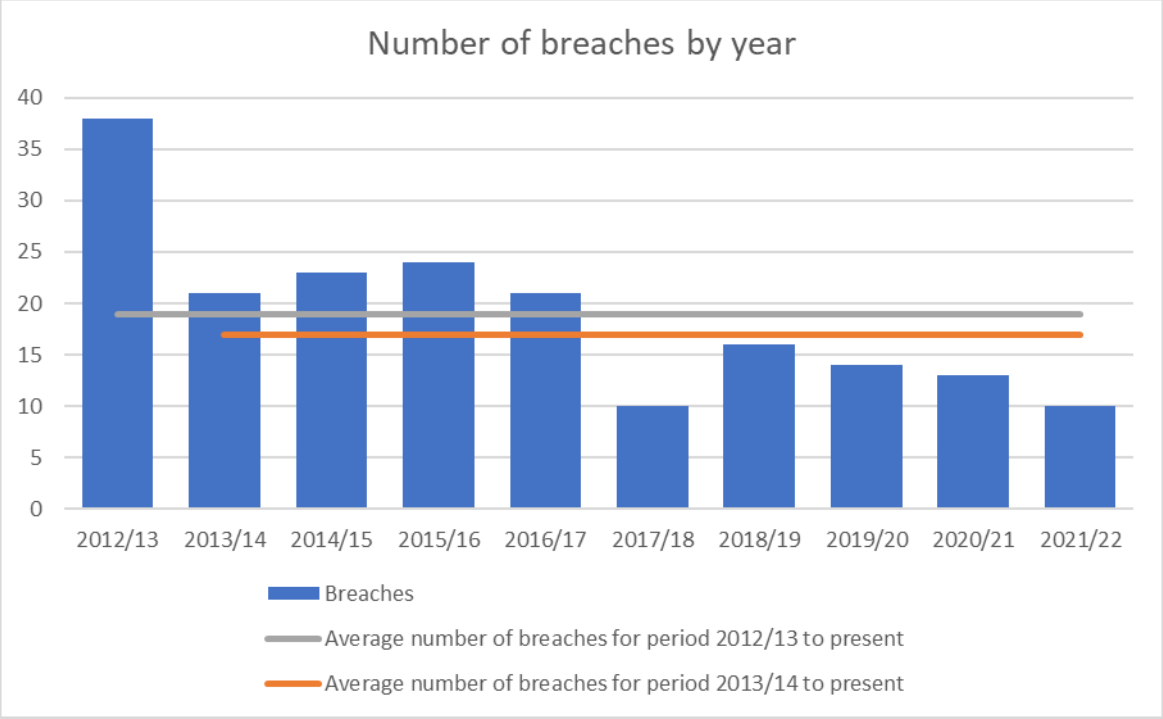
February

We did not report any System Operator breaches in February.

March

We did not report any System Operator breaches in March. However, the Authority issued a fact-finding letter to the System Operator on 24 March 2022, which related to a breach alleged against the System Operator by another participant. The alleged breach is that the System Operator had un-disclosed disclosure information in its possession and may have shared that information with selected participants prior to an industry briefing held by the System Operator on 22 March 2022. A response denying this breach and providing an explanation of the circumstances, which relate to a voltage stability issue in the lower South Island, was returned to the Authority.

We have fifteen outstanding breaches with the Authority compliance team.



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 register (Register). These issues are being actively managed in accordance with our policy for managing conflicts of interest.

We closed one Conflict of Interest item in March; a System Operator Principal Market Advisor participated in a Transpower demand response working group which has now concluded (Conflict of Interest ID 31).

There are five open items in the Register that are being actively managed.

System Operator Open Conflict of Interest Issues		
ID	Title	Managed by
29	**Preparing the Net Benefit test – System Operator involvement:** The System Operator is reviewing how it can provide information for use by the grid owner undertaking a Net Benefit Test.	Operations Planning Manager
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
41	**General relationship situation:** This is a general item that will remain permanently open to cover all potential conflicts of interest arising under a relationship situation. This item documents the actions necessary to prevent an actual conflict arising and will be monitored by the SO Compliance & Impartiality Manager to ensure their continued effectiveness.	SO Compliance & Impartiality Manager
42	**Mercury KPO upgrade:** The Power Systems Engineer assigned to manage the KPO upgrade previously worked at Mercury. The employee will provide input into the commissioning/testing documentation and will prepare the final compliance documentation for SO sign-off. Controls have been implemented, including management oversight and sign-off of all commissioning/testing documentation.	Power Systems Engineering Assurance Manager

4.1 Independence recommendations update

Transpower's Risk & Assurance team engaged Deloitte to conduct an audit of the System Operator's end-to-end breach process. The audit related to the System Operator's inherent independence threat around monitoring the Grid Owner's compliance with the Code. Deloitte commenced the audit in June 2021 and delivered a final Summary of Findings to the System Operator in early January 2022 which has been provided to the Authority. The Summary of Findings confirmed a clean audit with no recommendations.

The System Operator held a kick-off meeting with Deloitte on 11 April to scope the 2022 System Operator independence audit. We have tentatively agreed with Deloitte that the independence audit for the 2022/2023 financial year will focus on security of supply.

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)
Phase 2 was successfully deployed in March 2022 with no defects identified to date. Planning and preparation are now underway for Phase 3, which will implement the primary scope of this project. Code amendment reviews with the Authority are nearing completion, and System Operator Policy Statement updates are in progress. In addition, planning in conjunction with the Electricity Authority for ongoing industry engagement, and preparation for the operational impacts of Phase 3 deployment to Transpower's Operations division are underway.

Following re-forecasting activity, the Real Time Pricing project is now forecasting the need for additional budget and the requirement for an extension to some milestones resulting from higher than anticipated rates of resource turnover, rate increases in a heated market caused by closed boarders, and additional unbudgeted workload. Change request RTP CR007 has been submitted to the Electricity Authority. This will be discussed at the projects joint steering committee meeting in mid-April.

ACS Customer Portal Launch
The Asset Capability Statement (ACS) application of the Customer Portal went live on 8 December 2021, following several external training workshops with industry participants. Drop-in sessions for participants, offering one-on-one support, were available between 13-15 December 2021 and during the second half of January 2022. Roll out support was complete as of the end of January 2022 and the legacy ACS is no longer available.

Load Forecast as a Service Launch
The Load Forecast as a Service procurement process was completed at the end of January 2022, with Tesla being selected as the supplier and contracted from 1 February 2022. The service was successfully launched into the control room on the 24 February 2022 and is now the primary forecast used in real-time. Transpower has retained, and will continue to maintain, the old forecasting tool to provide redundancy in the unlikely event that there is a sustained issue with the Tesla Forecast.

5.2 Other projects and initiatives

Industry consultation on the Security of Supply Forecasting and Information Policy (SOSFIP) and Emergency Management Policy (EMP)
A consultation on changes to the SOSFIP and EMP was published on 29 March 2022. These are System Operator policy documents incorporated by reference into the Code. They set out how the SO prepares and publishes information regarding national hydro storage, including the Electricity Risk Curves (ERCs) which are the trigger for policy mechanisms such as Official Conservation Campaigns and the Customer

Compensation Scheme. This consultation follows the MartinJenkins 2021 dry year review and proposes to:

- Request feedback on various ways treat gas reallocation and electricity demand response in the modelling by requiring evidence of formal contracts to support assumptions
- Publish risk curves but not "status" curves to avoid current industry confusion caused by publishing two sets of curves, requiring a medium probability demand forecast to be used in analysis
- Make other minor clarifications in terminology and triggers for daily reporting

The consultation has been reviewed by the Authority and will be open for 4 weeks. Responses will be collated for the Authority to make a decision on changes to be implement in the SOSFIP and EMP.

Continuous Business Improvement Initiatives

Initiative	Activity Completed	Improvement Implementation
Business Process Modelling Tooling Improvements	**Current State Evaluation** • Operations leads and manages development and maintenance of the Operations Business Model and affiliated supporting outputs • The current business modelling practice is very manual using basic, generic software including Microsoft Visio and Excel • Business modelling outputs are not easily accessible, visible and traceable, especially to infrequent users. These outputs are prone to loss and version discrepancies as they are stored across multiple repositories Alternative tooling evaluation completed February 2022 involved: • Capturing detailed user requirements • Identifying potential options for a business process modelling solution (i.e., long list). • Conducting a brief trial of the solutions. • Assessed options against user requirements. • Evaluating key solution strengths and weaknesses • Getting architectural evaluation completed • Recommending a business process modelling tooling option	A tool has been selected and a business case underway to implement a more fit for purpose Business Process Modelling capability for Operations. This will introduce the following benefits: • Provide a user-friendly layout with significant collaboration capabilities to drive adoption and engagement from business analysts, information management specialists, process owners and performers. • Introduce a multi-dimensional tool that is easier to navigate up, down and horizontally in a seamless way allowing users to easily access the information they need. The outputs produced also get allocated to the Process Hierarchy Model creating a centre of process excellence • Provide a more robust process architecture capability which can be easily created visually and maintained. This will enable us to respond to changing needs efficiently and ensure the process hierarchy function does not get out of date, lose credibility and drive users to alternate to Visio and Excel
Modelling Working Group Activity	• Fortnightly working group sessions • Governance group update March 2022 • Ideation workshops completed on checking and peer review processes • Ongoing collaboration with projects with potential modelling impact	• Dispatch Modelling/MDB Update (MMI Fix) that streamlines the process for applying the models and reduces the opportunity for error • Customer Name Change Notification Process Improvements to ensure that all modelling parties are aware of the changes and avoids data and tooling errors for misalignment • Improvements to Automation of Gatekeeper changes into ETS that reduces the opportunity for error through manually entering data

6 Technical advisory hours and services

Future Security and Resilience (FSR)

The final phase 1 report and phase 2 draft roadmap were delivered to the Authority mid-January 2022. The report outlined ten opportunities and challenges for power system security and resilience and included feedback received from industry following submissions and workshops held at the end of 2021. The roadmap outlined how these opportunities and challenges will be met. The Authority shared the roadmap with their Board in early March 2022 and the programme is now consulting on the roadmap with industry. We delivered information sessions on the roadmap on 13 April 2022.

The attention of this programme is now turning to scoping the first year of work, which relates to updating technical requirements in the Code and other associated documents. Discussions regarding progressing and funding this work are being held with the Authority.

Other TAS work

TAS work relating to Battery Offering Reserves (TAS 100) - Following the completion of internal System Operator testing in December 2021, the project team have been supporting NZX with their internal testing from January through to March 2022. A second Change Request has been approved to extend this TAS to cover this support period (up to April 2022). The project is tracking to the original approved budget. The draft TAS 100 report will be updated and shared for approval internally, before sharing with the Authority in the April 2022.

December 2019 UTS (TAS 101) - The loss and constraint excess resettlement process was complete on 20 January 2022 and the Closure Report for this work was sent to the Authority on 28 January 2022.

The following table provides the technical advisory hours for Q3 2021/22 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 Q3
TAS SOW 97 – RTP engagement session support	In progress	33.0
TAS SOW 99 – Future Security & Resilience	In progress	276.0
TAS SOW 100 – Battery ESS Offering Reserve	In progress	82.0
TAS SOW 101 – Actions to Correct the Dec Undesirable Trading Situation	Closed	7.0
Total hours		**398.0**

7 Outage planning and coordination

Outage Planning – near real time

We have seen high outage numbers throughout February and March with some weeks reaching around 200 transmission outages plus additional generation outages. A small number of short notice cancellations or delays to outages continued in March, as work crews were impacted by COVID-19.

We have also seen some outage changes as a result of the low hydro situation in Southland.

New Zealand Generation Balance (NZGB) analysis

April's NZGB report forecasts two N-1-G generation balance shortfalls forecast for the base scenario on 3 May and 8 August 2022. Between early May and late August there are a further 18 dates where the N-1-G balance is less than 100 MW and eight of these dates have balances below 50 MW. These periods use the record 29 June and 9 August 2021 demands in their calculations. Since the last NZGB report, there are two issues that have been shared which may impact generators' ability to generate to their nominal capacity.

- The System Operator has previously advised participants of the hydrology challenges in Southland affecting Lake Manapōuri and Te Anau and these challenges may further reduce available generation closer to real-time.
- A Planned Outage Coordination Process (POCP) Notification impacting the Taranaki Combined Cycle station has been entered into POCP. This notification does not include a reduction in MW output but describes operating limitations which may affect this generator's ability to operate at its nominated capacity as modelled in NZGB.

8 Power systems investigations and reporting

Nothing to report this quarter.

9 Performance metrics and monitoring

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

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

		Annual Target	Actual to date	Points
Smart about money				
Perception of added value by participants		80%	N/A	
Customers are informed and satisfied				
Annual participant survey result		83%	N/A	5
Annual participant survey result response rate - First tier stakeholders		80%	N/A	
On-time special event preliminary reports		90% ≤ 10 business days	0 required	5
Future thinking and insights	Future thinking report	≥ 1	0	5
	Longer Market Insight reports	≥ 4	3	5
	Bite-sized Market Insights	≥ 45	36	
Quality of written reports		100% of standard	100%	
Role impartiality		80%	N/A	5
Responding to requests for information from the Authority		100% by agreed deadline	0 requested	
Code compliance maintained and SOSPA obligations met				
Market breaches remain below threshold		≤ 3 @ ≥ $40k	1	10
Breaches creating a security risk - below threshold/within acceptable range		≤2	0	10
On-time SOSPA deliverables		100% (50)	100% (24)	10
Successful project delivery				
Project delivery	Service Maintenance projects	≥ 70% on time	33%	
		≥ 70% on budget	100%	
	Market Design and Service Enhancement projects	≥ 70% on time	0 completed	
		≥ 70% on budget	0 completed	
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	100%	
Fit-for-purpose tools				
Capability functional fit assessment score		76.00%	N/A	
Technical quality assessment score		70.00%	N/A	
Sustained SCADA availability		99.90%	99.99%	10
Maintained timeliness of schedule publication		99.00%	99.99%	10

9.1 Dispatch accuracy dashboard

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

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

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

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

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

Below are instances of variations we have observed this quarter

Energy

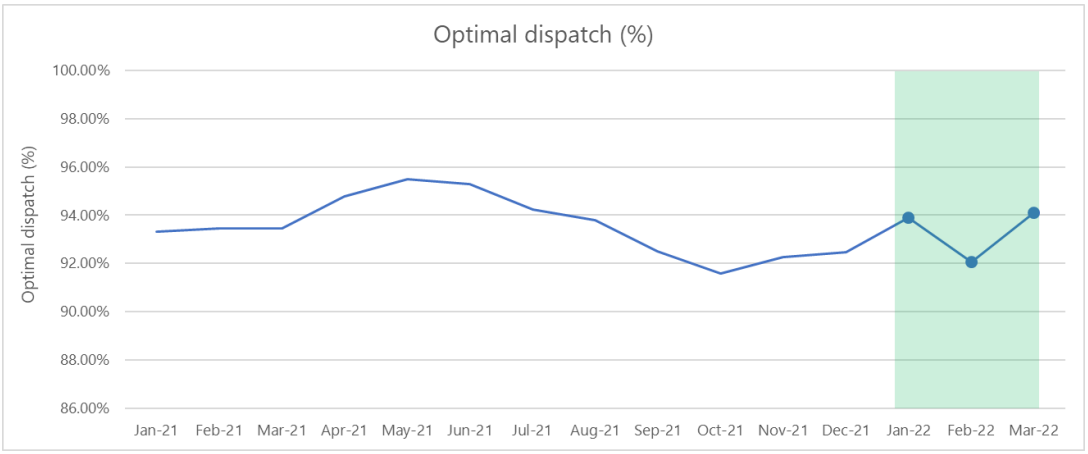
Overall industry performance this quarter – January to March 2022

Overall, the results for January to March 2022 (Q3) this year are in line with what we observed last year. This reflects the seasonal trend of calmer summers and hence less modulation from the HVDC outside of the 30 MW band.

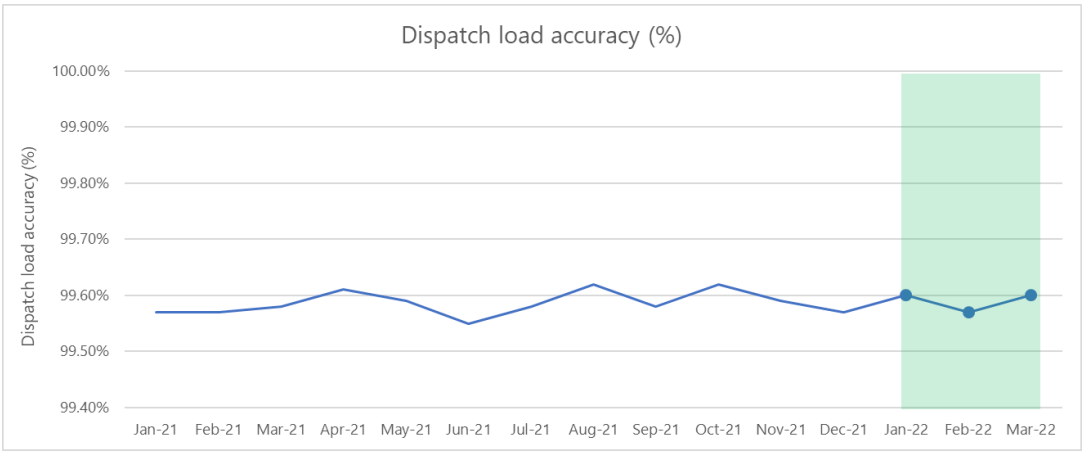
- *Frequency excursions (February)*
    - All excursions in the month were as a result of Tiwai potline trips
- *HVDC modulation (general)*
    - Something to note is that the % of minutes where maximum modulation exceeds 30 MW is showing a rising trend, which we expect will continue when the new windfarms are added to the system. We are keeping a close eye on this measure and will be revisiting the 30 MW band if this trend continues.

Optimal dispatch this quarter

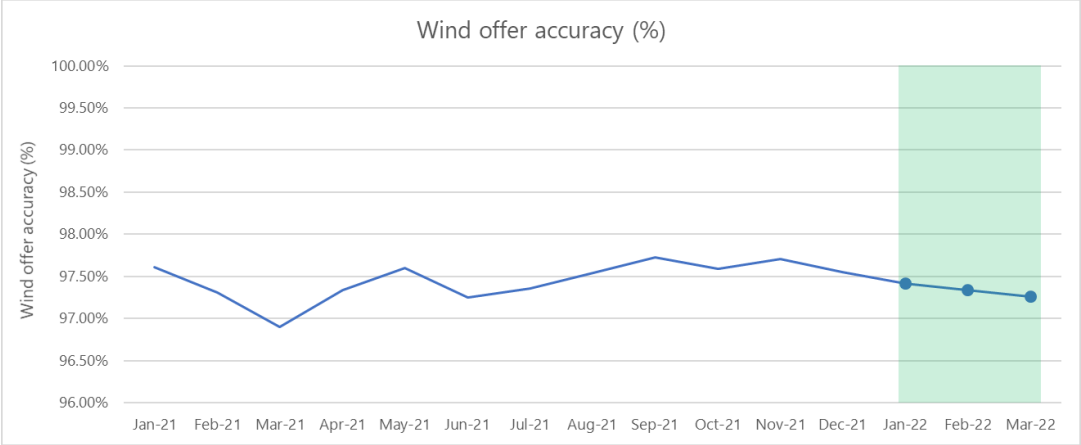
The optimal dispatch measures are also similar to those in Q3 last year. The chart below shows the monthly measure with the month-on-month variation from Jan-21.



The dispatch load accuracy measure is also similar to Q3 last year. This measure has been fairly consistent over the last 12 months. We will continue to monitor this measure as more embedded generation enters the system that can impact the load observable to the market.



The wind offer accuracy measure is lower than Q3 last year. The current quarter shows a declining trend in the wind offer accuracy metric, similar to Q1 last year. As mentioned previously, the addition of more wind generation to the system is something that will increasingly impact this and the optimal dispatch measure. We will be watching the wind offer accuracy measure as more wind is added to the system.



Reserves

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

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

<u>Observations this quarter – January to March 2022</u>

As with the energy measures, there are no unexpected variance for Q3.

- *Proportion of time DCCE[1] is risk setter (February)*
  - This variation corresponds to the periods of single pole outages in the month.

10 Cost of services reporting

The cost of services reporting for 2020/21 was delivered to the Authority on 22 December 2021.

11 Actions taken

The following table contains a full list of actions taken during Q3 2021/22 regarding the System Operator business plan, statutory objective work plan, participant survey responses and any remedial plan, as required by SOSPA 12.3 (b).

Item of interest	Actions taken
(i) To give effect to the **System Operator business plan**:	• Reviewed System Operator Rolling Outage Plan and run a rolling outage exercise *We ran a rolling outage exercise on 24 February.* • Delivered phase 2 of Real Time Pricing

[1] This is an event due to the loss of one HVDC pole for which, in the reasonable opinion of the System Operator, resources are able to be economically provided to maintain the security of the grid system and power quality without disconnecting demand.

Item of interest	Actions taken
	This was delivered on 24 March. • Continued to increase use of the webinar briefings *We rolled out the first of our fortnightly industry forums in webinar format in March.* • Prepare and implement an action plan to improve our security of supply processes, based on insights from the 2021 dry year experiences • Support the Authority in reviewing the policy settings for management of dry-year risk *We are consulting on six proposed changes intended to reduce uncertainty and subjectivity in assessing and managing dry-year risk*
(ii) To comply with the **statutory objective work plan**:	• Evaluate and revise performance metrics, targets and incentive payment calculation *During quarter 3, we have:* • *Established the core project team within the System Operator* • *Upskilled the team to be able to carry out the methodology in-house* • *Confirmed the pilot scope to focus on two areas:* ○ *Management of System Events* ○ *Project Delivery* • *Worked with the System Operator Senior Leadership Team to create proposed Critical Success Factors and external outcomes (KRIs)* • *Worked with a diverse and cross-functional set of Operations staff to derive a long-list of performance measures for each of the critical success factors*.
(iii) In response to participant responses to any **participant survey**:	**Feedback from the 2020-21 survey** • What topics would you like to see covered in communications? - "Discussions on every aspect as we are seeking to understand the System Operator and the services provided" *This is the aim of our new fortnightly industry forums*
(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

Despite a single large inflow event in early February, conditions have been generally dry over the last quarter. This is as predicted by NIWA and in line with current La Niña conditions. As of 10 April 2022, national hydro storage sits at 82% of average for the time of year largely propped up by lakes Tekapo and Pukaki which combined are approximately 85% full and together make up 70% of national hydro storage capacity.

A large February inflow event largely missed lakes Manapōuri and Te Anau. As a result, they now sit in their low operating ranges which limits output from Manapōuri. This has been causing some voltage issues overnight which have been being managed by the National Coordination Centre (NCC). An Urgent Grid reconfiguration was requested by the System Operator, this was accepted and implemented on the 10 April 2022. This removed the risk of load management under specific circumstances should Manapōuri be able to generate.

NIWA's climate outlook for April to June suggests a continuation of La Niña conditions (65% chance), however also notes that rainfall may be influenced by incidences of ex-tropical cyclones and atmospheric rivers which may see heavy rainfall events.

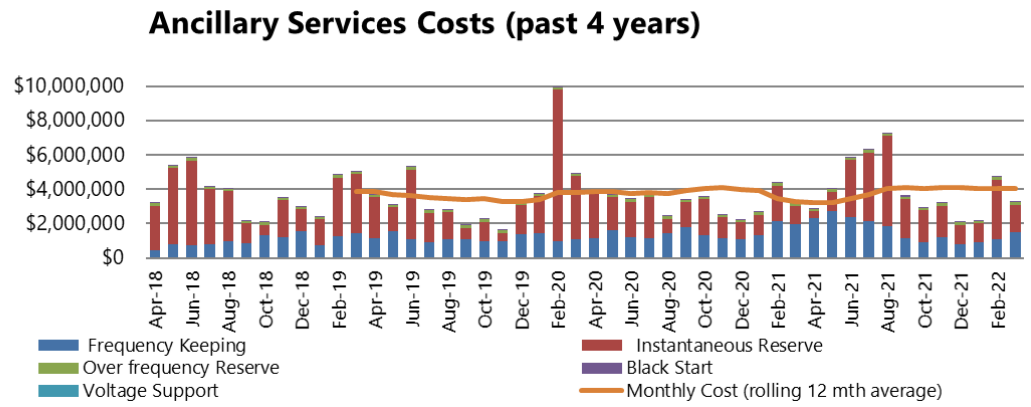
A planned outage of the Maui gas production facility has been pushed out from April to May 2022 and will end on 10 June 2022. Following this it is expected that a material increase in gas production from Maui will begin to materialise.

On 4 April, Contact Energy advised that Taranaki Combined Cycle (TCC) will operate with a 2,000 hour limitation, limiting the number of GWh the unit will produce over the winter ahead. Despite this, the unit can run in open cycle mode without limitation. The System Operator markets team will be updating the Electricity Risk Curves to reflect this.

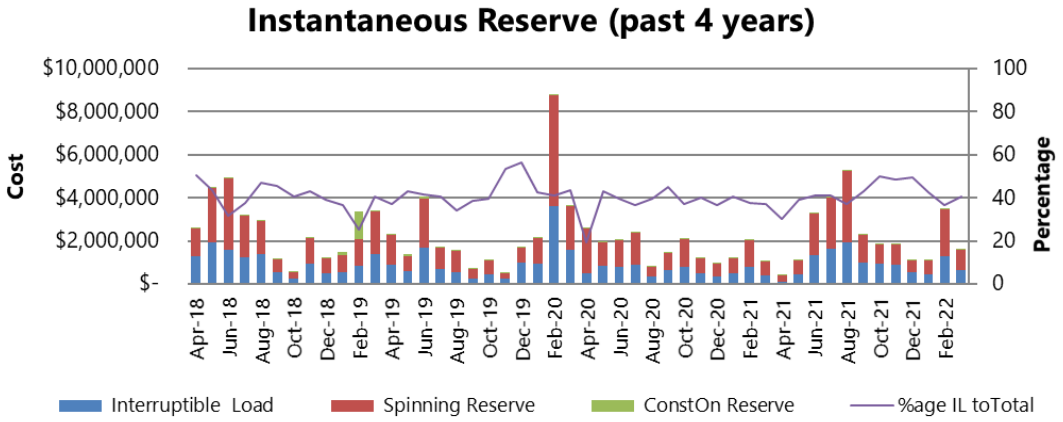
Southland low hydro issues

The Southland region is currently experiencing a prolonged dry period, which is resulting in declining lake levels and low hydro generation. This has particularly impacted inflows into lakes Manapōuri and Te Anau and both lakes are in their low operating range. We have been assessing and continue to assess security implications for the region. As we complete assessments we have been communicating with participants. This has included arrangements for an urgent grid reconfiguration and requests to asset owners to reconsider outages.

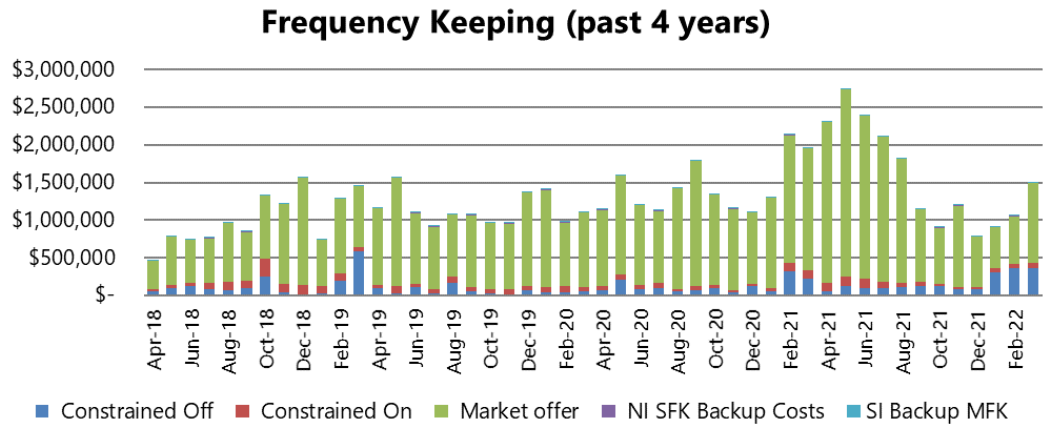
13 Ancillary services



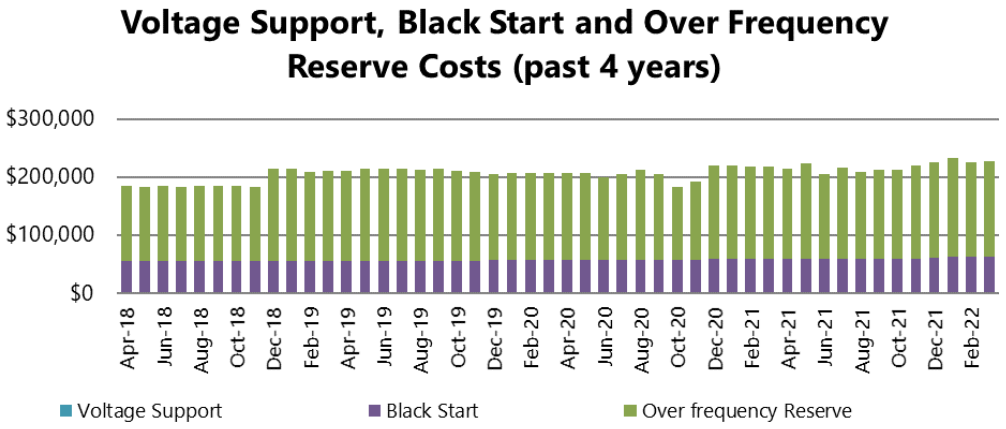
This quarter's ancillary service costs were $10.3 million, which is a 2 % increase compared to the previous quarter's costs of $8.3 million. This reflects significantly higher costs for both instantaneous reserves and frequency keeping since December 2021. The ancillary service costs were especially high in February 2022 totalling $4.8 million.



This quarter, the instantaneous reserve costs were $6.2 million, which is a 29% increase to the previous quarter ($4.8 million). Interruptible load costs were roughly the same as last quarter with an increase of $37k (2% increase), spinning reserves increased by $1.4 million (57% increase), and constrained on costs decreased by $7k (27% decrease). The quantity of reserves procured steadily increased over the quarter while high prices were apparent in both February and March. The significant increase in reserves prices in February are the result of the single and bi-pole outages.



This quarter the frequency keeping costs were $3.5 million, which is a 20% increase compared to the previous quarter's costs of $2.9 million. Frequency keeping costs increased over the quarter in response to the single and bi-pole outages in February and in response to the prevailing conditions in March.

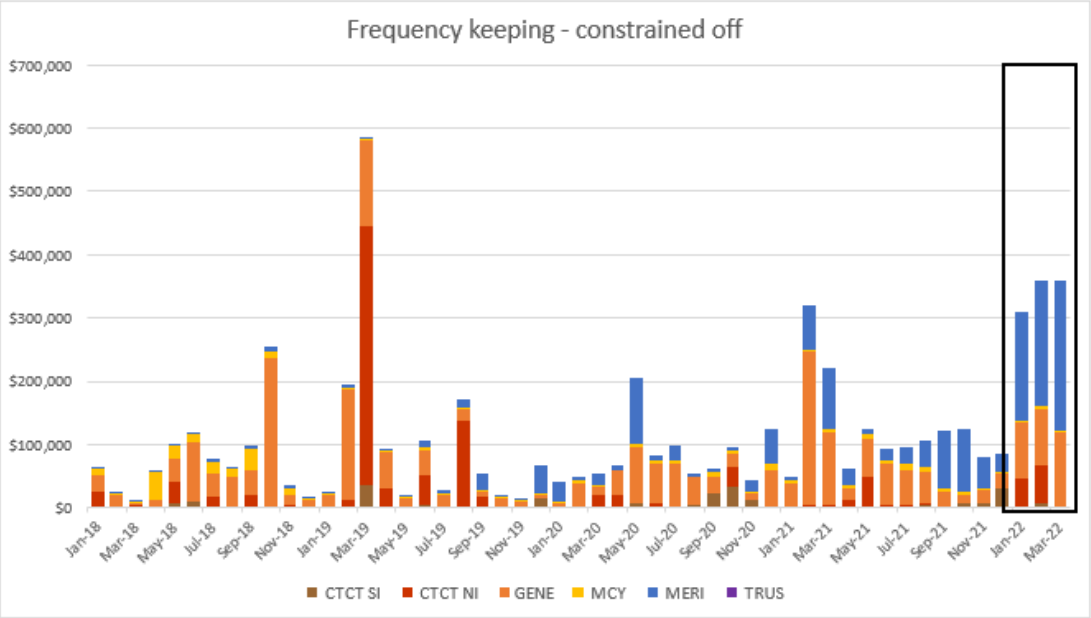


This quarter the costs for both over frequency and black start have increased slightly to reflect changes in the new ancillary services contracts and annual Consumer Price Index adjustments. There are no voltage support costs as there is no need to procure this ancillary service at this time.

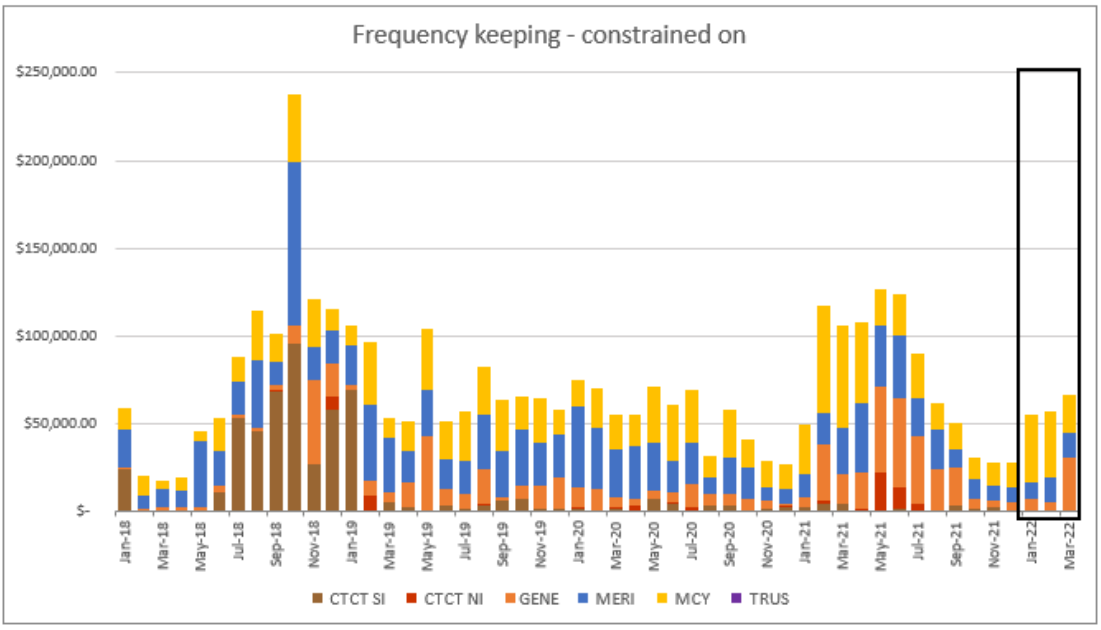
13.1 Constrained on/off costs

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

Frequency Keeping

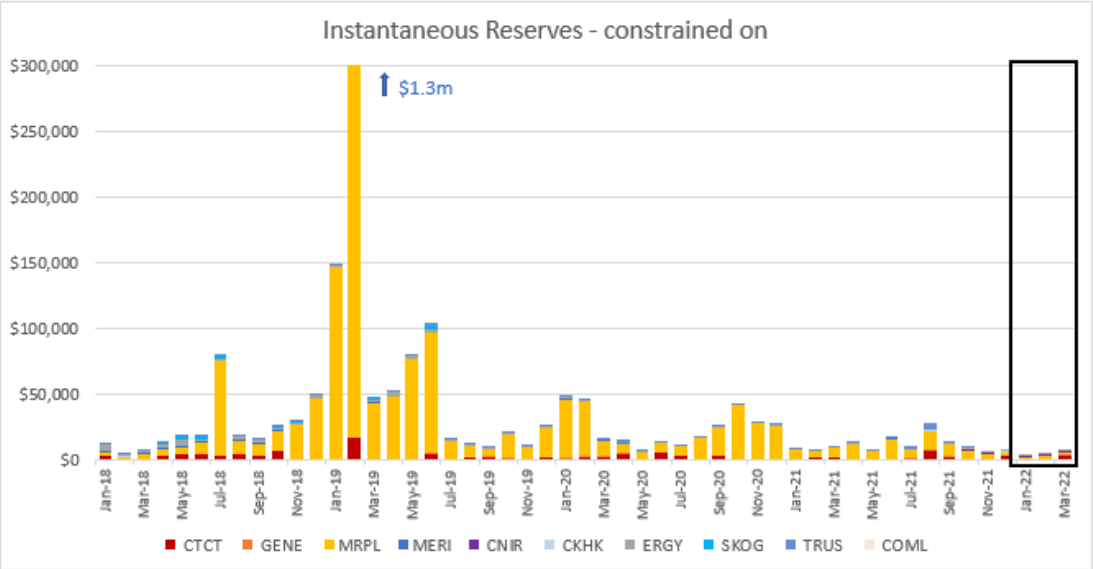


For Q3 2021/22, the frequency keeping constrained off costs increased significantly by 256% on the previous quarter to $1.0 million. The North Island constrained off costs increased significantly by 529% over this period and the South Island's increased by 176%. The high constrained off costs are the result of frequency keeping being provided by stations that would otherwise be offering in the energy market which has had high prices this quarter.



For Q3 2021/22, the frequency keeping constrained on costs increased by 95% on the previous quarter to $180k. The North and South Island frequency keeping constrained on costs both increased (by 143% and 11% respectively) since the previous quarter.

Instantaneous Reserves



For Q3 2021/22, the instantaneous reserves constrained on costs were 27% lower than the previous quarter reaching as low as 4.2k in January 2022.

14 Commissioning and Testing

Mercury's 119MW Turitea North windfarm is fully commissioned. The South windfarm is on track for commissioning later this year and will add approximately another 100 MW of capability.

We are treating two 10-30 MW solar farms as 'committed' projects despite not meeting all pre-requisites for System Operator involvement. Both are planning on connecting behind Top Energy's distribution network and will be treated in the same way as WEL's 35 MW battery connecting near Huntly. Both have an intention to connect in the next 12 – 18 months. By taking this approach we are managing the risk of System Operator activities becoming the critical path during commissioning.

We will be seeking an opinion from the Authority on an interpretation of Point Of Connection, as this is becoming a point of contention with some generation connecting within distribution networks. The outcome of the interpretation from the Authority has implications for Asset Owner Performance Obligations.

15 Operational and system events

January - March

Voltage – Lower South Island - With low hydro generation in the Southland region during January, Clutha Upper Waitaki Lines Project (CUWLP) outages, and other concurrent outages in the region, it was challenging to manage voltage stability limits

in the event of a contingency occurring overnight. This was managed in real-time with generators leaving units on tail-water depressed and through publishing a temporary regional constraint.

Cyclone Dovi - Over the weekend of 12-13 February 2022 there where high levels of distribution feeder outages as a result of cyclone Dovi. The control room teams reacted quickly putting processes in place to effectively manage and triage workload.

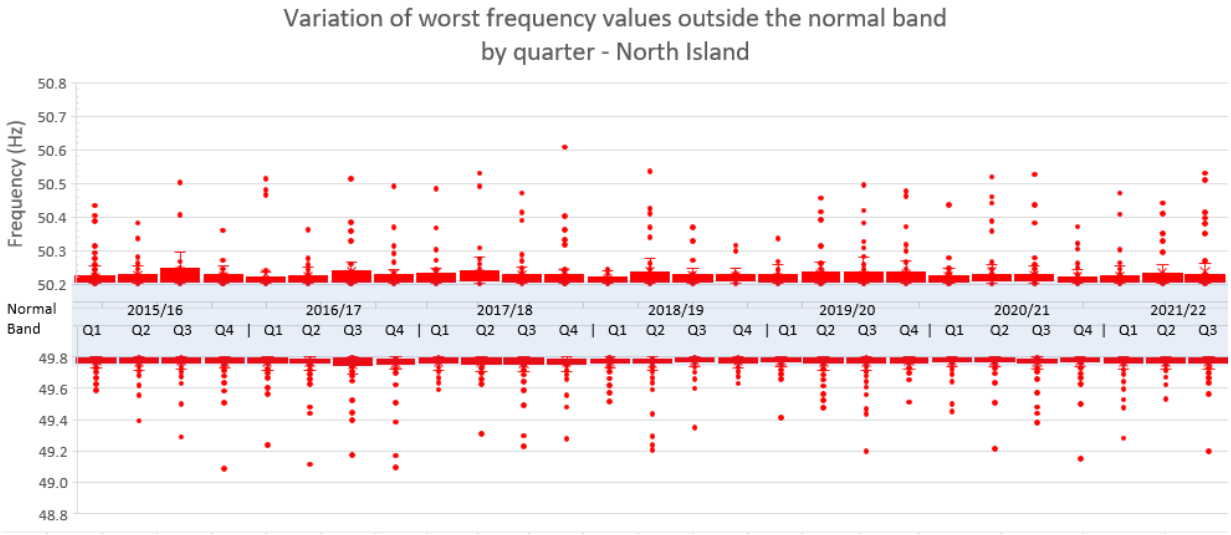
HVDC Outage Extension - The HVDC bipole outage planned for 19-20 February 2022 was extended by the Grid Owner. Transpower held industry conference calls at 8pm on 20 February and 11am on 21 February to communicate the situation to market participants.

16 Frequency fluctuations

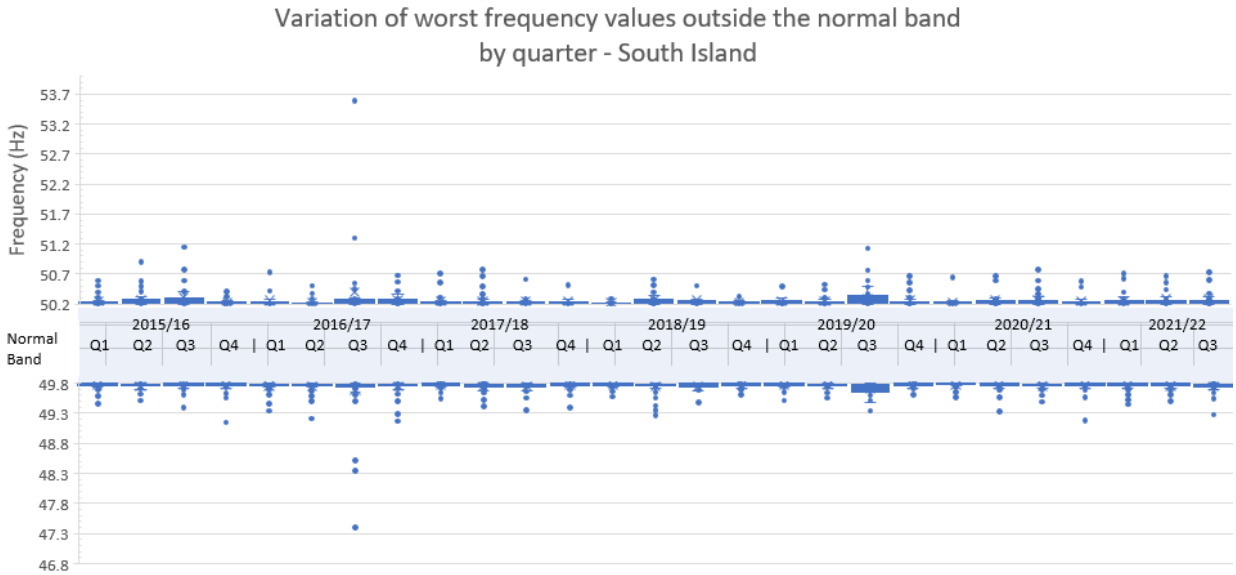
16.1 Maintain frequency in normal band (Frequency value)

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

North Island



South Island

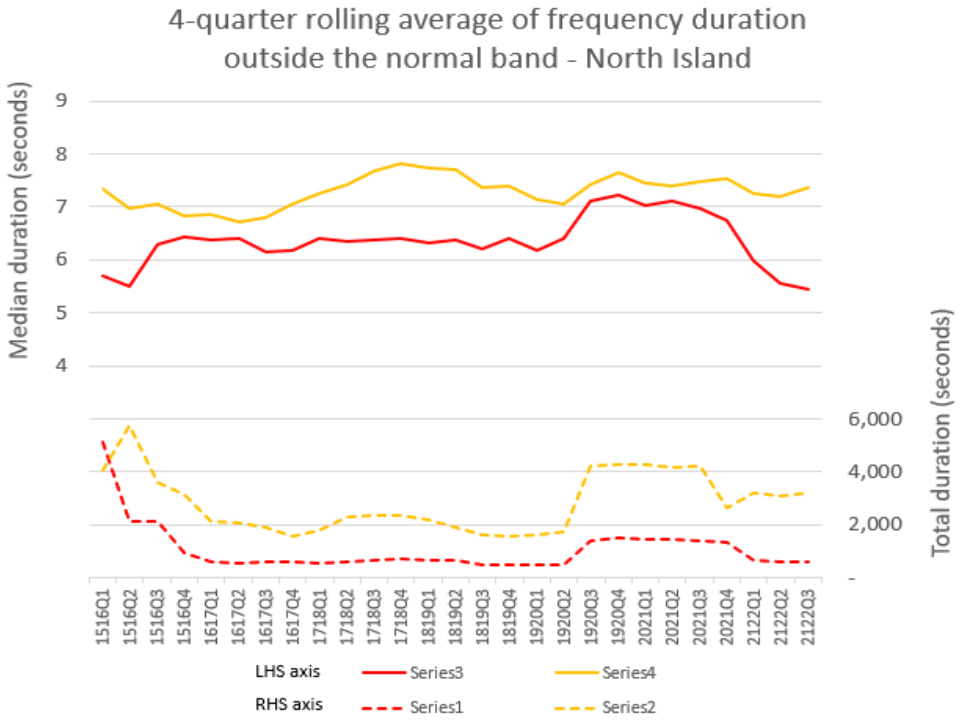


Note: These box and whisker charts show the distribution of data. The “box” represents the distribution of the middle 50% of the data, the “whiskers” indicate variability, and outliers are shown as single data points.

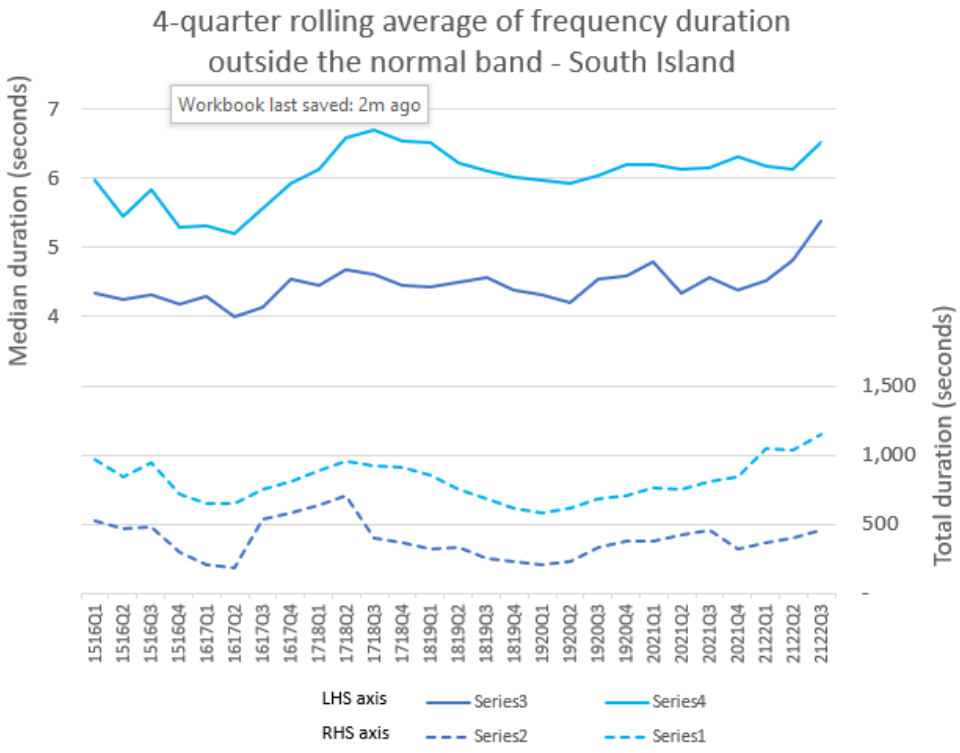
16.2 Recover quickly from a fluctuation (Time)

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

North Island



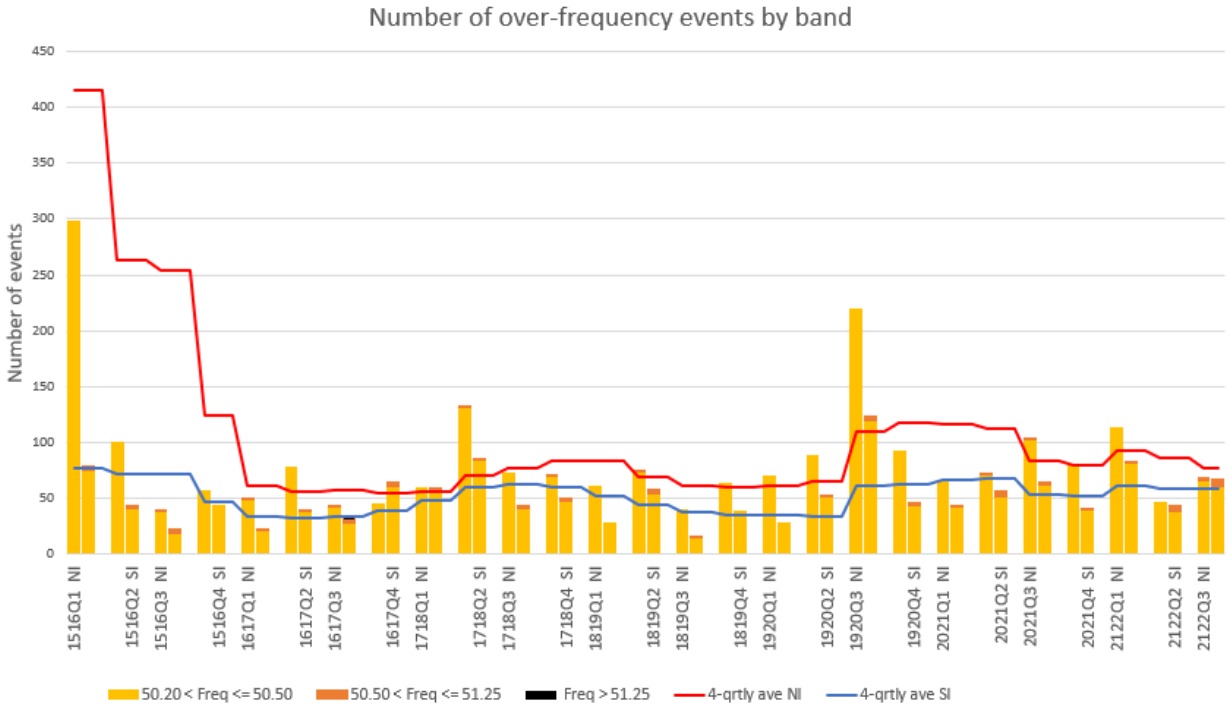
South Island



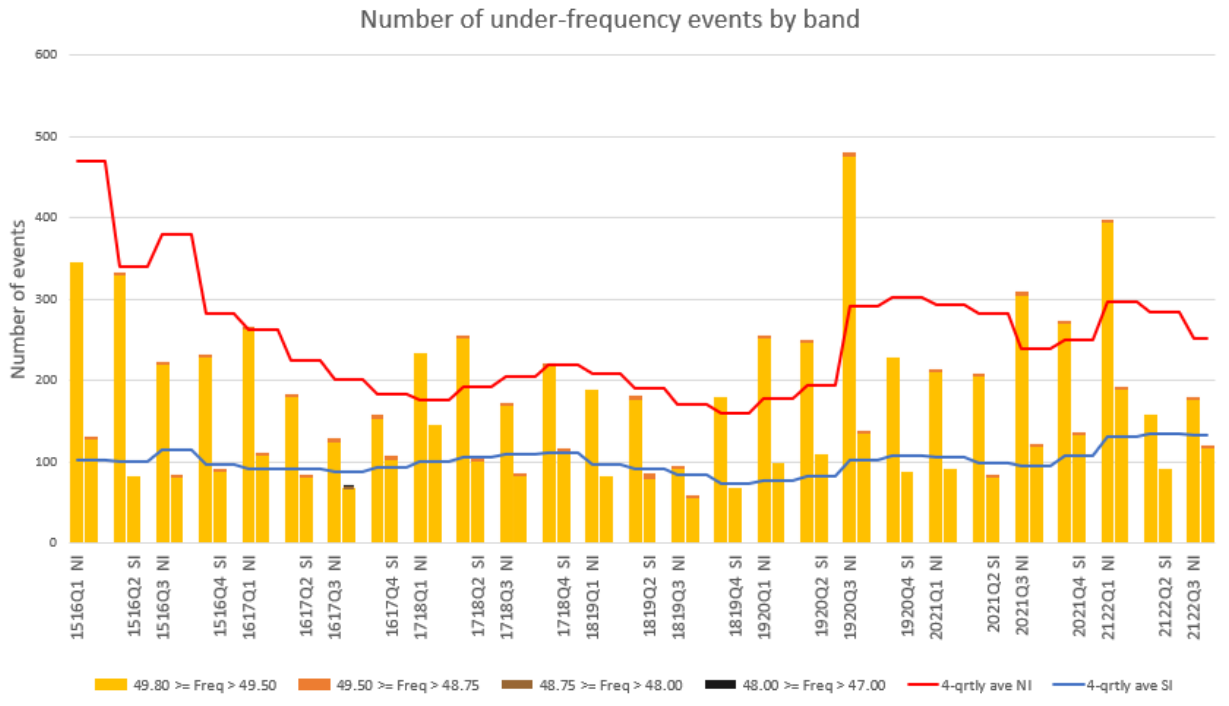
16.3 Manage frequency and limit rate of occurrences during momentary fluctuations (Number)

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

Over-frequency events



Under-frequency events



16.4 Manage time error and eliminate time error once per day

There were no time error violations in the reporting period.

17 Voltage management

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

18 Security notices

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

Notices issued	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22
Demand Allocation Notice	-	-	-	-	1	-	--	--	-	-	-	-
Grid Emergency Notice	-	-	1	-	4	2	--	2	-	-	-	-
Warning Notice	-	-	-	1	4	-	--	--	-	-	-	-
Customer Advice Notice	8	14	14	11	42	34	9	7	5	7	9	15

19 Grid emergencies

There were no grid emergencies declared by Transpower as System Operator from January to March 2022.

Appendices

Appendix A: Discretion

January

Event Date & Time	Event Description
10/01/2022 13:01:21	COL0661 COL0 Discretion Clause 13.70, Part 13 ENR Max : 29 West Coast split due to KIK T2 tripping. Last Dispatched Mw: 29
10/01/2022 12:46:35	COL0661 COL0 Discretion Clause 13.70, Part 13 ENR Max : 29 West Coast split due to KIK T2 tripping.t Dispatched Mw: 39

February

Event Date & Time	Event Description
3/02/2022 14:59	HLY2201 HLY5 Discretion Clause 13.70, Part 13 ENR Min : 200 Unit 5 dispatched to 173.5MW, trader called to claim rule 13.82a exemption, resource consent breach. Had been discussed with SC who agreed Unit 5 required for security (UNI voltage management), 200 MW min discretion applied. Last Dispatched Mw: 173.45. Discretion ended at 05:27.
5/02/2022 10:03	HLY2201 HLY5 Discretion Clause 13.70, Part 13 EN Min : 190 Genesis Trader claimed Rule 13.82 (a) due to resource consent breach. As per Rule 13.57, discretion applied to meet least cost dispatch. HLY U5 importing 100MVArs and required for voltage management as well. Last Dispatched Mw: 168.39
8/02/2022 4:37	COL0661 COL0 Discretion Clause 13.70, Part 13 ENR Max : 25 Bus fault KUM. West Coast split: Last Dispatched Mw: 39
8/02/2022 4:47	COL0661 COL0 Discretion Clause 13.70, Part 13 ENR Max : 27 Bus fault KUM, West Coast split. Last Dispatched Mw: 25.27
8/02/2022 5:58	KUM0661 KUM0 Discretion Clause 13.70, Part 13 ENR Max : 0 KUM Bus fault, West Coast split.: Last Dispatched Mw: 0
12/02/2022 21:04	KPA1101 KPI1 Discretion Clause 13.70, Part 13 ENR Max : 0 OPK_KPI_SFD_2, KPI 92 & 32 tripped at 10:00 Last Dispatched Mw: 14
23/02/2022 1:30	LTN2201 TUR0 Discretion Clause 13.70, Part 13 ENR Max : 90 To clear RTCA violation of LTN-T3 for a tripping of BPE-LTN-1. HAY-WIL-LTN-2 is on outage. Last Dispatched Mw: 91.8
23/02/2022 3:09	LTN2201 TUR0 Discretion Clause 13.70, Part 13 ENR Max : 95 To clear RTCA violation of LTN-T3 for a tripping of BPE-LTN-1. HAY-WIL-LTN-2 is on outage. Last Dispatched Mw: 90
26/02/2022 13:49	HLY2201 HLY5 Discretion Clause 13.70, Part 13 ENR Min : 215 Last Dispatched Mw: 167.85 Dispatched below running min. Trader claimed rule exemption. kept on for security.

March

Event Date & Time	Event Description
1/03/2022 1:58	HLY2201 HLY2 Discretion Clause 13.70, Part 13 ENR Max : 0 Last Dispatched Mw: 230
1/03/2022 3:03	WHI2201 WHI0 Discretion Clause 13.70, Part 13 ENR Min : 40 Required for low residual post HLY U4 trip. Extended during SPL controlled shutdown until 19:00 01/03/22: Last Dispatched Mw: 52
1/03/2022 5:26	SFD2201 SPL0 Discretion Clause 13.70, Part 13 ENR Max : 0 Controlled Shutdown from 145MW. EC applied discretion as frequency was dropping and no Bonafide had been received from Contact Control Centre. Last Dispatched Mw: 145
20/03/2022 12:36	CYD2201 CYD0 Discretion Clause 13.70, Part 13 ENR Max : 0 Contact claimed rule 13.82A for CYD minimum of 70MW. Other generation in area available CYD dispatched to 0MW. Last Dispatched Mw: 26.3
24/03/2022 17:05	BWK1101 WPI0 Discretion Clause 13.70, Part 13 ENR Max : 0 Circuit tripped in the area not dispatched claimed Bonafide. Last Dispatched Mw: 23

Appendix B: Dispatch Accuracy Dashboards

Energy

Same quarter in 2020/21

This quarter 2021/22

			2021 January	February	March	April	May	June	July	August	September	October	November	December	2022 January	February	March
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	481	557	360	350	347	652	895	472	509	584	648	449	355	422	445
	Instances where the system operator has applied discretion under 13.70 of the Code to meet dispatch objective		-	3	3	-	1	15	9	12	32	11	16	24	2	9	5
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 for additional dispatches	NI	6.88	6.64	6.88	6.73	7.14	6.89	7.08	7.11	6.98	7.00	6.96	7.52	7.32	6.41	7.11
		SI	6.35	6.48	6.45	6.59	6.65	6.58	6.64	6.53	6.71	6.60	6.83	6.68	6.76	6.32	6.69
Time error (s)	Average absolute daily time error (s) indicates imbalance between generation and load, a reflection of imperfect dispatch	NI	0.1953	0.2447	0.2019	0.2003	0.2113	0.2148	0.2379	0.2408	0.2317	0.1941	0.1862	0.2110	0.2087	0.2261	0.1901
		SI	0.2266	0.2506	0.2051	0.1898	0.2213	0.2072	0.2490	0.2332	0.2087	0.1879	0.2041	0.2095	0.1707	0.2258	0.1799
Frequency excursions	Number of frequency excursions (>0.5Hz from 50Hz)		5	3	2	-	2	3	3	1	2	-	5	1	2	6	2
FK within 1% of band limit	% of time frequency keepers spend near to or exceeding their regulation limits indicates the need to redispatch.	NI	2.39%	2.88%	2.15%	2.94%	3.59%	2.76%	3.28%	3.01%	2.66%	2.54%	2.64%	3.47%	2.68%	3.54%	2.58%
		SI	3.43%	3.78%	3.13%	3.87%	5.75%	2.78%	3.31%	2.92%	2.66%	2.55%	2.59%	3.48%	2.72%	3.55%	2.31%
FK outside of	% of time frequency keepers spend outside their regulation limits	NI	0.01%	0.05%	0.02%	0.02%	0.09%	0.01%	0.01%	0.02%	0.04%	0.02%	0.02%	0.01%	0.01%	0.08%	0.05%
		SI	0.00%	0.03%	0.00%	0.00%	0.14%	0.00%	0.00%	0.02%	0.01%	0.00%	0.02%	0.00%	0.00%	0.03%	0.01%
HVDC modulation beyond 30MW band	% of minutes where the maximum HVDC modulation exceeds 30MW away from its dispatch setpoint. This indicates greater variability in the system, but can also indicate the need for redispatch.		9.00%	10.29%	11.97%	10.19%	10.60%	13.79%	15.05%	11.78%	10.93%	8.11%	10.05%	9.09%	9.09%	10.37%	7.38%
Constrained on energy- Total	Total Monthly Generation	MWh	3,349,472	3,155,453	3,338,962	3,364,562	3,722,811	3,726,894	4,038,786	3,857,499	3,628,916	3,553,128	3,411,254	3,381,156	3,423,033	3,102,676	3,300,548
	Total constrained on - All sources	MWh	24,386	13,538	10,561	24,629	23,878	23,017	25,760	25,586	33,595	26,561	24,861	37,425	27,518	25,195	25,071
		% of all generation	0.73%	0.43%	0.32%	0.73%	0.64%	0.62%	0.64%	0.66%	0.93%	0.75%	0.73%	1.11%	0.80%	0.81%	0.76%
Constrained on energy ($) - Frequency keeping	Total constrained on $ due to frequency keeping (within band is attributable to SO)	$ Constrained On Energy	325,530	426,305	407,568	574,408	849,250	529,563	678,100	418,027	387,985	232,948	269,822	428,273	264,827	351,930	1,048,490
		$ Grid Constrained On Energy	49,807	43,198	35,972	108,176	126,538	123,621	90,143	61,541	50,707	31,140	28,176	28,196	41,297	57,475	66,726
Optimal Dispatch (%)	Compares the average impact of a perfect foresight case against dispatch solutions. Indicates impact of wind offer, load forecast and PSD accuracy.	%	93.310%	93.450%	93.440%	94.790%	95.500%	95.310%	94.240%	93.790%	92.500%	91.500%	92.270%	92.480%	93.910%	92.050%	94.100%
Dispatch load accuracy error (%)	Average absolute difference between forecast generation (load plus losses, including PSD) and actual generation relative to the average actual generation	%	99.570%	99.570%	99.580%	99.610%	99.590%	99.550%	99.580%	99.620%	99.580%	99.620%	99.590%	99.570%	99.600%	99.570%	99.600%
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	%	97.610%	97.310%	96.900%	97.340%	97.600%	97.250%	97.360%	97.540%	97.730%	97.340%	97.710%	97.550%	97.410%	97.340%	97.260%

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 energy dashboard

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

Measures selected

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

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

Colour scale

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

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

[2]

Metric[3]

The measures that contribute towards the metric are:

- FK outside of band limit [4]
- 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: [5]

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

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

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

Example:

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

Metric calculation rows		FK outside band	2
		Constrained on	3
		Optimal Dispatch	3
Dispatch accuracy %	Metric out of 3 (3 is best possible result)		2.7

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

[2] 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
[3] This metric is for analysis purposes and is not part of the performance metrics report to the Authority
[4] 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
[5] The score was changed during the year from a five point (1-5) to a three point (1-3) scale.

Reserves

Same quarter in 2020/21

This quarter 2021/22

			2021											2022			
			January	February	March	April	May	June	July	August	September	October	November	December	January	February	March
FIR procured vs Risk	NI+SI Fast Instantanous Reserve (FIR) procured divided by the estimate of FIR risk. A greater proportion suggests over procurement of reserves in the relevant island. Monthly average per trading period.	ACCE	0.78	0.82	0.78	0.70	0.73	0.78	0.70	0.71	0.66	0.68	0.72	0.64	0.74	0.82	0.76
		DCCE	1.04	1.13	0.77	NIL	0.88	NIL	0.88	0.87	0.84	0.79	0.74	0.78	NIL	0.88	NIL
FIR procured (MW)	Average FIR MW procured per trading period		239	255	224	180	222	286	251	257	203	198	204	166	217	268	244
SIR procured (MW)	Average SIR MW procured per trading period		320	339	300	266	314	381	372	386	313	303	301	263	307	357	337
FIR procured ($)	Total monthly cost ($) of FIR procured		946,569	1,649,525	923,443	284,960	800,816	2,029,096	1,803,527	3,083,309	1,224,614	867,796	850,026	604,671	648,275	2,668,511	1,005,452
SIR procured ($)	Total monthly cost ($) of SIR procured		222,854	399,630	138,594	102,967	278,623	1,264,344	2,216,743	2,198,285	1,038,035	973,776	953,870	498,131	425,975	819,490	555,056
Net free reserves (NFRs)	Average national Net free reserves (NFRs) for a trading period where the risk type is binding, averaged over a month	AC	87	88	86	92	100	101	124	116	115	107	106	103	97	88	96
		DC	60	62	79	NIL	102.76	NIL	77	95	88	96	112	99	NIL	82	NIL
Reserve sharing	Average percentage of FIR procured that is shared between islands. FIR shared NI+SI / FIR MW Procured NI+SI (Average per trading period).		44%	41%	52%	61%	45%	35%	36%	26%	37%	35%	52%	42%	51%	33%	42%
IL vs Spinning Reserve	Percentage of IR procured as interuptable load.	FIR	35%	34%	29%	29%	28%	40%	39%	33%	34%	36%	32%	32%	34%	35%	34%
		SIR	34%	37%	28%	30%	28%	41%	38%	36%	37%	38%	35%	35%	39%	36%	34%
Risk setter	Most common risk setter (highest number of trading periods)	NI	HLY5CE	HLY5CE	HLY5CE	HLY1CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE
		SI	ManualCE;OtherIslandCE	OtherIslandCE	OtherIslandCE	ManualCE;OtherIslandCE	OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	OtherIslandCE	ManualCE;OtherIslandCE
Proportion of time risk setter	Proportion of time each type of risk was FIR risk setter	ACCE	99.80%	98.29%	99.66%	99.93%	99.93%	100.00%	99.80%	78.18%	95.13%	87.77%	95.56%	94.83%	99.93%	89.43%	100.00%
		DCCE	0.20%	1.64%	0.34%	0.00%	0.07%	0.00%	0.20%	22.09%	2.50%	10.35%	2.78%	1.08%	0.00%	10.57%	0.00%
		DCECE	0.00%	0.07%	0.00%	0.07%	0.00%	0.00%	0.00%	0.14%	2.36%	1.88%	1.67%	4.10%	0.07%	0.07%	0.00%
Average MW risk when risk setter	Average risk MW for each risk type when they are the FIR risk setter	ACCE	306	308	287	258	305	366	356	329	305	283	287	247	294	313	319
		DCCE	288	346	477	0	364	0	393	394	367	319	323	281	0	420	0
		DCECE	0	129	0	105	0	0	0	159	50	106	62	240	149	0	0

Understanding the reserves dashboard

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

Measures selected

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

> Monthly average of [FIR MW procured as a percentage of the FIR risk] per trading period (%)
> across the whole of New Zealand[6] for AC contingent events (ACCE)

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

Colour scale

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

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

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

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

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