TRANSPOWER

Quarterly System Operator and system performance report

For the Electricity Authority

July to September 2021

Report Purpose

This report is Transpower's review of its performance as System Operator for Q1 2021/22 (July to September 2021), 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 (July to September 2021)

SOSPA deliverables

- The System Operator Annual Self-Review for the 2020/21 financial year was delivered to the Authority. As part of this we reported a score of 100% against the weighted performance metrics that contribute towards our incentive payment. The Authority is now carrying out a review of System Operator performance for 2020/21 which will be published later this year.
- The annual publication of the Joint Development Programme was prepared and published on the Authority's website in August.
- The 2021/22 SOSPA audit programme is underway with the Under-Frequency Event (UFE) audit fieldwork in progress and being performed by an independent consultant.

Security of Supply and market information

- At the end of September, New Zealand hydro storage was 136% of average for the time of year, following three months of heavy rainfall; this is above the 90th percentile of historic averages.
- Cold weather across the country lead to a new national peak demand record on Monday 9 August when demand reached 7,080 MW (half-hourly average).
- Improved hydro storage levels coupled with periods of strong wind and the onset of the COVID-19 national alert level 4 lockdown in August, all contributed to a drop in the average price.
- On 17 September, the New Zealand power system was operating on 96% renewable energy for nearly four hours as no thermal generation was on the system (there was still co-generation).

Projects and TAS work

- RTP phases two and three are progressing well. Inter-project scheduling and environment conflicts continue to be monitored with no significant issues arising.
- TAS work relating to Battery Offering Reserves (TAS100) has been approved and the December 2019 UTS (TAS101) is in the final stages of the approval process.

Risk and Preparedness

- Ahead of the severe storm warning for the weekend of 17 July, both control rooms worked proactively to prepare in the event of potential weather-related service interruptions. We responded to multiple alarms triggered by weather-related events in distribution networks, particularly in the Rotorua/Bay of Plenty region, and the West Coast of the South Island.
- With the change to COVID-19 national alert level 4 across New Zealand on 17 August, the Operations division activated its incident management response

team, notified the Authority and commenced regular situational reporting. In addition, a number of health and safety measures are being implemented to ensure the safety of staff and the security of the system. These measures include a recommended approach for the extended-term management of COVID-19 once New Zealand reaches a plateau level of vaccination and lockdown controls are released. This piece of work will take a near-term view for what can be done in the short-term as well as some longer-term recommendations that may require investment.

Generation commissioning

- Turitea Wind Farm started commissioning its first turbines at the end of July. It is expected commissioning of the full station (118 MW) will run through until November 2021.

Incidents

- On 9 August, the System Operator forecast and communicated a residual shortfall over the evening peak. As the country approached the evening peak a generation shortfall coupled with high demand resulted in a Grid Emergency being declared. An instruction to reduce demand was issued resulting in some consumers being disconnected. An independent investigator has been engaged by Transpower to review this event. The System Operator is also supporting the Authority and MBIE with their own investigations.
- Generation failure at Tuai occurred over the morning peak on 16 August. This was resolved with a demand reduction of 26 MW which was managed by local electricity distribution businesses (EDBs) without any loss of supply.
- HVDC Pole 2 conductor in Weka Pass was damaged by high winds just after 15:00 on 17 August. As a result, a forecast shortfall for the evening peak period was signalled via a Grid Emergency Notice and communicated via an industry conference. Demand response by EDBs using controllable load in the North Island ensured the system was secure and additional generation was made available in subsequent days. HVDC Pole 2 bi-pole service returned at 13:00 on 26 August.
- This same weather pattern of high winds and lightning storms in the South Island early in September contributed to a number of trippings and small service interruptions managed in real time by the control centres. An industry conference was convened, and we were pleased to see support from multiple parties (including Genesis stoking up a Rankine unit at Huntly). Fortunately Pole 2 was returned by 12:30 which, together with the start of lockdown reducing the demand, mitigated the risk and additional North Island generation was not required.
- There were unplanned outages to the Edendale substation on 28 September that caused a loss of service to the Fonterra dairy processing plant and surrounding region for nearly an hour (33 MW). The restoration process included a requirement for emergency switching.
- At 09:22 on 30 September, a tripping at the Kikiwa substation, combined with some planned outages in the region, interrupted service to much of the West coast region (31.8 MW). We worked closely with Westpower and Trustpower

to carry out some reconfiguration which supported restoration and was completed by 10:45.

Recent initiatives

- Demand post-Regional Coincident Regional Peak Demand (RCPD[1]): We completed a survey and analysis to investigate possible increased peak demand which may occur when the RCPD incentive ended. Our analysis indicates we could see an increase of around 300 MW for peak demand periods where load would have previously been controlled. As a result, we have adjusted the peak demand growth assumption in NZGB from 2% to 4%.
- Customer Portal: We launched the first application of our Customer Portal, the new Automatic Under-frequency Load Shedding (AUFLS) portal. This is used to gather yearly 2-block AUFLS feeder load data from North Island distributors, enabling both them and us to view their overall provision and compliance with obligations.
- FSR programme: The Electricity Authority announced the FSR programme of work to industry on 10 August. Phase one of the work programme is on track for Transpower to deliver the draft report outlining future challenges and opportunities to the Authority in mid-October. This report will be released to the industry in mid-November.

[1] The RCPD allocation method under the current Transmission Pricing Methodology creates an incentive for load to be managed across peak demand periods. This ended on 31 August 2021 creating the potential for an increase in peak demand 1 September 2021 compared to historical demand.

System Operator performance

1 Customers and other relationships

Security of Supply Stakeholder Engagement

The System Operator's draft 2021 Security of Supply Annual Assessment has been out for consultation. The assessment provides a ten-year view (2021 - 2030) of the balance between supply and demand in the New Zealand electricity system. It considers both energy and capacity risk and looks at four demand and supply scenarios. This year it also assesses the impact on security of supply margins of increasing proportions of renewable generation. Consultation closed on 5 October. A final version of the report will be published before 29 October.

SOSPA Management

We delivered the System Operator Annual Self-Review for the 2020/21 financial year to the Authority on August. As part of this we reported a score of 100% against the weighted performance metrics for 2020/21 that contribute towards our incentive payment. The Authority are currently carrying out their review of System Operator performance for 2020/21 which will be published later this year.

The annual publication of the Joint Development Programme was prepared and published on the Authority's website in August. This joint obligation includes a combination of the Authority's work programme and the System Operator's capital and investigation work planned across the next five years.

An update to the System Security Forecast (SSF) was published in August which incorporates Tiwai's deferred exit and other new committed assets such as Harapaki wind farm, and transformer replacements such as Edgecumbe and Fernhill. The SSF confirmed that we will be able to meet our Principal Performance Obligations over the next three years. More information is provided in section 8 of this report and greater detail is available on the Transpower website.

The 2021/22 SOSPA audit programme is underway with the Under-Frequency Event (UFE) audit fieldwork in progress and being performed by an independent consultant. The audit will assess whether the System Operator met their Code obligations as well as the internal procedures on two recent under frequency events. The scope does not include the Grid Owner event in 2019.

GM Stakeholder Meetings

Dr Jay has met with a number of Electricity Distribution Businesses and generation companies including PowerCo, Unison, Orion, Electra, WEL, Network Waitaki, Todd Energy, Helio Energy, Genesis Energy and Meridian Energy. He also attended two APEx board meetings and a seminar on Global Wholesale Market Design. A further seminar on the learning from the Texas blackouts is planned for October.

2 Risk & Assurance

COVID-19 response

With the change to COVID-19 alert level 4 across New Zealand on 17 August, the Operations division activated its incident management response team, notified the Authority and commenced regular situational reporting. Under alert level 4 we implemented our planned COVID-19 protocols into our control rooms[2], including restricted access, physical room separation within control rooms, shift bubbles and increased cleaning. We have also been investigating additional protocols such as saliva testing.

We employed other steps to account for changing demand with alert levels, such as adjusting load forecasts, adjusting our reserve management tool parameters for exempt Automatic Under Frequency Load Shedding (AUFLS) industrial load, and reminding participants to inform us of changes to their AUFLS provision and any changes in demand greater than 50 MW.

We have maintained vigilance over the remainder of the quarter to protect our control room staff from the threat of COVID-19. Our incident management team remains active, reporting weekly to the Authority.

The team are working with Health & Safety to develop a recommended approach for the extended-term management of COVID-19 once New Zealand reaches a plateau level of vaccination and lockdown controls are released. This will take a near-term view for what can be done in the short-term as well as some longer-term recommendations that may require investment.

High voltage management

Managing high voltages during trough periods overnight has required additional effort. On 29 August, we switched out 11 circuits to keep voltages to an acceptable pre-contingent limit, as compared to 3 circuits for the same time last year. We will continue to carefully monitor and plan for this, however increasing load due to the reducing COVID-19 national alert levels (excluding Auckland) will improve the situation.

Business Assurance audits

We have started the first of our five business assurance audits for 2021/22, covering our process for determining causer recommendations related to Under-Frequency Events.

[2] Our four Transpower control rooms across New Zealand operate to the highest alert level any one of them is exposed to.

3 Compliance

July

We reported three System Operator breaches in July.

Breach: Incorrect modelling of PAK_WKM2.2 circuit
Event date: 17 March – 30 April 2021
Date reported: 21 July 2021
Description: Values were inadvertently swapped when modelling a change to the PAK_WKM2.2 static limits and impedances. Approximately 1.1 MW of generation per trading period was short-procured during the event period (aggregate market impact $169,116). The error was detected and corrected on 30 April and the existing process document was reviewed and updated in May 2021 to include a new preventive step.

Breach: Slow NRSL solves
Event date: 02:00 on 9 and 10 June 2021
Date reported: 22 July 2021
Description: 02:00 non-response schedule (NRSL) solves took longer than expected to complete and publish due to long solve times for the voltage stability application. The error was rectified by reconfiguring a timer to prevent failed solves re-queueing. The corresponding price responsive schedule was published and there was no market impact.

Breach: Non-publish of NRSS/PRSS
Event date: 11:30 on 15 May 2021
Date reported: 23 July 2021
Description: During a market system failure a pair of non-response and price-responsive short schedules (NRSS/PRSS) auto-triggered and started, were solved, but were not published due to issues associated with the market system switchover. There was no market impact, as the System Operator was still dispatching off earlier schedules.

August

We reported one interim System Operator breach in August.

Breach: Grid emergency load shedding
Event date: 17:00 – 21:00 on 9 August 2021
Date reported: 13 August 2021
Description: The System Operator identified three Code provisions that were potentially breached on 9 August. The System Operator has engaged an external consultant to investigate the event and will not be able to determine if any Code provisions were breached until the investigation is complete.

September

We did not report any System Operator breaches in September.

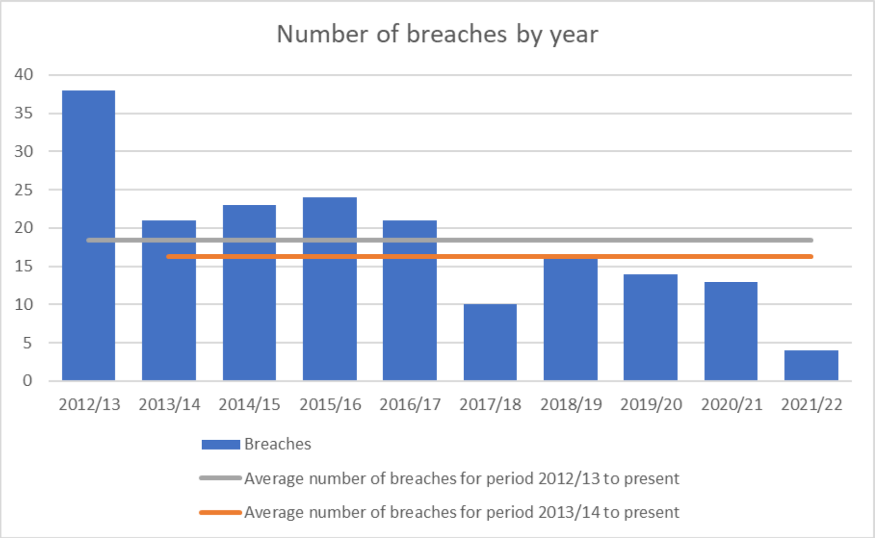
During the month, we received three breach warning/closure letters from the Authority, all with no further action being taken:

Breach: SFT built constraint using an incorrect post-contingent circuit rating
Event date: 15 August – 20 August 2020
Date reported: 30 September 2020
Description: Issue rectified via a Code change to the production system on 20 August 2020. There was no market impact. The Authority's warning letter set out expectations around ongoing compliance with the relevant provision of the Policy Statement.

Breach: Incorrect modelling of electricity risk curve
Event date: March 2020 – March 2021
Date reported: 9 April 2021
Description: Modelling was corrected in March 2021 and the electricity risk curves now include the relevant floors and buffers. There was no market impact. The Authority's warning letter set out expectations around ongoing compliance with the relevant provision of the Security of Supply Forecasting and Information Policy.

Breach: Incorrect modelling of NGB reserves
Event date: 23:30 on 21 January 2021
Date reported: 18 March 2021
Description: Over-procurement of North Island reserves for 70 trading periods (aggregate market impact approximately $40,000 - $93,000). Auto-fresh of the reserve requirements display (tool change) was implemented in August 2021 and the System Operator is currently documenting the end-to-end process (audit of secondary risk management scheduled for Q4 2021/22). The Authority's warning letter set out expectations around ongoing compliance with the relevant provisions of the Code.

We have eight 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.

July

No items were opened in the Register during July.

August

No items were opened in the Register during August.

September

No items were opened in the Register during September.

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
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
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

4.1 Independence recommendations update

Transpower's Risk & Assurance engaged Deloitte to conduct an audit of the breach process managed by the System Operator to ensure impartiality in the end-to-end breach process (Grid Owner vs other participants). An audit of the breach process covers the System Operator inherent independence threat around monitoring the Grid Owner's compliance with the Code. Deloitte commenced the audit in June and delivered a draft Summary of Findings to the System Operator in October. The draft Summary of Findings confirmed a clean audit with no recommendations.

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)
All Phase one defects have now been resolved or scheduled for release.

Phase two work is progressing well in general. Additional resourcing has been assigned to assist with progress on development of one component which has been hindered by increased childcare impacts associated with the COVID-19 lockdown; this work is not on critical path. Completion of SCADA Data Validation (SDV) development has taken seven weeks longer than originally forecast with delays managed so as not to affect the critical path by testing components as they become available. All development work for Phase 2 is now complete and testing is well underway. Business procedure reviews and updates, and training development continue to progress as planned.

Phase three work on component design, detailed requirements, user interface and business processes are in progress. Requirement validation and system functional requirement workshops continued through the quarter.

Inter-project scheduling and environment conflicts continue to be monitored with no significant issues arising.

The August industry engagement session was fronted by NZX talking about changes to the WITS trading platform. Work is now underway on the final two webinars of this engagement cycle which will focus on demand-side market changes.

Extended Reserves (Automatic Under Frequency Load Shedding - AUFLS)
In July, we launched the first application of our customer portal, which will eventually replace existing separate external databases with a single portal. The first application released on the customer portal is the new AUFLS data portal. This will be used to gather yearly 2-block AUFLS feeder load data from North Island AUFLS providers, enabling both them and Transpower to view their overall provision and compliance with obligations. This provides a better view of how much AUFLS is armed at any given time, allowing adjustments to minimise the risk of over-tripping load. The data will also form a baseline for consideration when transitioning to the future 4-block AUFLS system. A total of four training sessions have been provided in July and September to the end users to date and were well received.

During August, we largely onboarded the affected North Island AUFLS providers onto the AUFLS application in the customer portal. One of the affected parties, Eastland Network, remains to be onboarded. After the Authority contacted Eastland Network, they have confirmed they will be in touch to make the necessary arrangements with the System Operator to onboard their users and are aware they have to provide the required information by early November. The next training workshops are scheduled for 15 and 16 November. These sessions will focus on uploading the load data during the next AUFLS submission period starting January 2022.

In August, the Electricity Authority published its decision on the extended reserve Code consultation after which we began the System Operator consultation on the AUFLS Technical Requirements (ATR) document. The ATR Document details the performance and compliance requirements of a 4-block AUFLS scheme to be connected to the power system in the North Island to meet the Code obligations set out in Part 8, Technical Code B – Emergencies. In meeting these obligations, the System Operator can plan to comply, and comply with its Principal Performance Obligations. The consultation period closed on 17 September. The team are reviewing the submissions and make final updates to the ATR document, which will be submitted to the Authority in October.

5.2 Other projects and initiatives

Continuous Business Improvement Initiatives

Initiative	Activity Completed	Improvement Implementation
System Security Forecast (SSF) Report Evaluation	An evaluation is underway on the System Security Forecast report that the Electricity Industry Participation Code stipulates the System Operator must publish every two years and update every 6 months. The purpose of this evaluation is to: • Reduce the time spent by the Power System engineers to complete the reporting by improving the reporting study analysis and creation process. • Ensure that the SSF delivers on its 'purpose' considering changes happening to the NZ Power System. i.e. the SSF that was fit for purpose over the last 10 years may not be suitable for the next 10 years given the ever-changing environment we are operating in.	Completed June – September 2021 • Current-state process currently taken to complete the SSF report. • Customers Survey – validate who consumes the information, which parts of it and what actions are taken/informed by the content. • Analytics of current report – how many customers have accessed which sections of the report. • Ideation workshops – surfacing options for production and implementation of the SSF report. Solution option analysis is well underway and an evaluation report with recommended improvements will be produced late November 2021.

6 Technical advisory hours and services

Future Security & Resilience (FSR)

On 10 August, the Electricity Authority announced the FSR programme of work to industry. Phase one of the work programme is a draft report outlining future opportunities and challenges to power system security and resilience and the draft report will be delivered to the Authority in mid-October. Sapere have been engaged to undertake an independent review of the report prior to it being finalised. The Authority and Sapere are currently undertaking this review and it will be released to the industry in mid-November.

Upcoming TAS work

TAS work relating to Battery Offering Reserves (TAS100) was approved in early October and the December 2019 UTS (TAS101) is in the final stages of approval.

The following table provides the technical advisory hours for Q1 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 Q1
TAS SOW 95 – Battery Energy Storage Systems Offering Reserve	Complete	13.5
TAS SOW 97 – RTP engagement session support	In progress	58.8
TAS SOW 98 – AUFLS Data Portal Deployment to NI Distributors	In progress	225.0
TAS SOW 99 – Future Security & Resilience	In progress	786.8
TAS SOW 100 – Battery ESS Offering Reserve	In progress	215.5
Total hours		**1,299.6**

7 Outage planning and coordination

Outage Planning – near real time

Outage numbers and consequent assessment volume reduced as we entered the winter period. However, the COVID-19 level 4 lockdown led to increased outage changes and uncertainty, with the Grid Owner and distributors postponing and re-planning work. We anticipate increased workloads in October and November as a result.

New Zealand Generation Balance (NZGB) reporting

In the August report, we changed the load growth factor applied to NZGB for the period 1 September 2021 to 31 August 2022 from 2% to 4% to reflect possible changes to load management practices when Regional Coincident Regional Peak Demand (RCPD[3]) incentives within the transmission pricing methodology are removed.

Throughout the quarter the New Zealand Generation Balance Reports forecast no N-1-G shortfalls for the base scenario for the next six months. In July, applying low gas and no wind assumptions, minor N-1-G shortfalls were forecast in mid-August, early

[3] The RCPD allocation method under the current Transmission Pricing Methodology creates an incentive for load to be managed across peak demand periods. This will end on the 31 August 2021 creating the potential for an increase in peak demand from 1 September 2021 compared to historical demand.

September and early October. When applying low gas, no wind assumptions to the base scenario in October, only a single N-1-G shortfall is forecast on 28 October.

There was an industry conference on 19 August to provide an update on recent market events, progress on the restoration of the HVDC Pole 2 and to give an update on issues affecting outputs from the NZGB tool. Slides presented on NZGB are available on the Transpower website.

Outage Planning events or items of note
In September, we published analysis of the power flow limits following completion of the Clutha and Upper Waitaki Lines Project (CUWLP). These are approximate transfer limits and indicative constraints that will apply once the duplexing work is complete.

8 Power systems investigations and reporting

Operational impact of Tiwai exit
This work continued this quarter. A page on the Transpower website has been developed 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.

System Security Forecast (SSF) update
This quarter we published the six-monthly SFF update which incorporates Tiwai's deferred exit and newly committed generation projects and grid upgrades since the major report was published in December 2020. Changes include the newly committed Harapaki wind farm, and transformer replacements such as Edgecumbe and Fernhill.

The analysed asset changes have resulted in a number of security issues being resolved, and two new N-1-1 [4] issues to manage due to the new Bombay interconnecting transformers. In addition, the Wilton double tee grid reconfiguration has an overall net benefit on the limits for both north and south flow on the HVDC

More detail is available on the Transpower website.

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.

[4] A. When HLY-DRY 1 220 kV circuit or the HLY-TAK-OTA 2 220 kV circuit is on outage and the other trips causing a Bombay-Hamilton circuit to overload. This occurs as one of the Bombay-Hamilton circuits is disconnected as part of the Bombay interconnection grid upgrade.
B. When the DRY-TAK-OTA 1 220 kV circuit is on outage and a BOB-WIR-OTA 110 kV circuit trips overloading the other. This is a by-product of having more power injected into the Bombay 110 kV system.

		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	0	5
	Bite-sized Market Insights	≥ 45	9	
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	0	10
Breaches creating a security risk - below threshold/within acceptable range		≤2	0	10
On-time SOSPA deliverables		100% (50)	100% (5)	10
Successful project delivery				
Project delivery	Service Maintenance projects	≥ 70% on time	0 completed	
		≥ 70% on budget	0 completed	
	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	100%	5
High spring washer resolution		80% ≤ 10am or equiv	0 to date	
Fit-for-purpose tools				
Capability functional fit assessment score		76.00%	N/A	
Technical quality assessment score		70.00%	N/A	
Sustained SCADA availability		99.90%	99.99%	10
Maintained timeliness of schedule publication		99.00%	99.99%	10

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.

Below are instances of variations we have observed this quarter

Energy

Overall industry performance this quarter – July to September 2021

- *Discretion – 100% binding constraints (July)*
  - July is often a period of seasonal stress due to high demand

- *Discretion applied under 13.70 to meet dispatch objective (August and September)*

  <u>August</u>
  - In a number of cases Whirinaki was discretioned to a minimum of 10 MW for security
  - There was planned switching at Argyle
  - Discretion was applied when the Berwick-Waipuri circuit tripped

  <u>September</u>
  - The majority of the cases when discretion was applied were during periods of adverse weather
  - There were also cases where discretion was applied at Whirinaki and Huntly unit 5 to meet their dispatch minimums

- *HVDC modulation beyond 30 MW band (July)*
  - This behaviour is also seasonal, which can be seen in July 2020, reflecting changes as generators ramp up and down

- *Total constrained on - All sources (September)*
  - Reflects the period when Turitea was commissioning

Optimal dispatch this quarter

There is no notable variation of the optimal dispatch metrics during this period.

Reserves

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

- The amount of interruptible load armed, as opposed to that offered and used as an input into RMT (and then dispatched by SPD).

- The influence of the type of generation on the amount of net free reserves available.

Observations this quarter – July to September 2021

- *Proportion of time DCCE[5] is risk setter (August)*
    - This is the key observation from this period as it is the first time since the HVDC outage that DCCE has been the risk setter. In this quarter it was triggered by an unplanned outage following adverse weather conditions.

- *Proportion of time DCECE[6] is risk setter (September)*
    - This occurs when there is a commissioning risk and a low ACCE risk as was the case during Turitea commissioning

- *Average MW risk when risk setter*
    - This is highlighted for DCCE and DCECE over this quarter period. This compares to the majority of the time when they are not risk setters; hence when they are risk setters with non-zero MW, these are highlighted as higher than the usual 0 MW risk

- *SIR procured (MW) and ($) (July and August)*
    - Although the amount of SIR increased over the period, the greater variation is in the cost due to SIR being priced highly over this period

10 Cost-of-services reporting

We will provide the Authority with a final report on the cost-of-services for financial year 5 (2020/21) towards the end of 2021.

[5] 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.
[6] This is an event due to the loss of the HVDC bipole for which, in the reasonable opinion of the system operator, resources are only able to be economically provided to maintain the security of the grid system and power quality **by** disconnecting some demand

11 Actions taken

The following table contains a full list of actions taken during Q1 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**:	• Partner with the Electricity Authority to develop a future security and resilience roadmap and appropriately resourced work programme *Phase one of the work programme is on track for Transpower to deliver the draft report outlining future challenges and opportunities to the Authority in mid-October.* • Include a low carbon scenario in the Security of Supply Annual Assessment *The current 2021 consultation assesses the impact on security of supply margins of increasing proportions of renewable generation* • Continue to deliver our customer portal replacing older external applications unlocking improved capability *The first application released is the new AUFLS portal. This will be used to gather yearly 2-block AUFLS feeder load data from North Island distributors, enabling both them and Transpower to view their overall provision and compliance with obligations.*
(ii) To comply with the **statutory objective work plan**:	• Evaluate and revise performance metrics, targets and incentive payment calculation *We are currently seeking advice from an external consultant on developing KPIs that will drive the operationalisation of our Ambitions and will feed into the revised performance metrics piece of work*
(iii) In response to participant responses to any **participant survey**:	**Feedback from the 2020-21 survey** • Would like to see “Lessons learnt on projects, near misses. engagement with industry “ *This year these have been included in the Annual Self-Review* • “a more forward looking approach would be helpful” *This is also the driver for the Ambitions work and the FSR work we are providing assistance to the Authority on*
(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

At the end of September, national hydro storage is was 136% of average for the time of year, which is above the 90th percentile of historic averages. This follows three months of unseasonably heavy rainfall in the South Island which is uncharacteristic for a time of year where we would generally expect to see less rain and more snow. The conditions have enabled the country to recover quickly from the potential dry scenario earlier in the year.

As a result, hydro generation has been high and there has been very low southward transfer across the HVDC. Correspondingly thermal generation has been low, and for the period between 01:00 and 04:00 on Friday 17 September there was no thermal generation on the New Zealand power system (although there was still co-generation). As a result, the New Zealand power system was operating on 96% renewable energy for nearly four hours.

Wind generation has been variable throughout the quarter. In the latter half of August it was high, comprising 8% of the generation mix for the week ending 22 August and 7% for the week ending 29 August. However, the variability in wind generation has resulted in some tight evening peaks; this has been particularly noticeable with less baseload thermal generation running.

Cold weather across the country lead to a new national peak demand record on Monday 9 August when demand reached an instantaneous peak load of 7,187 MW at 18:23 (the hour-hourly average for this period was calculated as 7,080 MW). Over this peak period there was insufficient generation to meet demand resulting in the System Operator instructing load to be shed. The load shedding incident is subject to a number of investigations, more details are provided in section 15 of this report.

With Contact Energy's Taranaki Combined Cycle plant (TCC) and Genesis' third Rankine at Huntly not offering in the market through August, energy margins over peaks have been tight for a number of peak demand periods. This was communicated to the market through the established Standby Residual Check and Low Residual Notices.

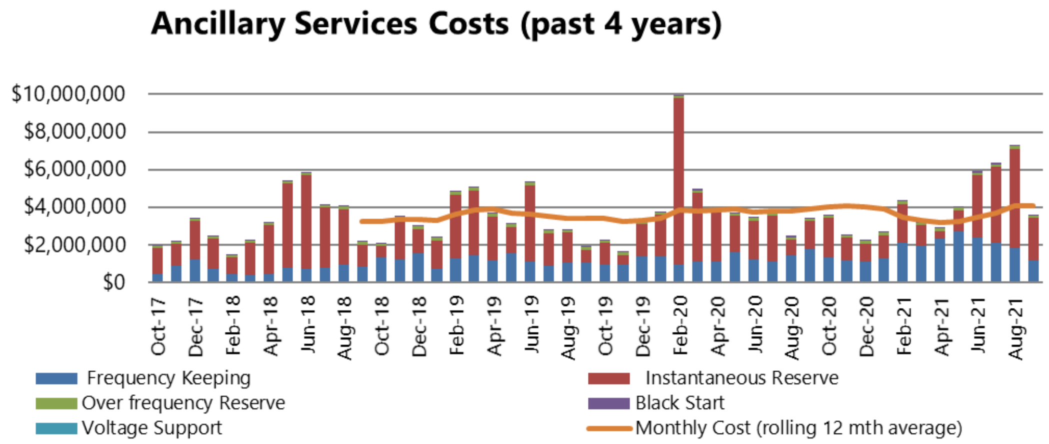
On 19 August, an unplanned outage of Pole 2 again challenged supply security, but was managed by co-ordinated controllable load reduction by distribution companies

Demand has varied with changes to COVID-19 national alert levels. Following the country (excluding Auckland) moving to alert level 3, demand has gradually risen which we assume reflects business progressively resuming.

Improved hydro storage levels coupled with periods of strong wind and the onset of the COVID-19 national alert level 4 lockdown in August contributed to a drop in the average price at Haywards. Weekly average prices since mid-August have regularly been between $50-$100/MWh. This is down from an average price for May of $280/MWh which was seen in the midst of this year's dry scenario, when hydro storage was well below average.

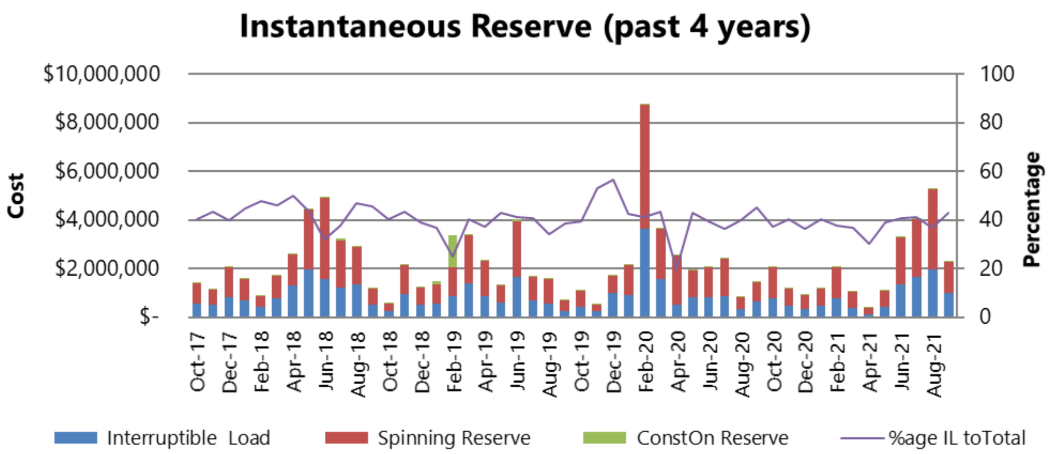
Inter-island price separation was experienced in late July and August due to HVDC constraints and outages. This was resolved when Pole 2 returned to service on 26 August. Outages in the lower South Island in late-September resulted in price separation with close to $0/MWh behind the constraints.

13 Ancillary services



This quarter's ancillary service costs were $17.3 million, which is a 34 per cent increase compared to the previous quarter's costs of $12.9 million. The majority of these costs were in the first two months of the quarter.

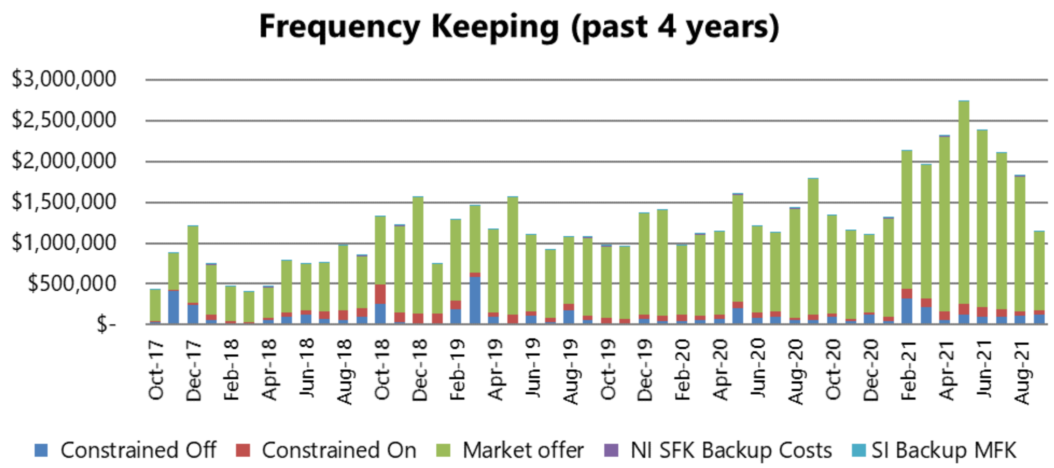
In July and August, while the cost of frequency keeping fell slightly, the overall costs rose due to a significant increase in costs associated with instantaneous reserves. The overall costs in September were much lower, $3.6 million, a 50% decrease to the previous month's costs of $7.3 million. This pattern is expected as we move into Spring.



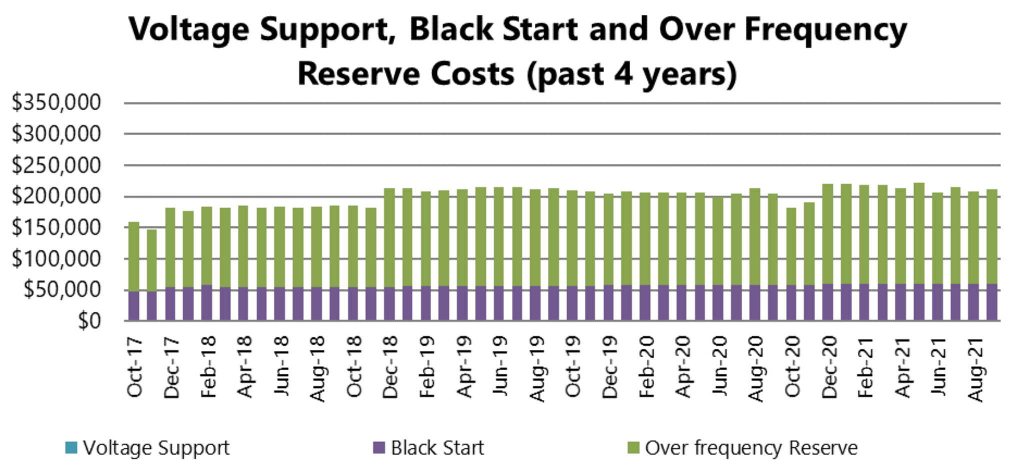
This quarter, the instantaneous reserve costs were $11.6 million, which is a 142 per cent increase to the previous quarter ($4.8 million). Interruptible load costs increased by $2.7 million (142 per cent increase), spinning reserves increased by $4.1 million (143 per cent increase) and constrained on costs increased by $13k (32 per cent increase).

In July, despite a slight decrease in the quantity on instantaneous reserves procured, the major contributor to this month's increase in costs was a significant jump in the average price for sustained instantaneous reserves in both the North and South Islands (an average increase of $4.9k in the North Island and $4.5k in the South

Island). In August, we saw a slight increase in the quantity of North Island fast instantaneous reserves procured. However, the major contributor to this month's increase was a significant jump in the average price for fast instantaneous reserves in the North Island. In September, we saw a slight decrease in the quantity and average price of South Island instantaneous reserves. However, the major contributor to this month's decrease was a significant drop in the quantity and average price for North Island instantaneous reserves.



This quarter the frequency keeping costs were $5.1 million, which is a 32 percent decrease compared to the previous quarter's costs of $7.4 million. In comparison to the previous quarter the North Island frequency keeping costs fell by 39 percent while the South Island costs fell by 11 percent. Frequency keeping costs have declined month-on-month since the high in May with costs falling in both the North and South Islands.

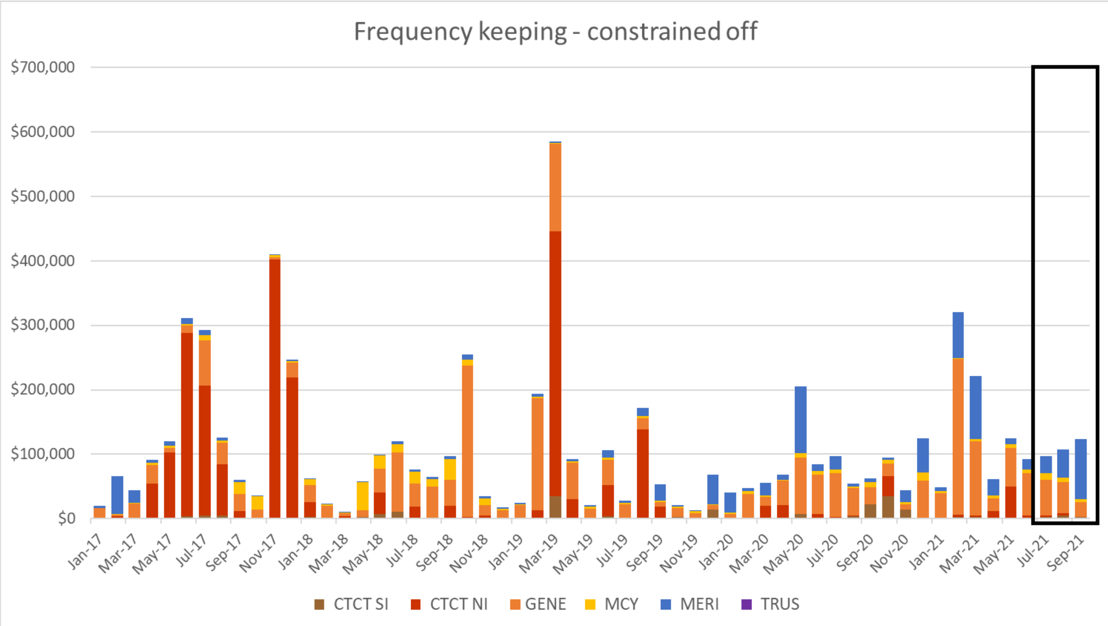


This quarter, there was no variance to the black start costs and only a slight decline in over frequency reserve costs due to equipment outages causing reductions in availability fees. There are no voltage support costs as we do not currently procure this service.

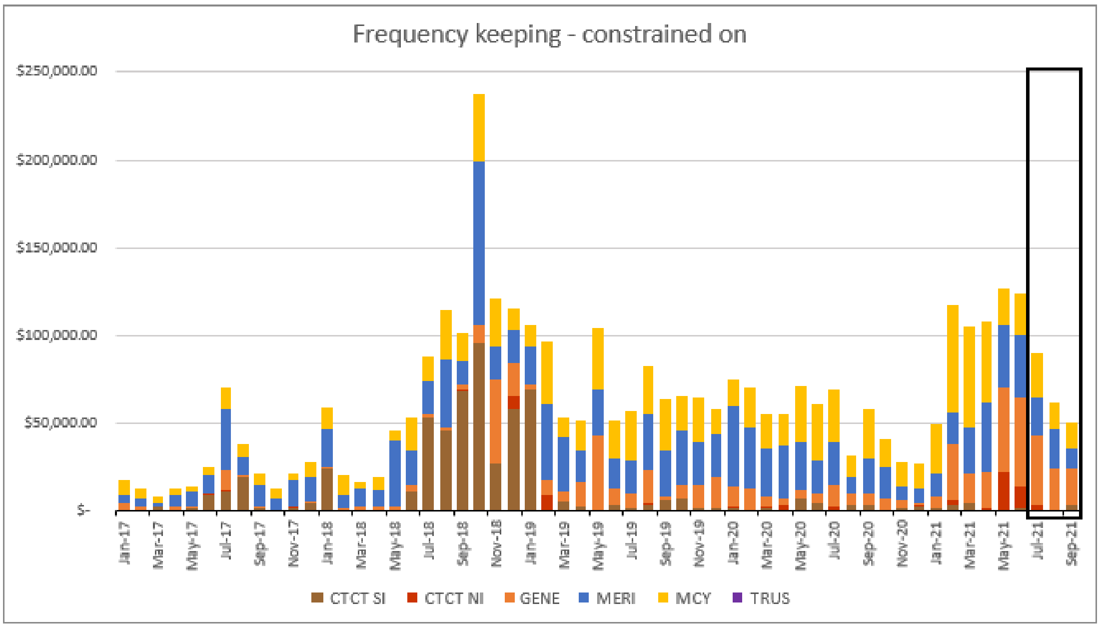
Constrained on/off costs

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

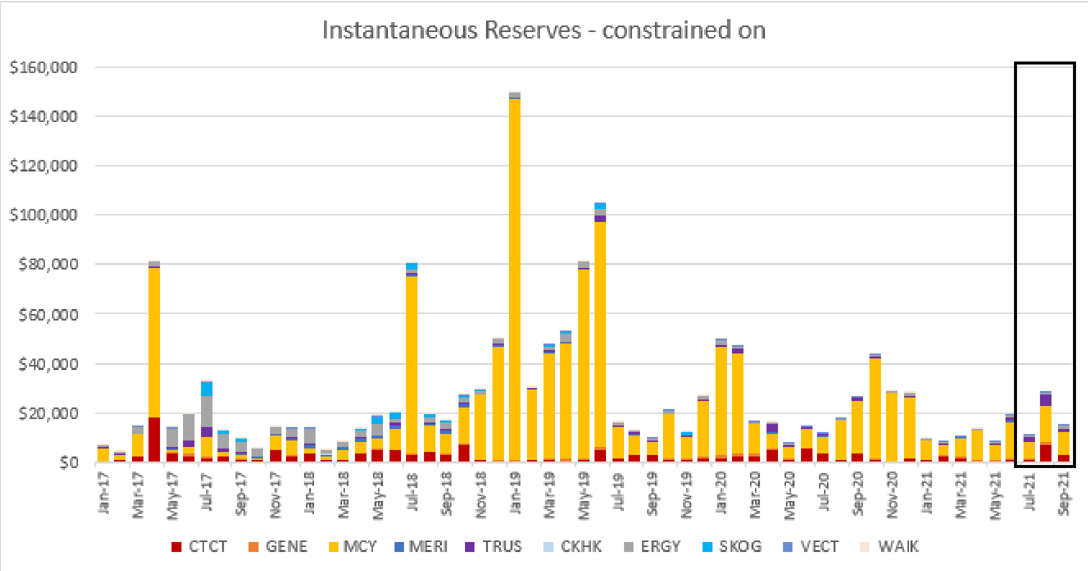


For 2021/22 Q1, the frequency keeping constrained off costs increased by 17% on the previous quarter to $327k. Despite the North Island constrained off costs falling by $70k (30% decrease), the South Island costs rose by $118k (319% increase) resulting in a net increase.



For 2021/22 Q1, the frequency keeping constrained on costs decreased by 44% on the previous quarter to $202k. The North and South Island frequency keep constrained on costs fell proportionally (41% and 43% decrease respectively) since the previous quarter.

Instantaneous Reserves



For 2021/22 Q1, the instantaneous reserves constrained on costs were 33% higher than the previous quarter reaching $53k. However, $53k is very consistent with 2020/21 Q1 instantaneous reserves constrained on costs of $55k.

14 Commissioning and Testing

Generation testing and commissioning

Turitea Wind Farm started commissioning its first turbines at the end of July. It is expected commissioning of the full station (118 MW) will run through until November 2021.

15 Operational and system events

July

Preparing for weather-related service interruptions

Ahead of the severe storm warning for the weekend of 17 July, both control rooms worked proactively to prepare in the event of potential weather-related service interruptions. We responded to multiple alarms triggered by weather-related events in distribution networks, particularly in the Rotorua/Bay of Plenty region, and the West Coast of the South Island.

Uninterruptible Power Supply (UPS) fault and fire

Another event to note, although not directly related to the System Operator function, was the recent live test of the Transpower business continuity plan when an evacuation of the Auckland control centre was required as a result of a UPS fault and fire. The fire alarm activated on shift change and the Fire Service were automatically dispatched as soon as the alarm was triggered. Routine evacuation protocols were followed, and all operational duties were switched to Christchurch (the other control room operating in the same capacity). The Christchurch team switched over the phones and started to assess current state to enhance their situational awareness. The decision was made to call in support which meant we could carry out all planned work throughout the country while the UPS was isolated, power restored, and the Auckland Control Room made habitable (smoke extracted and surfaces cleaned down). This was a very good response from all the team involved. As always, there are a few things that can be learned and improvement opportunities identified, and these will be considered once we have completed our review.

August

9 August demand management event

On 9 August, the System Operator forecast and communicated a residual shortfall over the evening peak. As the country approached the evening peak, Tokaanu generation experienced an unplanned reduction in output due to weed affecting operations. This incident coincided with a significant reduction in wind generation; the result was a generation shortfall. Coupled with high levels of demand and no further available generation offered, the residual shortfall became too large and frequency could not be maintained. This resulted in a Grid Emergency being declared to rebalance the system and increase overall security in order to avoid the potential activation of AUFLS should a contingent event have occurred during the shortfall period. An instruction to reduce demand was issued to all connected parties resulting in some consumers being disconnected. The prompt action and immediate response by most electricity distribution businesses (EDBs) averted a potentially more widespread event.

An independent investigator has been engaged by Transpower to review and report on this event. The System Operator is supporting the Authority and MBIE with their investigations.

16 August Hawkes Bay Grid Emergency Notice (GEN)

To resolve a generation failure at Tuai over the morning peak on 16 August (07:37-08:00), local EDBs managed a demand reduction of 26 MW through a combination of discretionary load, local generation, and load redirection without loss of supply.

17 August HVDC Pole 2 Failure

On 17 August, severe weather in Weka Pass in the Upper South Island caused damage to transmission towers and conductors and resulted in unavailability of HVDC Pole 2 from 15:12. Without Pole 2 in place, a forecast shortfall for the evening peak period was signalled via a GEN and further communicated via an industry conference. Communications included signalling of the required bi-pole outages needed to complete repairs. Weather conditions and COVID-19 restrictions made for a highly challenging restoration. However, response by EDBs using controllable demand and additional North Island generation made available on subsequent days ensured a stable system. The HVDC Pole 2 bi-pole service returned at 13:00 on 26 August without any loss of power.

September

9 August demand management event

We are continuing to respond to requests from the various investigations into the 9 August event:

- We received and responded to the Electricity Authority's immediate assurance review of our management of the event in our role as System Operator. Our response was comprehensive and supportive of the Authority's recommendations and we have established a team to deliver the recommendations.
- We supported the independent review of the event being carried out by PBA Consulting.
- We have responded to review questions requested by the Ministry of Business, Innovation and Employment (MBIE).

Weather-related events

High winds and lightning storms in the South Island early in September contributed to a number of trippings and small service interruptions managed in real time by the control centres. This same weather pattern led to a tripping of Pole 2 at a location near the previous incident in Weka Pass causing concern for management of the power system. An industry conference was convened, and we were pleased to see support from multiple parties (including Genesis firing up a Rankine unit at Huntly). Fortunately Pole 2 was returned by 12:30, which together with the start of lockdown reducing the demand, mitigated the risk and additional North Island generation was not required.

Edendale power outage

Control rooms worked effectively together on 28 September to manage unplanned outages to the Edendale substation that caused a loss of service (33 MW) to the Fonterra dairy processing plant and surrounding region for nearly an hour. The restoration process included a requirement for emergency switching. The underlying fault was an error in the SCADA data indicating that a circuit breaker was open but observed by the controllers to show energy flow.

West Coast power outage

At 09:22 on 30 September, a tripping at the Kikiwa substation, combined with some planned outages in the region, interrupted service to much of the West coast region (31.8 MW). We worked closely with Westpower and Trustpower to carry out some reconfiguration which supported restoration and was completed by 10:45.

Hamilton control centre local power outage

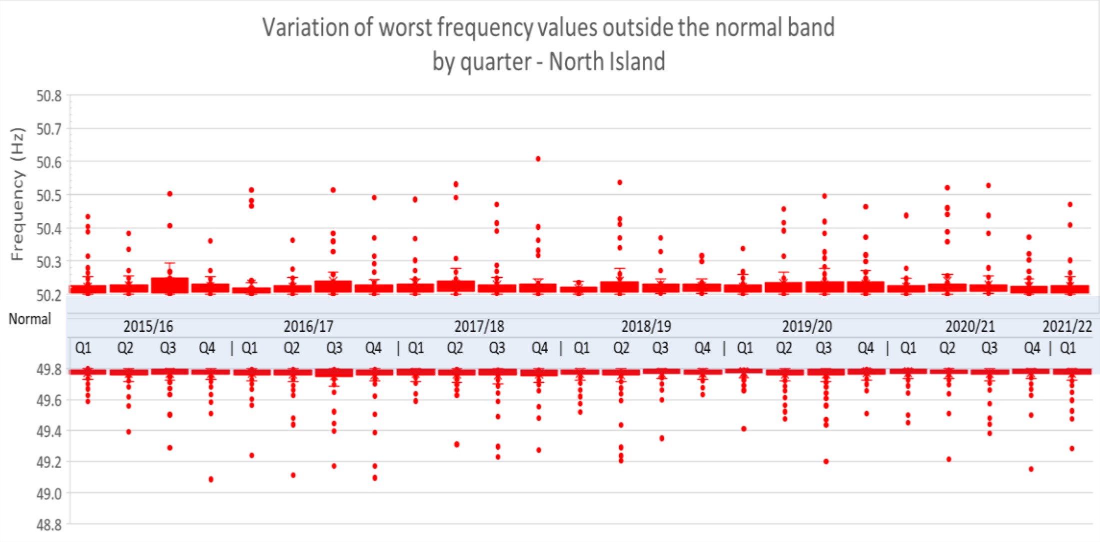
Hamilton control centre were briefly interrupted with a local power outage (due to an action by the electrical contractors on site). The team moved quickly to establish back-up operations including use of our COVID-19 separated desk and standby resourcing in Wellington.

16 Frequency fluctuations

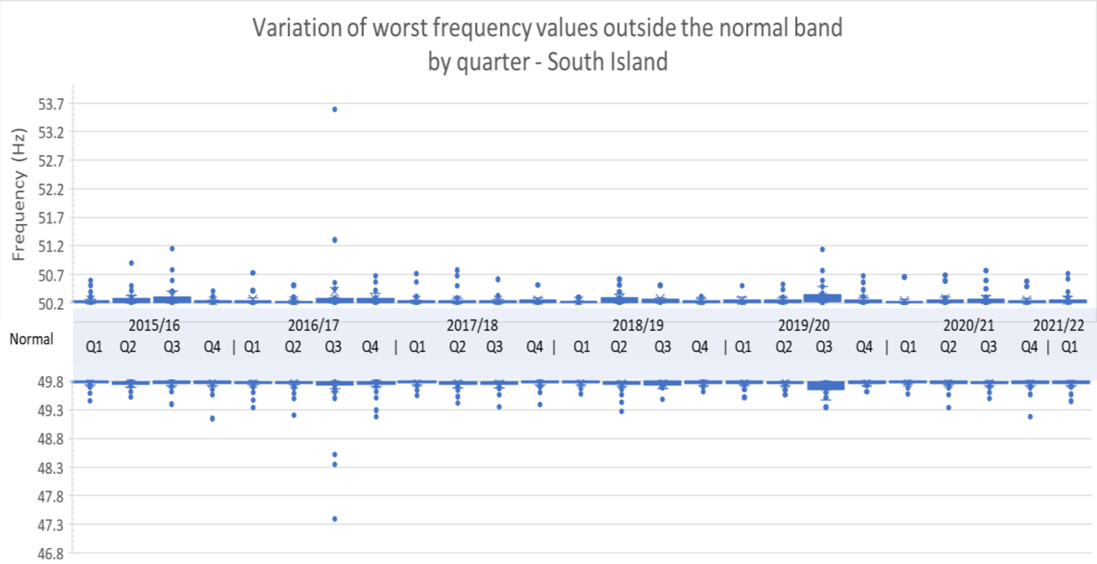
16.1 Maintain frequency in normal band (Frequency value)

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

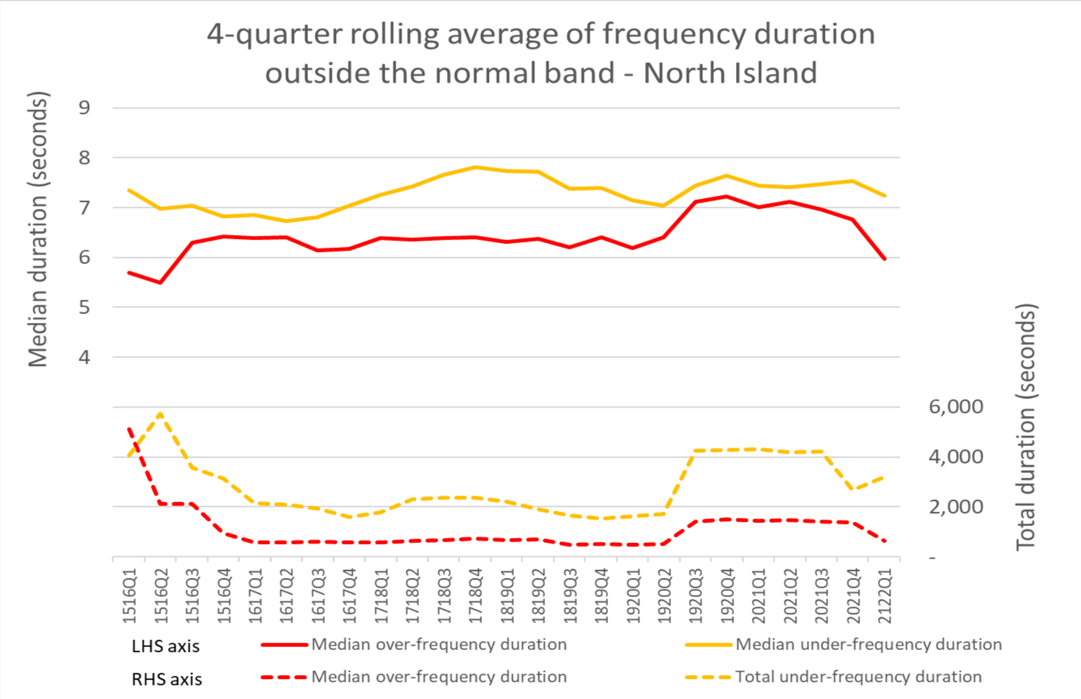


Note: These box and whisker charts show the distribution of data. The “box” represents the distribution of the middle 50% of the data, the “whiskers” indicate variability, and outliers are shown as single data points.

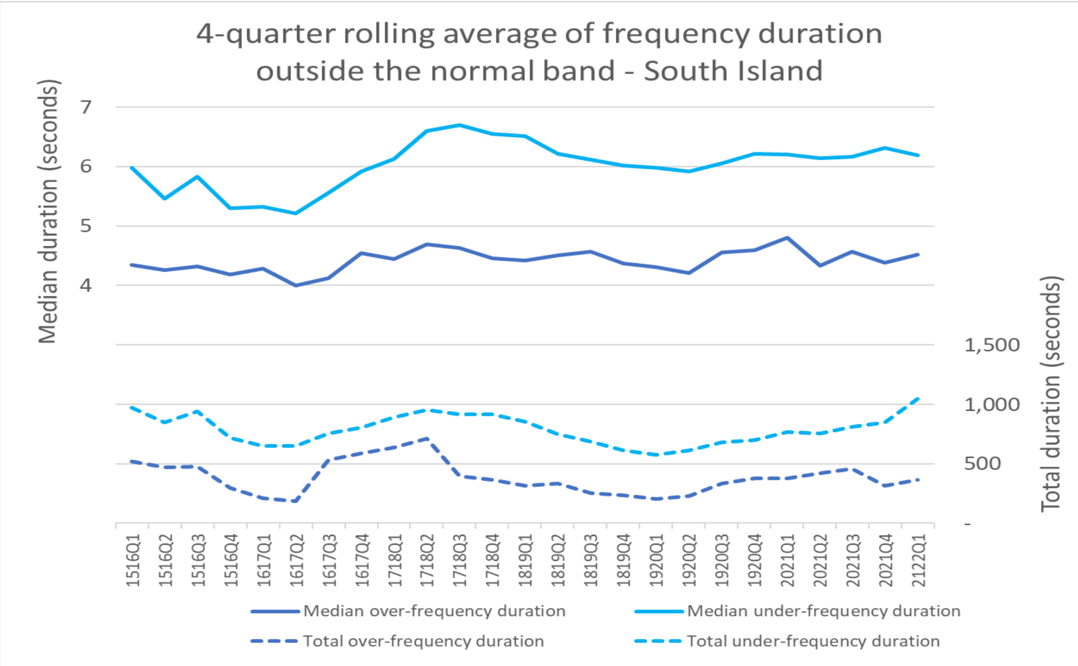
16.2 Recover quickly from a fluctuation (Time)

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



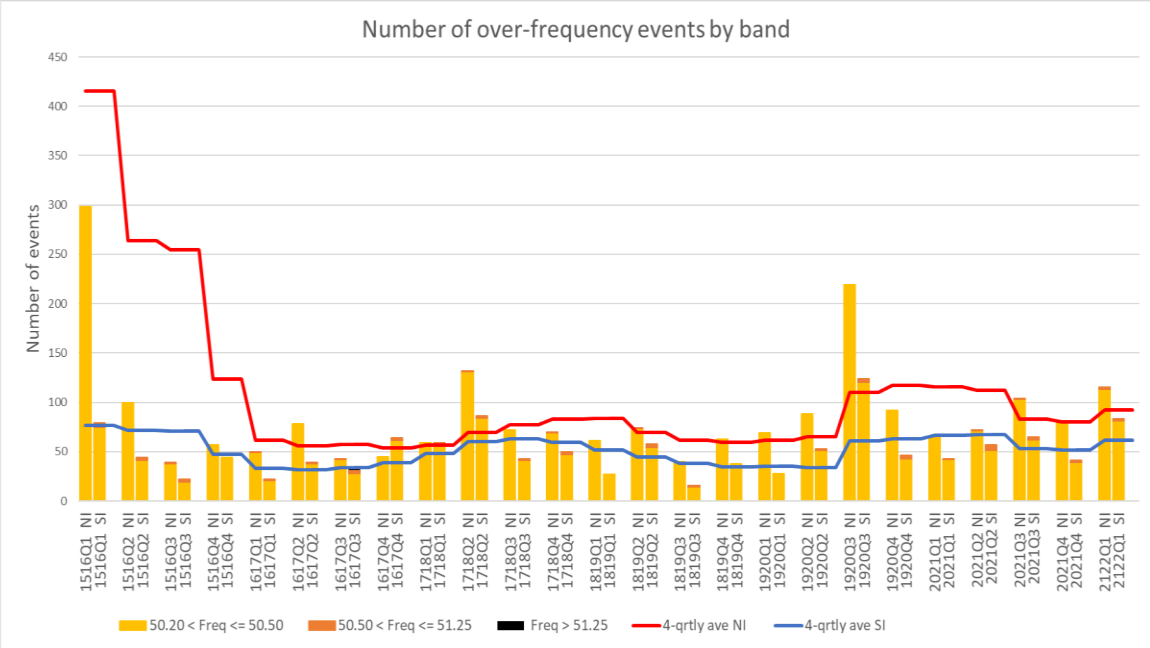
South Island



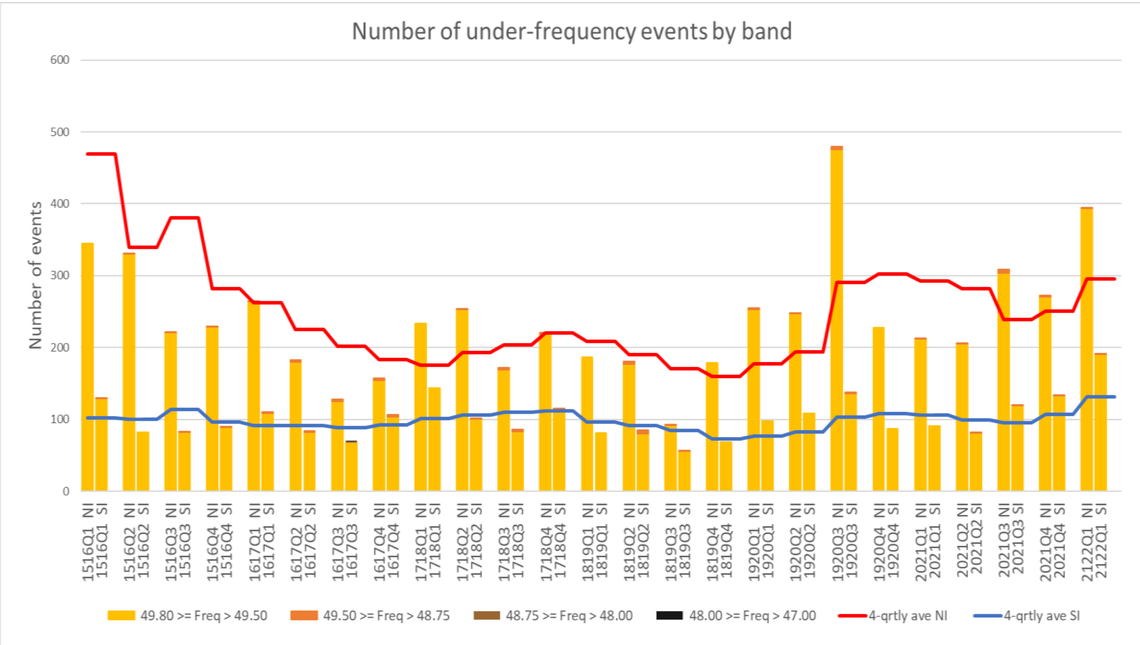
16.3 Manage frequency and limit rate of occurrences during momentary fluctuations (Number)

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. 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	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21
Demand Allocation Notice	-	-	-	-	-	-	-	-	-	-	1	-
Grid Emergency Notice	1	-	2	-	1	1	-	-	1	-	4	2
Warning Notice	-	-	-	-	1	-	-	-	-	1	4	-
Customer Advice Notice	6	12	10	8	4	4	8	14	14	11	42	34

19 Grid emergencies

The following table shows grid emergencies declared by Transpower as System Operator from July to September 2021.

Date	Time	Summary Details	Island
09/08/21	18:00	A grid emergency was declared due to insufficient generation offers to meet national demand.	N + S
10/08/21	07:30		
16/08/21	07:37	A grid emergency was declared due to insufficient transmission capacity to meet Hawkes Bay demand.	N
17/08/21	17:00	A grid emergency was declared due to insufficient generation offers to meet North Island demand.	N
28/09/21	16:22	A grid emergency was declared to assist with the restoration of load at Edendale following a tripping of the 110 kV bus.	S
30/09/21	09:42	A grid emergency was declared to assist with the restoration of connection to the West Coast and Buller regions following a tripping of the 110 kV bus at Kikiwa.	S

Appendices

Appendix A: Discretion

July

Event Date & Time	Event Description
5/07/2021 02:01	MAN2201 MAN0 Discretion Max: 600 Discretion applied to MAN to allow room for TWI L3 185 MW restoration. Last Dispatched MW: 788
8/07/2021 00:57	MAN2201 MAN0 Discretion Max: 556 For the restoration of a TWI extended offload to return. Last Dispatched MW: 738
12/07/2021 02:02	MAN2201 MAN0 Max: 605 To manage TWI Line 3 Extended Offload Restoration. Last Dispatched MW: 788
15/07/2021 01:52	MAN2201 MAN0 Max: 554 Manage TWI Line 3 Extended Offload Last Dispatched MW: 738
17/07/2021 13:36	SFD2201 SPL0 Discretion Min: 160 Due to plant safety. Last Dispatched MW: 134
17/07/2021 20:04	SFD2201 SPL0 Discretion Min: 160 Claim 13.82 minimum running range 160 MW Last Dispatched MW: 126.92
19/07/2021 01:48	MAN2201 MAN0 Max: 555 For the restoration of a planned extended TWI offload to return. Last Dispatched Mw: 738
22/07/2021 03:00	MAN2201 MAN0 Discretion Max: 556 Restoration of TWI L3 Last Dispatched MW: 738
26/07/2021 14:23	HLY2201 HLY5 Discretion Min: 190 Rule Claim on 13.82a, breach of resource consents if running below 190 MW. Last Dispatched MW: 187.0. Discretioning HLY U5 on was the least cost market option as per SC market impact study. HLY U5 also currently importing approx 130 MVArs as part of Upper North Island reactive reserve support.

August

Event Date & Time	Event Description
02-Aug-2021 17:52	WHI2201 WHI0 Discretion Min : 10 Minimum run 10MW, required due to low residual. Last Dispatched MW: 5.21
02-Aug-2021 18:10	WHI2201 WHI0 Discretion Min : 10 Low residual, minimum run 10MW. Last Dispatched MW: 9.76
09-Aug-2021 17:01	WHI2201 WHI0 Discretion Min : 10 Keep on minimum for security over PMPK. Extended until duration of the GEN i.e 21:00. Last Dispatched MW: 45.6
09-Aug-2021 20:38	WHI2201 WHI0 Discretion Min : 10 Change of the type of Discretion from 'Total Capability' to 'Energy Only' .Last Dispatched MW: 10
10-Aug-2021 07:00	WHI2201 WHI0 Discretion Min : 10 Required for morning peak security of supply. Last Dispatched MW: 25
12-Aug-2021 08:46	ARG1101 BRR0 Discretion Max : 0 Planned switching. Last Dispatched Mw: 11.5
12-Aug-2021 09:19	ARG1101 BRR0 Discretion ended following completion of planned switching.
13-Aug-2021 11:27	ARG1101 BRR0 Discretion Max : 0 Planned switching. Last Dispatched MW: 10.0
13-Aug-2021 11:51	ARG1101 BRR0 Discretion ended following completion of planned switching.

Event Date & Time	Event Description
17-Aug-2021 16:32	BWK1101 WPI0 Discretion Max : 0 BWK_WPI tripped, BWK unable to generate onto the grid. Last Dispatched MW: 8
17-Aug-2021 16:33	HWB0331 WPI0 Discretion Max : 0 BWK_WPI tripped, discretion applied but removed before being dispatch as not required. Last Dispatched MW: 2
23-Aug-2021 18:20	WHI2201 WHI0 Discretion Min : 10 SC requests WHI remain on at minimum 10 MW over PM Peak. DC at Capacity, wind at 250, residual at 390. Last Dispatched MW: 25

September

Event Date & Time	Event Description
5-Sep-2021 19:21	ARG1101 BRR0 Discretion Max : 0 Last Dispatched MW: 11.5. Discretioned to 0MW for ARG_BLN_1 switching for ARG_KIK_1 outage.
8-Sep-2021 06:25	WHI2201 WHI0 Discretion Min : 10 Spike in the NIPS. Currently -40MW off dispatch. Frequency keeper outside of their band. Latest dispatch wanting WHI 8.5MW at $550. Agreed with SC to discretion WHI on for the remainder of this TP and next to minimum of 10MW Energy. Last Dispatched MW: 0
8-Sep-2021 07:56	WHI2201 WHI0 Discretion Min : 10 Intermittent generation trending down. Residual around 150MW. WHI was being dispatched reserves on merit, but energy dispatch was below their min running range. Applied discretion to WHI again to hold them at min 10MW energy for remainder of this TP. Last Dispatched MW: 29.71
9-Sep-2021 20:05	STK0661 COB0 Discretion Min : 8 Maintain N-1 Security during adverse weather Last Dispatched MW: 1
9-Sep-2021 20:06	KUM0661 KUM0 Discretion Min : 3 Maintain N-1 Security during adverse weather Last Dispatched MW: .69
9-Sep-2021 21:00	STK0661 COB0 Discretion Min : 4 Maintain N-1 Security during adverse weather Last Dispatched MW: 8
9-Sep-2021 21:00	STK0661 COB0 Discretion Max : 4 Maintain N-1 Security during adverse weather Last Dispatched MW: 8
9-Sep-2021 21:06	STK0661 COB0 Discretion Min : 6 Maintain N-1 Security during adverse weather Last Dispatched MW: 4
10-Sep-2021 07:10	ARG1101 BRR0 Discretion Max : 0 To allow ARG_KIK_1 to be RTS and ARG_BLN_1 PSO Last Dispatched MW: 11.5
12-Sep-2021 07:28	ROX2201 ROX0 Discretion Max : 160 Adverse weather to maintain N-1 Last Dispatched MW: 200
12-Sep-2021 07:28	CYD2201 CYD0 Discretion Max : 270 Adverse weather to maintain N-1 Last Dispatched MW: 348
12-Sep-2021 07:28	MAN2201 MAN0 Discretion Max : 638 Due to adverse weather to maintain system security. Last Dispatched MW: 738
12-Sep-2021 07:29	ROX1101 ROX0 Discretion Max : 120 Adverse weather to maintain N-1 Last Dispatched MW: 120.01
12-Sep-2021 07:37	MAN2201 MAN0 Discretion Max : 500 Due to adverse weather to maintain system security. Last Dispatched MW: 638
12-Sep-2021 07:40	HWB0331 WPI0 Discretion Max : 0 Adverse weather to maintain N-1 Last Dispatched MW: 5
12-Sep-2021 07:40	BWK1101 WPI0 Discretion Max : 0 Adverse weather to maintain N-1 Last Dispatched MW: 54
12-Sep-2021 07:43	MAN2201 MAN0 Discretion Max : 560 Due to adverse weather to maintain system security. Last Dispatched MW: 638

Event Date & Time	Event Description
12-Sep-2021 07:48	CYD2201 CYD0 Discretion Max : 270 Due to adverse weather to maintain system security. Last Dispatched MW: 270
12-Sep-2021 07:49	ROX1101 ROX0 Discretion Max : 120 Due to adverse weather to maintain system security. Last Dispatched MW: 120
12-Sep-2021 07:49	ROX2201 ROX0 Discretion Max : 160 Due to adverse weather to maintain system security. Last Dispatched MW: 160
12-Sep-2021 14:14	HLY2201 HLY5 Discretion Min : 190 Claimed rule 13.82A Discussed with SC & U5 is required for morning peak. Last Dispatched MW: 129.08
12-Sep-2021 16:07	HLY2201 HLY5 Discretion Min : 190 trader called to claim Rule 13.82 for HLY5. Discretioned on to their minimum for security purposes. Last Dispatched MW: 161.75
12-Sep-2021 18:01	HLY2201 HLY5 Discretion Min : 190 Genesis trader called to claim Rule 13.82 for HLY5. Discretioned on to their minimum for security purposes Last Dispatched MW: 200
14-Sep-2021 20:06	WHI2201 WHI0 Discretion Min : 10 Test Dispatch to check least cost solution Last Dispatched MW: 2.18
14-Sep-2021 20:07	WHI2201 WHI0 Discretion Max : 0 Test Dispatch to check least cost solution Last Dispatched MW: 2.18
14-Sep-2021 20:12	WHI2201 WHI0 Discretion Max : 0 Test 2 Dispatch to check least cost solution Last Dispatched MW: 2.18
14-Sep-2021 20:12	WHI2201 WHI0 Discretion Min : 10 Test 2 Dispatch to check least cost solution Last Dispatched MW: 2.18
14-Sep-2021 20:14	WHI2201 WHI0 Discretion Min : 10 Discretion to keep constrained on, based on overall cost. until end of TP. Last Dispatched MW: 2.18
20-Sep-2021 14:46	HLY2201 HLY5 Discretion Min : 200 Rule 13.82(A) claimed by HLY Trader to a minimum of 200MW energy. Required for AMPK. Last Dispatched MW: 195.82
24-Sep-2021 14:33	HLY2201 HLY5 ENR Min : 190 Claimed Part 13, Subpart 2, clause 13.8(a) Last Dispatched MW: 151.82
24-Sep-2021 17:49	HLY2201 HLY5 Discretion Min : 192 13.82a Brought on for security reasons. Minimum dispatch 192 Last Dispatched MW: 152.35
25-Sep-2021 1:39	HLY2201 HLY5 Discretion Min : 200 HLY operator claimed 13.82A for HLY5. Discretion applied to 200MW which is their safe operating level. Last Dispatched MW: 152.31

Appendix B: Dispatch Accuracy Dashboards

Energy

Same quarter in 2020/21

This quarter 2021/22

Measure	Description	Unit	July	August	September	October	November	December	2021 January	February	March	April	May	June	July	August	September
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	791	416	599	540	515	493	481	557	360	350	347	652	895	472	509
	Instances where the system operator has applied discretion under 13.70 of the Code to meet dispatch objective		3	-	4	10	3	-	-	3	3	-	1	15	9	12	32
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	7.01	7.06	7.11	7.06	6.89	7.11	6.88	6.64	6.88	6.73	7.14	6.89	7.08	7.11	6.98
		SI	6.51	6.53	6.83	6.62	6.74	6.50	6.35	6.48	6.45	6.59	6.65	6.58	6.64	6.53	6.71
Time error (s)	Average absolute daily time error (s) indicates imbalance between generation and load, a reflection of imperfect dispatch	NI	0.2368	0.2018	0.2064	0.1815	0.2092	0.1777	0.1953	0.2447	0.2019	0.2003	0.2113	0.2148	0.2379	0.2408	0.2317
		SI	0.2507	0.1979	0.1973	0.1818	0.1947	0.1872	0.2266	0.2506	0.2051	0.1898	0.2213	0.2072	0.2490	0.2332	0.2087
Frequency excursions	Number of frequency excursions (>0.5Hz from 50Hz)		1	1	-	6	3	-	5	3	2	-	2	3	3	1	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	3.1%	3.7%	3.5%	2.8%	2.66%	2.87%	2.39%	2.88%	2.15%	2.94%	3.59%	2.76%	3.28%	3.01%	2.66%
		SI	4.0%	4.6%	4.8%	3.9%	3.85%	4.16%	3.43%	3.78%	3.13%	3.87%	5.75%	2.78%	3.31%	2.92%	2.66%
FK outside of band limit	% of time frequency keepers spend outside their regulation limits	NI	0.11%	0.02%	0.02%	0.01%	0.15%	0.01%	0.01%	0.05%	0.02%	0.02%	0.09%	0.01%	0.01%	0.02%	0.04%
		SI	0.00%	0.01%	0.00%	0.00%	0.18%	0.00%	0.00%	0.03%	0.00%	0.00%	0.14%	0.00%	0.00%	0.02%	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.		14.65%	9.83%	9.72%	8.19%	8.50%	7.42%	9.00%	10.29%	11.97%	10.19%	10.60%	13.79%	15.05%	11.78%	10.93%
Constrained on energy- Total	Total Monthly Generation	MWh	4,006,808	3,861,813	3,671,507	3,642,908	3,396,766	3,429,779	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
	Total constrained on - All sources	MWh	23,649	26,426	24,579	24,672	23,347	18,499	24,386	13,538	10,561	24,629	23,878	23,017	25,760	25,586	33,595
		% of all generation	0.59%	0.68%	0.67%	0.68%	0.69%	0.54%	0.73%	0.43%	0.32%	0.73%	0.64%	0.62%	0.64%	0.66%	0.93%
Constrained on energy ($) - Frequency keeping	Total constrained on $ due to frequency keeping (within band is attributable to SO)	$ Constrained On Energy	712,042	379,543	503,196	399,820	292,501	455,009	325,530	426,305	407,568	574,408	849,250	529,563	678,100	418,027	387,985
		$ Grid Constrained On Energy	69,715	31,973	57,712	40,822	28,503	27,411	49,807	43,198	35,972	108,176	126,538	123,621	90,143	61,541	50,707
Optimal Dispatch (%)	Compares the average impact of a perfect foresight case against dispatch solutions. Indicates impact of wind offer, load forecast and	%	93.190%	94.380%	94.340%	94.270%	93.980%	92.800%	93.310%	93.450%	93.440%	94.790%	95.500%	95.310%	94.240%	93.790%	92.500%
Dispatch load accuracy error (%)	Average absolute difference between forecast generation (load plus losses, including PSD) and actual generation relative to the average actual generation	%	99.590%	99.620%	99.620%	99.620%	99.600%	99.610%	99.570%	99.570%	99.580%	99.610%	99.590%	99.550%	99.580%	99.620%	99.580%
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	%	97.300%	97.400%	97.780%	97.750%	97.370%	97.530%	97.610%	97.310%	96.900%	97.340%	97.600%	97.250%	97.360%	97.540%	97.730%
	Metric calculation rows	FK outside band	3	3	3	3	1	3	3	3	3	3	2	3	3	3	3
		Constrained on energy - Total	3	3	3	3	3	3	3	3	3	3	3	3	3	3	1
		Optimal Dispatch (%)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Dispatch accuracy %	Metric out of 3 (3 is best possible result)		3.0	3.0	3.0	3.0	2.3	3.0	3.0	3.0	3.0	3.0	2.7	3.0	3.0	3.0	2.3

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.

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

[7]

Metric[8]

The measures that contribute towards the metric are:

- FK outside of band limit [9]
- 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: [10]

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**

[7] 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
[8] This metric is for analysis purposes and is not part of the performance metrics report to the Authority
[9] 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
[10] 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

			September	October	November	December	2021 January	February	March	April	May	June	July	August	September
FIR procured vs Risk	NI+SI Fast Instantanous Reserve (FIR) procured divided by the estimate of FIR risk. A greater proportion suggests over procurement of reserves in the relevant island. Monthly average per trading period.	ACCE	0.73	0.80	0.71	0.67	0.78	0.82	0.78	0.70	0.80	0.78	0.70	0.71	0.67
		DCCE	NIL	NIL	NIL	0.91	1.04	1.13	0.77	NIL	NIL	NIL	0.95	0.94	0.92
FIR procured (MW)	Average FIR MW procured per trading period		243	274	208	180	239	255	224	180	222	286	251	257	203
SIR procured (MW)	Average SIR MW procured per trading period		346	359	308	285	320	339	300	266	314	381	372	386	313
FIR procured ($)	Total monthly cost ($) of FIR procured		854,060	1,591,883	880,450	691,712	946,569	1,649,525	923,443	284,960	800,816	2,029,096	1,803,527	3,083,309	1,224,614
SIR procured ($)	Total monthly cost ($) of SIR procured		579,135	465,370	298,318	229,839	222,854	399,630	138,594	102,967	278,623	1,264,344	2,216,743	2,198,285	1,038,035
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	106	90	102	110	87	88	86	92	96	101	124	115	115
		DC	NIL	NIL	NIL	89	60	62	79	NIL	NIL	NIL	77	95	88
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).		39%	37%	42%	51%	44%	41%	52%	61%	45%	35%	36%	26%	37%
IL vs Spinning Reserve	Percentage of IR procured as interuptable load.	FIR	43%	35%	40%	38%	35%	34%	29%	29%	28%	40%	39%	33%	34%
		SIR	42%	33%	37%	35%	34%	37%	28%	30%	28%	41%	38%	36%	37%
Risk setter	Most common risk setter (highest number of trading periods)	NI	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY1CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE
		SI	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	OtherIslandCE	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	100.00%	100.00%	100.00%	96.77%	99.80%	98.29%	99.66%	99.93%	100.00%	100.00%	99.80%	78.23%	95.13%
		DCCE	0.00%	0.00%	0.00%	0.81%	0.20%	1.64%	0.34%	0.00%	0.00%	0.00%	0.20%	21.91%	2.50%
		DCECE	0.00%	0.00%	0.00%	2.42%	0.00%	0.07%	0.00%	2.36%	0.00%	0.00%	0.00%	0.13%	2.36%
Average MW risk when risk setter	Average risk MW for each risk type when they are the FIR risk setter	ACCE	334	344	293	270	306	308	287	464	365	366	356	344	304
		DCCE	0	0	0	426	288	346	477	0	0	0	363	364	337
		DCECE	0	0	0	55	0	129	0	230	0	0	0	159	50

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[11] 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.

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