Credible Event Review – Scope 2024

December 2023

Keeping the energy flowing

TRANSPOWER

Version	Date	Change
1	14/12/2023	Initial Report
2		

IMPORTANT

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1 EXECUTIVE SUMMARY

Transpower, in its role as System Operator (SO), is required to identify and review the events deemed credible on the transmission system to determine if they remain valid credible events. All credible events are assessed considering committed transmission and generation changes[1].

The credible event review allows us to ensure:

- event classifications are fit-for-purpose in the present environment;
- mitigation measures are efficient and cost effective;
- we provide an opportunity for industry to be consulted.

The purpose of this document is to inform industry of the outcomes of the Credible Event Review (CER) scoping exercise undertaken by the SO. It sets the scope for the 2024 CER and our approach for this review.

To establish the scope, we have reviewed fault statistics and environmental factors impacting event classification to decide which event classifications are to remain unchanged and which will be further assessed, with an engineering and economic assessment.

During the 2024 CER, we will break the review into work packages, which the industry will be invited to comment on as they are completed.

[1] More information on event categorisation and previous reviews is available on the Transpower *website*.

2 Credible Event Review Scope 2024

This scope review has identified the following future work packages to be completed prior to December 2024.

1. Review of the System Operator Policy Statement provisions regarding classification and mitigation of stability risks to ensure that the System Operator can manage stability with the changing power system and the shift towards a more renewable generation mix and an increase in Invertor-Based Resources.
2. Review classification of the HVDC Single Pole risk accounting for committed commissioning of new technologies and grid upgrades as well as changes introduced by real time pricing. This was raised during consultation from participants during the previous CER period. This is triggered by the need to review HVDC asset resiliency, and the risk under the present economic and market settings. There are several factors raised in the environmental scan which would feed into this review.
3. Develop a policy and identify any necessary tool changes that might be required to enable Fault Ride Through (FRT) non-compliance to be consistently classified and managed under the CER methodology.
4. Review of CER definitions and mitigations applied to Interconnecting Transformers (ICTs) with the aim of defining a simpler and more consistent approach and enhancing real-time monitoring of risks.
5. Review of 2018 National Market for Instantaneous Reserves Refinements work regarding the classification of risks during the HVDC cable discharge time.
6. Engage with Transpower in its role as Grid Owner to investigate the root cause behind the increase in 110kV busbar fault statistics and identify the need for further review or other mitigation strategies.
7. In the 2022 System Security Forecast we identified the need to analyse the event categorisations of the new Bombay interconnecting transformers, as well as ensure the mitigations currently in place for the Hamilton and Islington interconnecting transformers remain appropriate. Updates have been included in Appendix 1:.

3 APPROACH TO CREDIBLE EVENT REVIEW

Approach for 2024 Review

Transpower, as SO, will use a staged approach, consulting with industry and publishing assessments for different asset classes throughout the review period.

Assessment of Event Classification

Each event classification identified as requiring further assessment will undergo:

- A power system analysis of the event under normal and planned outage conditions to determine possible issues arising from credible events.
- An economic assessment of the mitigation measures available to the SO should the event be managed as a Contingent Event (CE), Extended Contingent Event (ECE) or not actively managed as an 'Other' event.

Classification of each event is then made based on these assessments.

4 EXISTING EVENT CLASSIFICATIONS

A summary of existing credible events and their existing classification is outlined in Table 1 below.

Table 1 Existing Classification

	Identified Event (Unplanned Loss of)	**Existing Classification**
1.	Single Transmission Circuit	Contingent Event
2.	Generating Unit	Contingent Event
3.	Single HVDC pole	Contingent Event
4.	Reactive injection and reactive equipment	Contingent Event
5.	HVDC Bipole link	Extended Contingent Event
6.	Interconnecting Transformer	Classified individually as either Contingent Event, Extended Contingent Event or Other[2]
8.	Both transmission circuits of a double circuit line[3]	Other
9.	Multiple transmission circuits	Other
10.	Multiple generating units	Other
11.	Busbar connected to core grid	Manapouri as Extended Contingent Event under N-1 for frequency only However, 'Other' during N-1-1 conditions. All other buses are classified as 'Other' for N-1 and N-1-1 conditions

An environmental scan to determine if changes in policy, assets or operational environment including management of significant events, will have an impact on the overall asset classification and methodology is discussed in section 0.

Fault statistics for each asset class are then analysed to determine whether there has been sufficient change to warrant a full review of the asset class. This is discussed in section 7.

[2] Interconnector classifications included in Appendix 1:Interconnecting Transformer ClassificationsInterconnecting Transformer Classifications

[3] The Policy Statement, clause 12.4 - The loss of both transmission circuits of a double circuit line can be managed as a contingent event where the system operator has determined there is a high likelihood of occurrence based on historical information or the system operator has been advised there is a high likelihood of occurrence due to a temporary change to environmental or system conditions.

5 Outcomes of the Scope Review

This scope review document details past fault statistics with a decision on whether to progress further assessment (Section 0) and an environmental scan (Section 7.)

Table 2 Assessment Decision

	Identified Event (Unplanned Loss of)	**Existing Classification**	**Assessment Decision**	**Annualised Probability (2012-2016)**	**Annualised Probability (2016-2022)**
1.	Single Transmission Circuit	Contingent Event	No further assessment, based on fault statistics	0.70	0.69
2.	Generating Unit	Contingent Event	No further assessment, based on fault statistics	0.78	0.60
3.	Single HVDC pole	Contingent Event	A detailed assessment will be completed prior to Dec 2024. Based on feedback from the industry in the previous CER period.	1.18	1.29
4.	Reactive injection and reactive equipment	Contingent Event	No further assessment, based on fault statistics	0.36	0.27
5.	HVDC bipole link	Extended Contingent Event	No further assessment, refer to HVDC bipole classification	N/A	N/A
6.	Interconnecting Transformers	Extended Contingent Event	Updated on an ongoing basis per asset based on commissioning, decommissioning or changes in the power system.	0.05	0.08
8.	Both transmission circuits of a double circuit line	Other	No further assessment, based on fault statistics	0.01	0.02
9.	Multiple transmission circuits	Other	No further assessment. The worst case is multiple circuits at a single station. This is indirectly covered by the busbar classification (completed) and busbar frequency impact study.	0.02	0.04

	Identified Event (Unplanned Loss of)	Existing Classification	Assessment Decision	Annualised Probability (2012-2016)	Annualised Probability (2016-2022)
10.	Multiple generating units	Other	The worst case is multiple units at a single station. This is indirectly covered by the busbar classification (completed) and busbar frequency impact study. Fault statistics are decreasing which supports the classification as 'Other'.	0.08	0.02
11.	Busbar connected to core grid	Other	Assessment and reclassification completed in June 2017. Stats not changed significantly. No further assessment.	0.04	0.04
12.	Busbar connected to core grid – frequency impact	Not analysed previously.	Classified in 2019 no further assessment required.	0.04	0.04

6 ENVIRONMENTAL SCAN

Environmental changes to the grid considered in this section include major changes proposed for large, connected generation and load that are an integral part in the performance of the grid. A lot of these changes will be driven by the New Zealand's commitment to be net-zero carbon by 2050. These changes were reviewed to see if they had an impact on our existing asset classification.

Specific changes or events that were considered in the environmental scan for the 2023-2024 CER review include:

- System Operator Internal Review
- Potential displacement of thermal generation
- Upper North Island (UNI) and Upper South Island (USI) overnight high voltages
- Commissioning of renewable and inverter-based energy resources
- Potential Tiwai Exit
- Grid Commissioning

6.1 SYSTEM OPERATOR INTERNAL REVIEW

As part of the Credible Event Review Scoping process the System Operator held an internal workshop to review the updated fault statistics for each asset type, discuss the environment scan and consider which credible event classifications and processes should be reviewed or considered. As a result of the workshop, the following initiatives were identified as being a priority for the System Operator to ensure the Credible Event process continues to deliver a secure power system in a reasonable, prudent, and economic manner going forward.

6.1.1 Review of the Policy Statement

Review of Provisions for Stability Events

With the changing power system and shift towards a more renewable and inverter-based generation mix, it is timely to review the System Operator Policy Statement provisions regarding classification and mitigation of stability risks.

The classification type 'Stability Event' was previously removed from the Policy Statement because it was poorly defined and did not define mechanisms and powers the System Operator had to mitigate a Stability Event. With a growing penetration of renewable generation and invertor-based resources it is important that the System Operator clearly defines what mitigations will be used for stability risks so that it is clear to the Authority and to market participants. The Principal Performance Obligations (PPOs) state that the System Operator must:

"dispatch assets made available in a manner that avoids cascade failure of assets resulting in a loss of electricity to consumers arising from—

(a) a frequency or voltage excursion; or

(b) a supply and demand imbalance."

Managing stability risks has a direct link to the System Operator's Principal Performance Obligations as a loss of stability brings with it a risk of cascade failure.

Define how Fault Ride Through Non-Compliance is classified

Presently when a generation Asset Owner (AO) undertakes a compliance assessment of the Fault Ride Through (FRT) of one of their assets, the SO may decide to model that generator as a secondary risk in the Reserve Management Tool (RMT) depending on the nature of any non-compliance.

RMT however does not contain a full network model, rather it contains a simplified network model and a full model of connected generation, therefore if the nature of a FRT non-compliance is due to the loss of a Transmission Asset, RMT has limited ability to model this.

The purpose of this workstream is to develop a policy and identify any necessary tool changes that might be required to enable FRT non-compliance to be consistently classified, modelled and managed under the CER methodology.

6.1.2 Review of CER Methodology applied to Interconnecting Transformers

The SO has identified an opportunity for potential efficiency gains by reviewing the methodology used to classify ICTs.

Presently when an ICT has no security implications associated with its loss it is classified as an 'Other' event. When an ICT is classified as 'Other' any security implications are no longer monitored in real-time. This means that if real-time conditions are different from our planning studies some security issues may go undetected. Additionally, recent experience has identified the need to apply different mitigation strategies at the same ICT for different operating conditions, making the classification under the existing methodology difficult to apply in real-time.

We would like to review the way that we classify ICTs and the mitigations used for each classification (Contingent Event, Extended Contingent Event and Other) to find more efficient ways of monitoring the risks associated with these assets and determining their classifications. If we could monitor the risks in real-time and take more consistent action whenever a security issue is present, this would create efficiencies in the planning process as well as in our National Coordination Center (NCC) and provide greater clarity to market participants by simplifying the process.

6.1.3 Review of NMIR refinement work on HVDC Cable Discharge

In 2018 the System Operator analysed the probabilities, risks, impacts and benefits of potentially changing the classification of Contingent Event (CE) frequency events during the HVDC cable discharge time to Extended Contingent Event (ECE) or 'Other'. This may reduce or avoid 5-minute spikes in reserve quantities and prices caused when HVDC reserve sharing is blocked during the 5-minute cable discharge time. At the time this work was widely publicised, and some refinements made, however we think there could be benefit in updating this work and reviewing the current classification of CE for events during HVDC cable discharge time. The probabilities and risks of an event occurring during this period are low and in practice the market is not able to respond to such rapid increases in reserve requirements for such a short duration, and then return to the previous dispatch 5-minutes later.

6.2 Potential Displacement of Thermal Generation

The 2022 System Security Forecast (SSF) assessed the impact of the potential displacement of thermal generation at Huntly. We considered the removal of the Huntly Rankine units; their removal increases reliance on other regional generation and HVDC north flow to meet North Island demand during peak times. As a result, the increased power flow through the central and lower North Island tightens existing transmission constraints. Without the Rankine units there are times when the winter peak forecast demand would likely exceed the voltage stability limit for a Huntly Unit 5 contingency. In this case, the upper North Island voltage stability constraint may need to be used for short durations during winter, which could potentially require load management.

Transpower in its Grid Owner role analysed the impact of the potential Huntly Rankine Unit retirement in detail during the Waikato Upper North Island Voltage Management project and has committed to the following investments to mitigate transient voltage recovery and static voltage stability issues in the Waikato and Upper North Island regions.

- One dynamic reactive device at Hamilton rated 165 MVA at nominal voltage (installed).
- One dynamic reactive device at Otahuhu rated 165 MVA at nominal voltage (committed).
- A post-fault demand management scheme in the Waikato and Upper North Island.
- Preparatory works for stage 2, including additional investigation, consultation, obtaining property rights and environmental approvals, design work and non-binding tendering for future series capacitors and installation works on the BHL-WKM 1&2 transmission line.

In both the North Island backbone and Grid Zone[4] 8 studies of the SSF, an additional sensitivity was studied that considered the impact of the closure of the Taranaki Combined Cycle (TCC, also known as SPL) plant. This plant can have an impact on voltage stability in the Wellington region as well as loading on North Island backbone circuits North of Stratford. Without the generator in service, it is likely that existing backbone constraints will bind first under high HVDC south transfers.

Displacement of thermal generation could lead to the emergence of new stability risks on the power system. Managing stability risks is a key factor for the System Operator in delivering its PPOs and avoiding cascade failure. Presently, the controls and mitigations available to the SO to manage stability risks are not well defined in the System Operator Policy Statement.

Furthermore, displacement of thermal generation in the North Island, and commissioning of renewable resources in the South Island could lead to changes in the ACCE risk size and therefore changes in the number of periods that the DCCE or DCECE risk becomes the binding risk. These changes could impact the assessment of the HVDC single pole risk undertaken as part of this review.

6.3 Upper North Island and Upper South Island Overnight High Voltages

Some transmission circuits can become very lightly loaded, particularly overnight in summer. When circuits are lightly loaded this can cause overall system voltage to rise across both the North and South Island grid backbone. As System Operator, we aim to dispatch dynamic reactive plant on the system

[4] Grid Zones are operational areas of the power system and Grid Zone 8 relates to the Wellington Region.

below its maximum operating point so that a degree of headroom is available to both regulate the network voltage and provide additional support in the event of a contingency in the region. Often local generation voltage support capability is insufficient to manage all high voltage situations alone and additional actions are taken.

High voltage issues are currently managed by switching reactive equipment in the Upper North Island and Upper South Island, and, if required, removing selected transmission circuits from service. Commissioning of the Otahuhu 220kV shunt reactor and the Hamilton +/-150Mvar statcom in the North Island, and the Islington 220kV shunt reactor in the South Island have reduced the need to remove transmission circuits to manage high voltage issues in the medium term.

The management of these high voltages is currently treated as a CE risk for the loss of a reactive device, generator or transmission circuit.

6.4 Commissioning of Renewable and Invertor Based Energy Resources

Since the previous version of the credible event review there has been an increase in renewable generation and invertor-based energy resources connected to the New Zealand power system.

The second stage of the Turitea wind farm (Turitea South, approximately 101 MW) in the Bunnythorpe region is expected to tighten existing thermal constraints regarding flows into and out of the Wellington region, but generation in the Lower North Island can help maintain HVDC south transfer levels.

In the Hawke's Bay region (Grid Zone 5), new wind and geothermal generation will be commissioned in 2024. This includes Harapaki wind farm and Tauhara B geothermal station, which will add approximately 344 MW of renewable generation on the 220 kV network between Redclyffe and Wairakei. This is not expected to cause any immediate issues in Grid Zone 5 but could contribute to increased loadings on the Edgecumbe-Kawerau-3 220 kV circuit, especially during a planned outage of Atiamuri-Ohakuri-1 220 kV circuit.

As of May 2023, there were five new Solar PV farms (ranging from 10 MW to 30 MW in capacity) and one Battery Energy Storage System (rated at 33 MW) indicated to the System Operator as in a committed status. These were analysed in the December 2022 major update of the System Security Forecast (SSF) however did not create any new security issues on the Core Grid.

Commissioning of renewable generation and invertor-based energy resources could lead to increases in secondary risk during an HVDC fault due to varying degrees of compliance to FRT obligations and therefore increases in the RMT risk size or causing certain risks to bind more frequently.

Invertor-Based energy resources differ from conventional generation in that a farm consists of many units connected by an individual invertor and protection system. This potentially has implications for the probabilities and consequences of an asset failure, which could impact how these technologies are classified in the future. We intend to progress this in the 2025 calendar year, in the scope of the next CER review period to allow more time for historic data to accumulate and allow time to consider the potential impact on our operational tools. The present classification for all generating units is a CE event, this classification will continue to apply to the grid connection point of Invertor-Based Energy Resources such as wind, solar and BESS until a further review is completed.

In response to the changing power system the Authority has started a Future Security and Resilience programme to respond to increased electrification, renewables, Invertor based Energy Resources and DER (Distributed Energy Resources) connecting to the power system. As System Operator, we are assisting with this programme. The objective of the programme is to prepare the System Operator and the Electricity Industry Participation Code for increases in DER and renewable and invertor-based energy resources. The programme is scheduled to run over 10 years and will address challenges according to the priority order (see roadmap below).

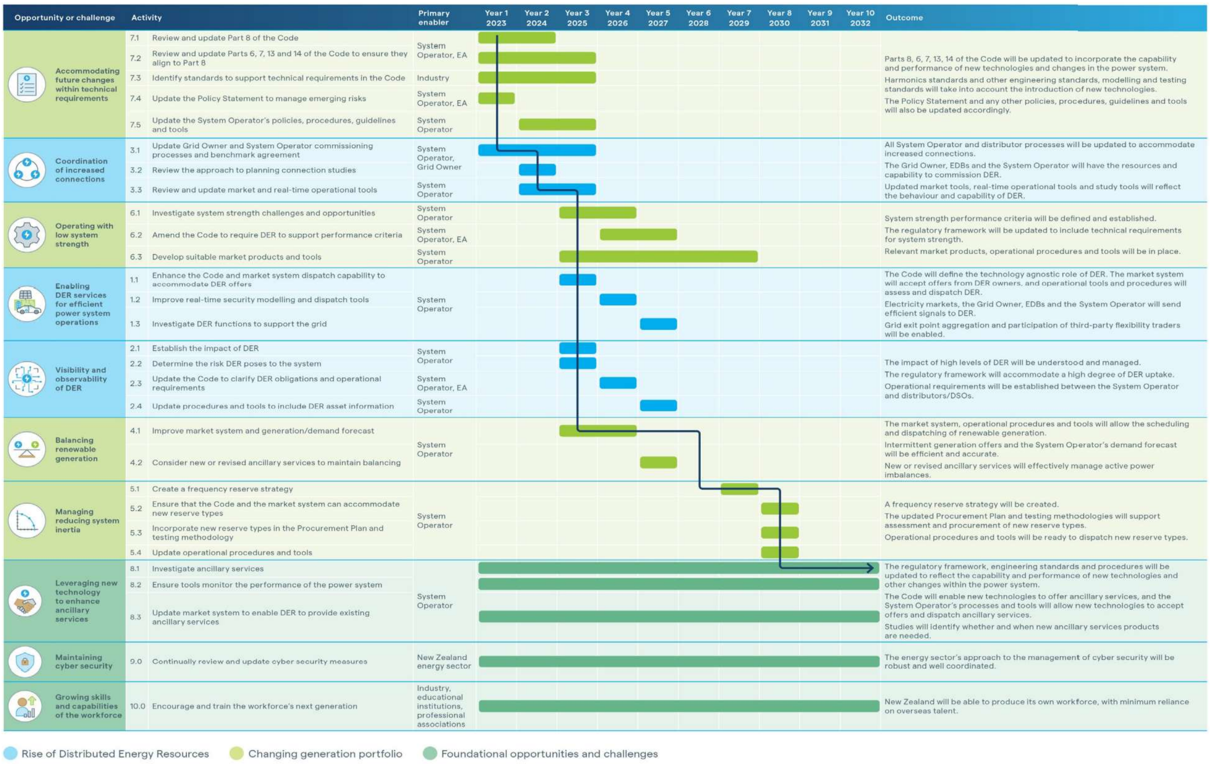


Figure 1 - Future Security and Resilience Roadmap

6.5 Potential Tiwai Exit

As a prudent System Operator, we have continued to assess operational implications associated with Tiwai's possible closure.

We identified two operational stability challenges that we will need to monitor and manage in real-time to maintain system security should Tiwai close. The issues and a summary of each are below:

1. Maintaining transient angular stability of generation at Manapouri and within the Southland region (Grid Zone 14, GZ14) should a fault occur. Transient angular stability is the ability of generators in a power system to remain synchronised following a fault or a sudden large change in generation or load. If instability occurs the consequence is likely to be voltage and frequency disturbances potentially leading to partial or total supply disruption to consumers as generation disconnects.
2. Maintaining oscillatory stability of generation within GZ14 should a fault or system disturbance occur. Oscillatory stability is also a form of rotor angle stability and is the ability of generators in a power system to maintain synchronism without exhibiting any undamped oscillation. Unlike transient angular stability, no large trigger event is required for the instability to be exhibited, the oscillations can be excited just by normal operation of the power system. If oscillatory

instability occurs, the consequence is again likely to be system wide voltage and frequency disturbances potentially leading to partial or total supply disruption as generation disconnects.

Managing stability risks is a key factor for the System Operator in delivering its PPOs and avoiding cascade failure. Presently, stability risks are not defined in the System Operator Policy statement. It is recommended that the credible event definitions for stability risks and the mechanisms the System Operator may use to mitigate them are reviewed to ensure adequate measures are in place so that we can manage stability in the future.

6.6 Grid Commissioning

In the 2022 System Security Forecast we identified the need to analyse the event categorisations of the new Bombay interconnecting transformers, as well as ensure the mitigations currently in place for the Hamilton and Islington interconnecting transformers remain appropriate. These reviews have been completed and classification updates have been added to Appendix 1:.

7 FAULT STATISTICS

The fault statistics for each asset class have been reviewed against recent data and compared to the statistics from the 2014-2019 CER to outline a starting point for the scope of the 2023 – 2024 CER. If there are no significant changes in fault statistics or environmental factors from 2016 to 2023, then the previous classification will remain.

7.1 BUSBAR SECTIONS

A technical and economic review of thermal and static voltage issues for 220 kV, 110 kV and 66 kV busbar sections connected to core grid was completed in June 2017. It recommended that these should be classified as 'Other'. While busbar events have a high impact, they are also low probability events and as such it is not economical to manage them as CE or ECE. This recommendation was accepted by the Electricity Authority and following a period for industry feedback, the final report was published to the industry in July 2017.

The frequency impact of busbar events was performed in 2019. The conclusion of this review is that Manapouri should continue to be classified as an ECE risk under normal (N-1) conditions. However, during outage (N-1-1) conditions Manapouri should be classified as 'Other'. All other buses should continue to be classified as 'Other' risks under both N-1 and N-1-1 conditions.

7.1.1 220kV Busbars

The number of 220 kV busbar forced outages in each calendar year is displayed in Figure 2 - 220kV Busbar Faults 2012 - 2022.

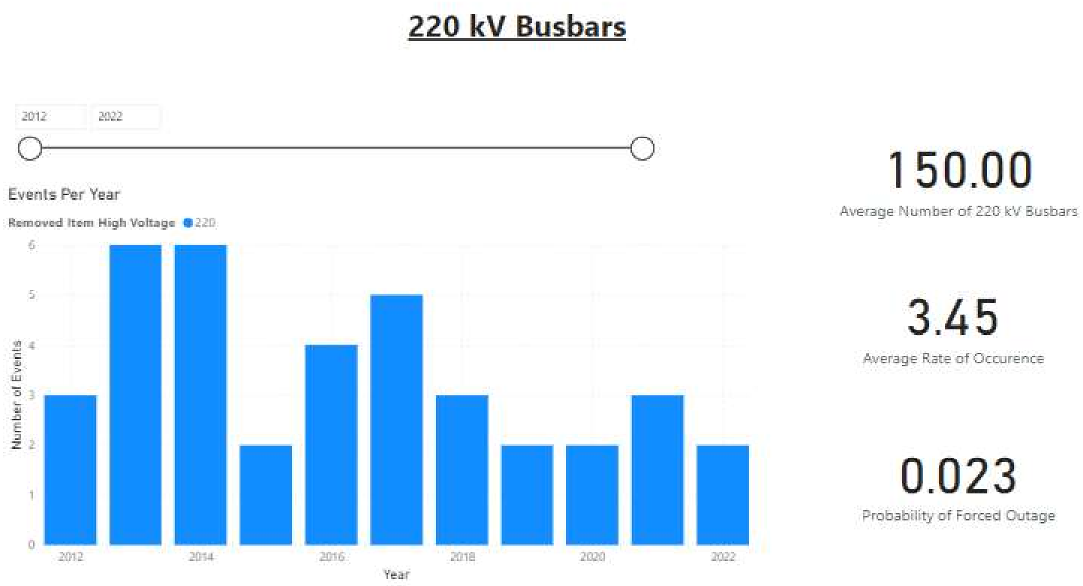


Figure 2 - 220kV Busbar Faults 2012 - 2022

The average rate of occurrence (total number divided by the number of years) has declined in recent years. The probability (average rate divided by number of elements) of Busbar outages are outlined inTable 3 220kV Busbar Statistics 2012 to 2022. The probability of a 220 kV Busbar failure has reduced from 0.028 (2012 to 2016) to 0.02 (2016 to 2022).

Table 3 220kV Busbar Statistics 2012 to 2022

Current Data			
Period (years inclusive)	**Average Rate of Occurrence**	**Average Number of Assets**	**Annualised Probability**
2012 to 2016	4.2	150	0.028
2016 to 2022	3	150	0.02

7.1.2 110kV Busbars

The number of 110 kV Busbar forced outages in each calendar year is displayed in Figure 3 - 110kV Busbar Faults 2012 to 2022

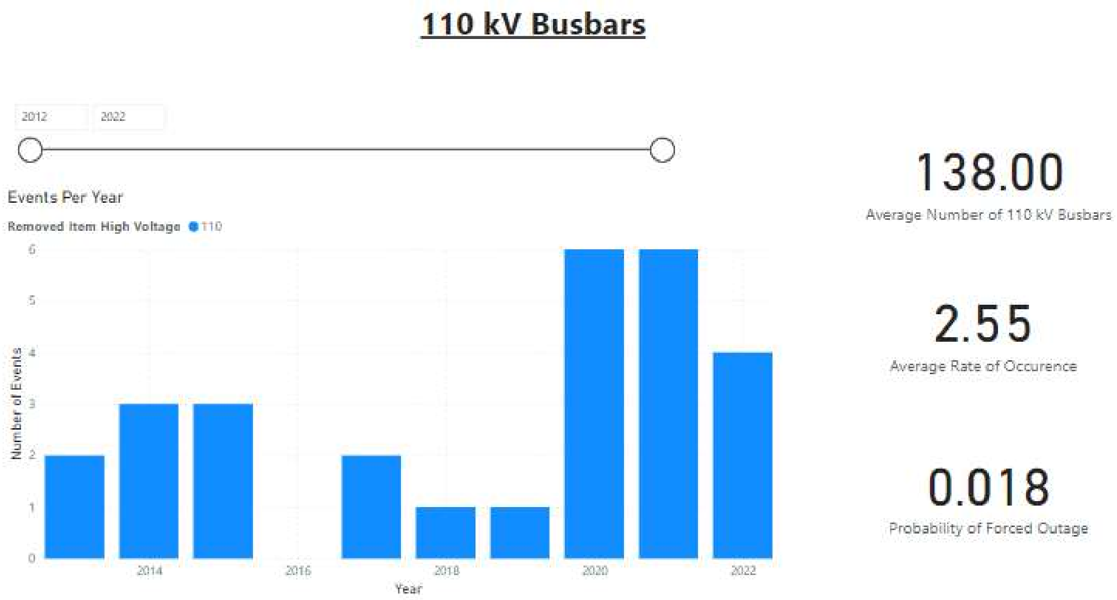


Figure 3 - 110kV Busbar Faults 2012 to 2022

The average rate of occurrence (total number divided by the number of years) has increased in recent years. The probability (average rate divided by number of elements) of Busbar outages are outlined in Table 4 - 110kV Busbar Faults 2012 to 2022. The probability of a 110 kV Busbar failure has increased from 0.012 (2012 to 2016) to 0.021(2016 to 2022).

Table 4 - 110kV Busbar Faults 2012 to 2022

Current Data			
Period (years inclusive)	**Average Rate of Occurrence**	**Average Number of Assets**	**Annualised Probability**
2012 to 2016	1.6	138	0.012
2016 to 2022	2.86	138	0.021

The 3 year average has risen to 5.33, and the 5 year average is up to 3.6 in 2022. This is a marked increase in the fault-rate for 110kV Busbar faults and warrants further investigation.

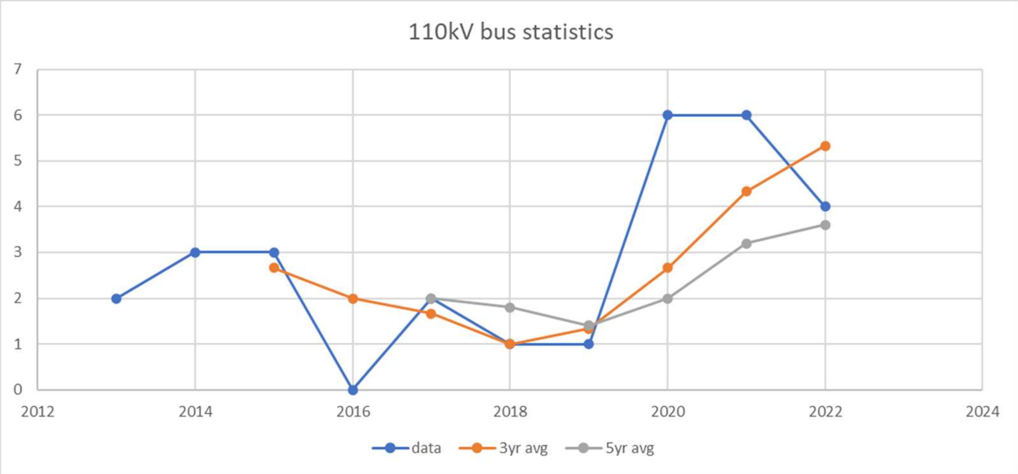


Figure 4 - 110kV Busbar Faults - Rolling Averages

7.1.3 66/50kV Busbars

The average rate of occurrence (total number divided by the number of years) has declined in recent years. The probability (average rate divided by number of elements) of busbar outages are outlined in Table 5 - 66/50kV Busbar Statistics 2012 to 2022. The probability of a 220 kV busbar failure has reduced from 0.05 (2012 to 2016) to 0.014 (2016 to 2022).

Table 5 - 66/50kV Busbar Statistics 2012 to 2022

Current Data			
Period (years inclusive)	**Average Rate of Occurrence**	**Average Number of Assets**	**Annualised Probability**
2012 to 2016	1	20	0.05
2016 to 2022	0.29	20	0.014

7.2 Interconnecting Transformers

Interconnecting Transformers (ICTs) were reviewed in 2018 and classified individually based on the probability, costs, and consequences of losing each transformer individually. The classifications are reviewed from time to time on an ongoing basis and updates published to [Event categorisation | Transpower](). The most up to date ICT classifications are included in Appendix 1:Interconnecting Transformer Classifications.

7.2.1 220 kV Interconnecting Transformers

The number of 220 kV ICT forced outages in each calendar year is displayed in the Figure 5 - 220kV Interconnecting Transformer Faults 2012 to 2022. They indicate that fault rates of 220/110 kV and 220/66 kV interconnecting transformers faults have remained steady over the last few years.

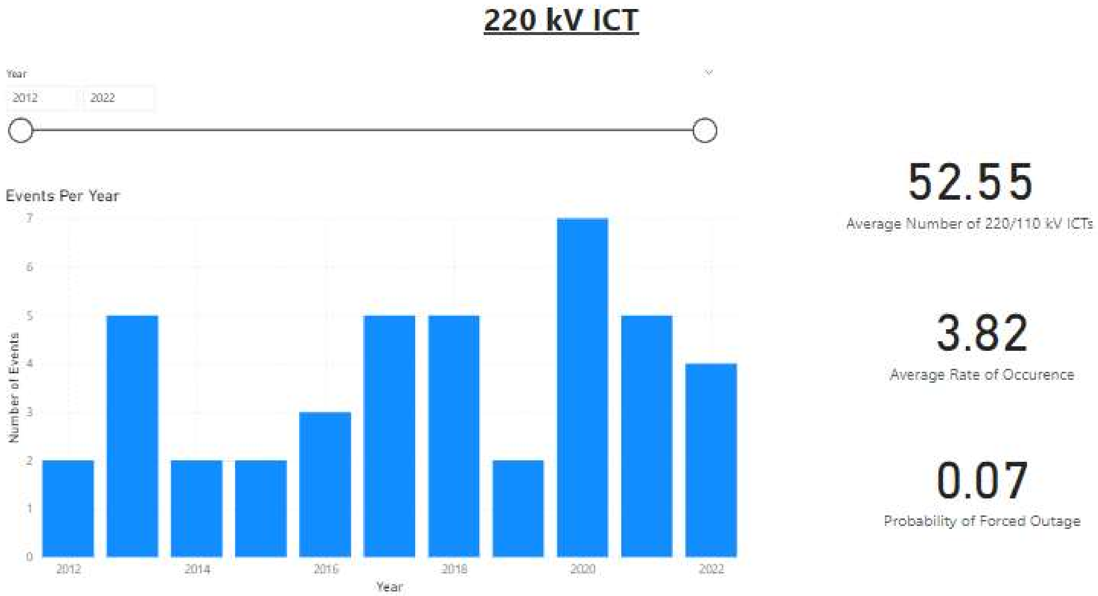


Figure 5 - 220kV Interconnecting Transformer Faults 2012 to 2022

The average rate of occurrence (total number divided by the number of years) has held steady over recent years. The probability (average rate divided by number of elements) of ICT outages are outlined in Table 6 - 220kV Interconnecting Transformer Fault Statistics 2012 to 2022. The probability of a 220 kV ICT failure has increased slightly from 0.05 (2012 to 2016) to 0.08 (2016 to 2022).

Table 6 - 220kV Interconnecting Transformer Fault Statistics 2012 to 2022

Period (years inclusive)	Average Rate of Occurrence	Average Number of Assets	Annualised Probability
2012 to 2016	2.8	53	0.05
2016 to 2022	4.43	52.29	0.08

7.3 Transmission Circuits

The loss of an AC transmission circuit is currently classified as a CE.

The number of AC (includes 220 kV, 110 kV, 66 kV and 50 kV) transmission circuit forced outages in each calendar year is indicated in Figure 6 - AC Transmission Circuit Faults 2012 to 2022.

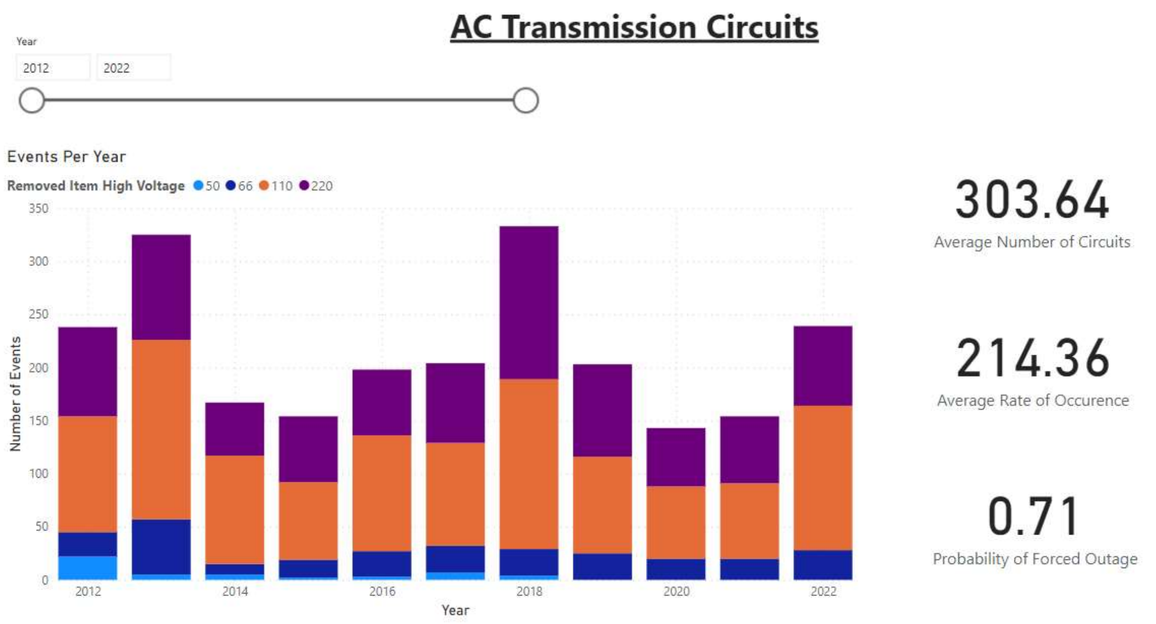


Figure 6 - AC Transmission Circuit Faults 2012 to 2022

The average rate of occurrence (total number divided by the number of years) and the probability (average rate divided by number of elements) of AC transmission circuit outages are outlined in Table 7 - AC Transmission Circuit Fault Statistics 2012 to 2022.

The probability of an AC transmission circuit outage has remained steady over the period of the analysis.

Table 7 - AC Transmission Circuit Fault Statistics 2012 to 2022

Period (years inclusive)	Average Rate of Occurrence	Average Number of Assets	Annualised Probability
2012 to 2016	224	322	0.70
2016 to 2022	219.43	320.14	0.69

7.3.1 220 kV Transmission Circuits

The number of 220 kV transmission circuit forced outages in each calendar year is indicated in Figure 6 - AC Transmission Circuit Faults 2012 to 2022.

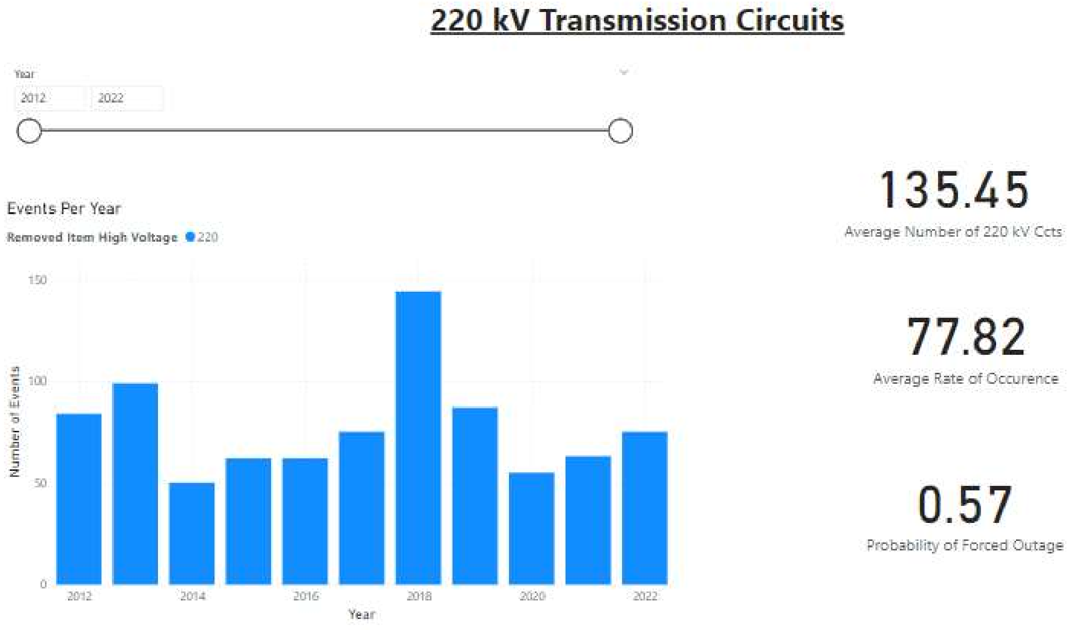


Figure 7 - 220kV Transmission Circuit Faults 2012 to 2022

The average rate of occurrence (total number divided by the number of years) and the probability (average rate divided by number of elements) of 220 kV transmission circuit outages are outlined in Table 8 - 220kV Transmission Circuit Fault Statistics.

The probability of a 220 kV transmission circuit outage has increased by approximately 6%, from 0.53 (2012 to 2016) to 0.59 (2016 to 2022). Forced outages for 220 kV circuits has remained steady over the years analysed.

Table 8 - 220kV Transmission Circuit Fault Statistics

Period (years inclusive)	Average Rate of Occurrences	Average Number of Assets	Annualised Probability
2012 to 2016	71.4	135	0.53
2016 to 2022	80.14	135.71	0.59

7.3.2 110kV Transmission Circuits

The number of 110 kV transmission circuit forced outages in each calendar year is indicated in Figure 8 - 110kV Transmission Circuit Faults 2012 to 2022.

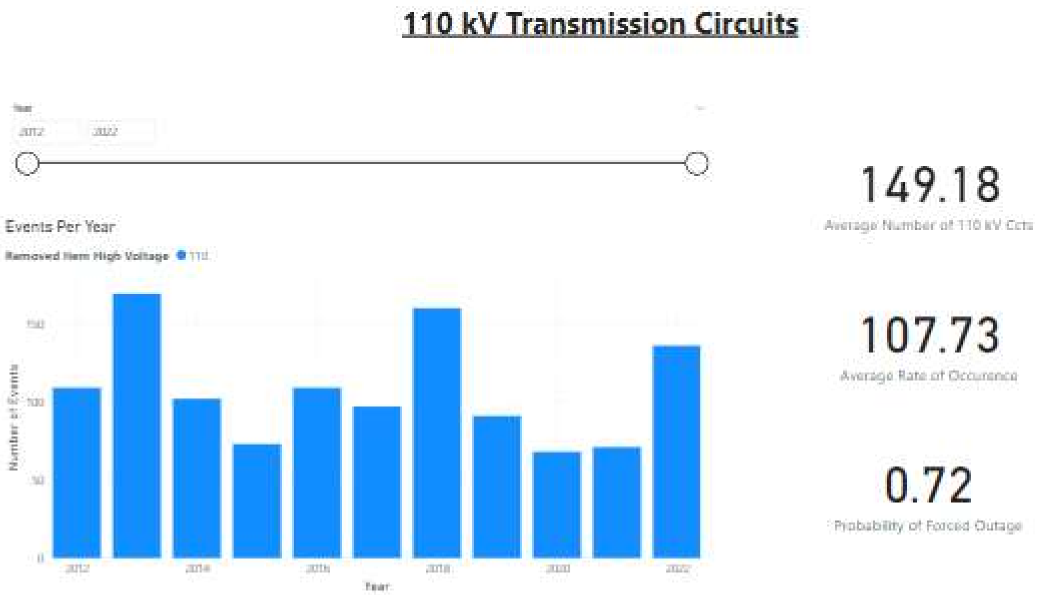


Figure 8 - 110kV Transmission Circuit Faults 2012 to 2022

The average rate of occurrence (total number divided by the number of years) and the probability (average rate divided by number of elements) of 110 kV transmission circuit outages are outlined in Table 9 - 110KV Transmission Circuit Fault Statistics 2012 to 2022.

The probability of a 110 kV transmission circuit outage has remained relatively constant over the period of the analysis reducing only 3% from 2012.

Table 9 - 110KV Transmission Circuit Fault Statistics 2012 to 2022

Period (years inclusive)	Average Rate of Occurrence	Average Number of Assets	Annualised Probability
2012 to 2016	112.4	151	0.74
2016 to 2022	104.57	148.14	0.71

7.3.3 66/50kV Transmission Circuits

The number of 66 and 50kV transmission circuit forced outages in each calendar year is indicated in Figure 9 - 66/50kV Transmission Circuit Faults 2012 to 2022.

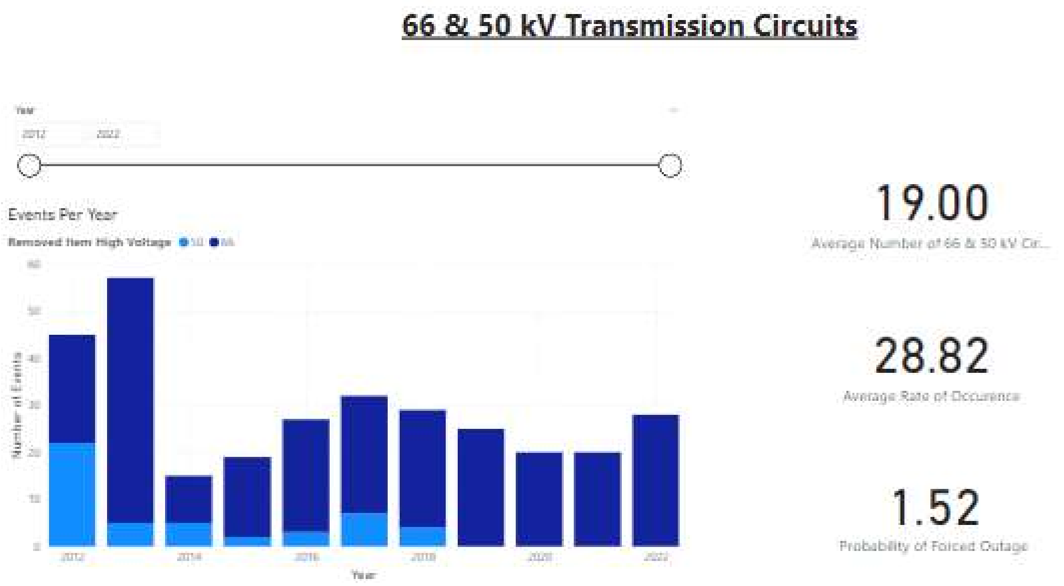


Figure 9 - 66/50kV Transmission Circuit Faults 2012 to 2022

The average rate of occurrence (total number divided by the number of years) and the probability (average rate divided by number of elements) of 66 and 50kV transmission circuit outages are outlined in Table 10 - 66/50kV Transmission Circuit Fault Statistics 2012 to 2022.

Table 10 - 66/50kV Transmission Circuit Fault Statistics 2012 to 2022

Period (years inclusive)	**Average Rate of Occurrence**	**Average Number of Assets**	**Annualised Probability**
2012 to 2016	32.6	19	1.72
2016 to 2022	25.86	19	1.36

7.4 Double Circuits Transmission Line

The loss of both transmission circuits of a double circuit line (on the same transmission tower) is normally classified as an 'Other' Event. However, the loss of both transmission circuits of a double circuit line can be classified as a CE if the SO has determined that there is a high level of likelihood of occurrence based on historical information or due to environmental or system conditions.

The number of 220 kV, 110 kV and 66 kV double circuit forced outages in each calendar year is indicated in Figure 10 - Both Transmission Circuits of a Double Circuit Line 2012 to 2022.

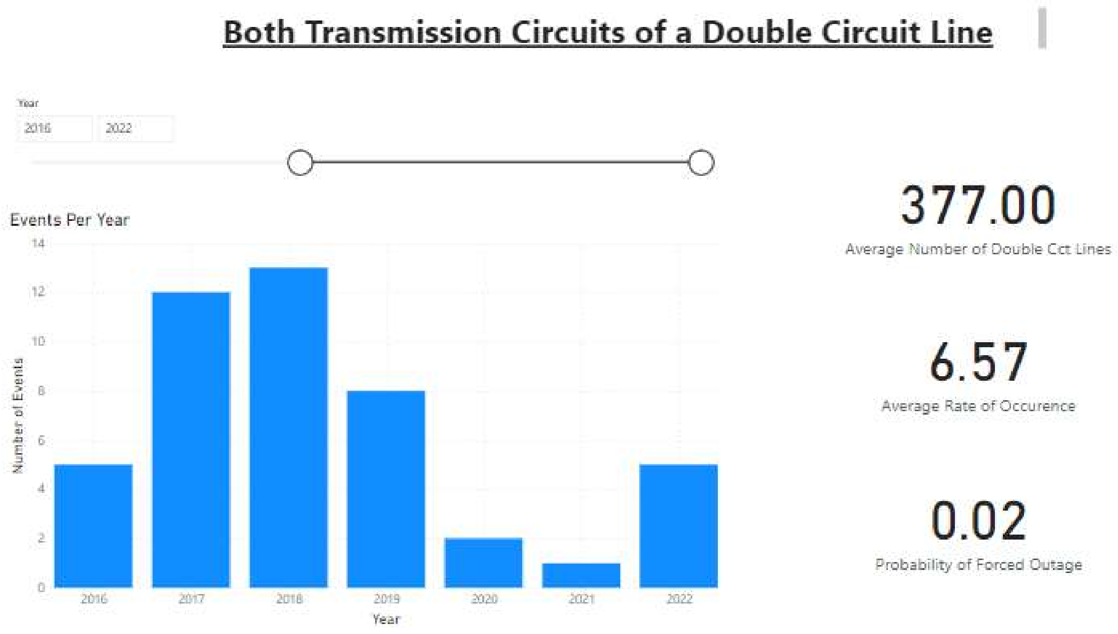


Figure 10 - Both Transmission Circuits of a Double Circuit Line 2012 to 2022

The average rate of occurrence (total number divided by the number of years) and the probability (average rate divided by number of elements) of double circuit outages are outlined in Table 11 - Both Transmission Circuits of a Double Circuit Line Fault Statistics 2012 to 2022.

Note that the average rate of occurrence of forced outages for double circuits is around 7 per year while for all circuits is around 215 per year; a difference of at least one level of magnitude. This would indicate that the current policy of managing the loss of double circuits as an Other Event is still valid in terms of risk (low) and costs (high) while the re-classification and management of double circuits as CE under adverse conditions provides a margin when the risk becomes higher.

Table 11 - Both Transmission Circuits of a Double Circuit Line Fault Statistics 2012 to 2022

Period (years inclusive)	Average Rate of Occurrence	Average Number of Assets	Annualised Probability
2012 to 2016	3.6	377	0.01
2016 to 2022	6.57	377	0.02

7.5 Reactive Devices

The loss of "reactive injections, both when provided as an ancillary service or when available from transmission assets" is currently classified as a CE.

The number of reactive devices (includes capacitors, reactors, condensers, Statcoms and SVCs) forced outages in each calendar year is indicated in Figure 11 - Reactive Device Faults 2012 to 2022.

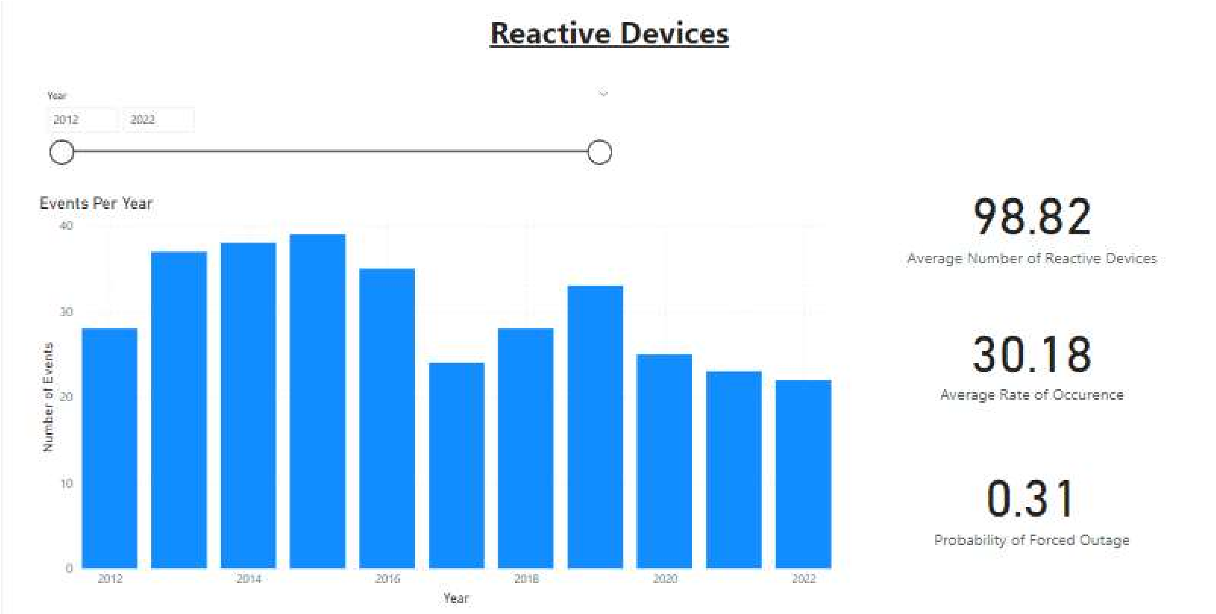


Figure 11 - Reactive Device Faults 2012 to 2022

The average rate of occurrence (total number divided by the number of years) and the probability (average rate divided by number of elements) of reactive devices outages are outlined in Table 12 - Reactive Equipment Faults 2012 to 2022.

The probability of a reactive device outage has reduced by approximately 9%, from 0.36 (2012 to 2016) to 0.27 (2016 to 2022).

Table 12 - Reactive Equipment Faults 2012 to 2022

Period (years inclusive)	Average Rate of Occurrence	Average Number of Assets	Annualised Probability
2012 to 2016	35.4	98	0.36
2016 to 2022	27.14	99	0.27

7.6 GENERATORS

The loss of a generator is currently classified as a CE.

The number of generator forced outages in each calendar year is indicated in Figure 12 - Single Generating Unit Faults 2012 to 2022. Note that wind farms and embedded generators have not been included.

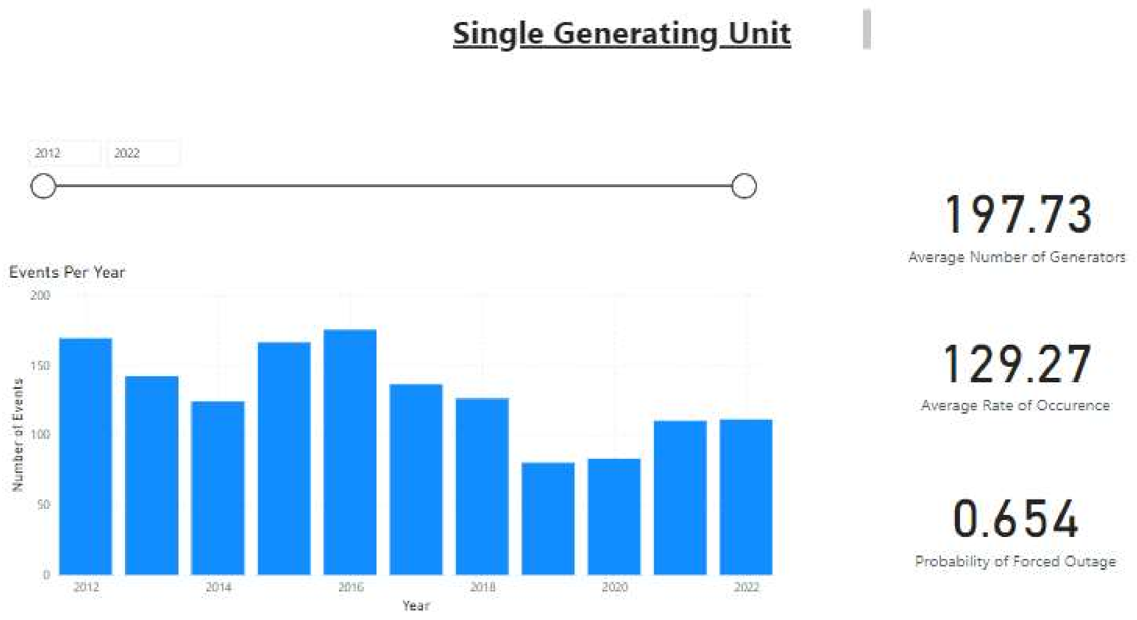


Figure 12 - Single Generating Unit Faults 2012 to 2022

The average rate of occurrences (total number divided by the number of years) and the probability (average rate divided by number of elements) of generator outages are outlined in Table 13 - Single Generator faults 2012 to 2022.

The probability of a generator outage has decreased by approximately 18%, from 0.78 (2012 to 2016) to 0.60 (2016 to 2022). Although this is a significant reduction the overall all fault rate remains still quite high with an average of 117 faults per year, meaning a classification of CE still makes sense. The fault rate is not yet low enough that we would expect it to result in a change of classification under the Credible Event methodology.

Table 13 - Single Generator faults 2012 to 2022

Period (years inclusive)	Average Rate of Occurrence	Average Number of Assets	Annualised Probability
2012 to 2016	155.2	198	0.78
2016 to 2022	117.3	197	0.60

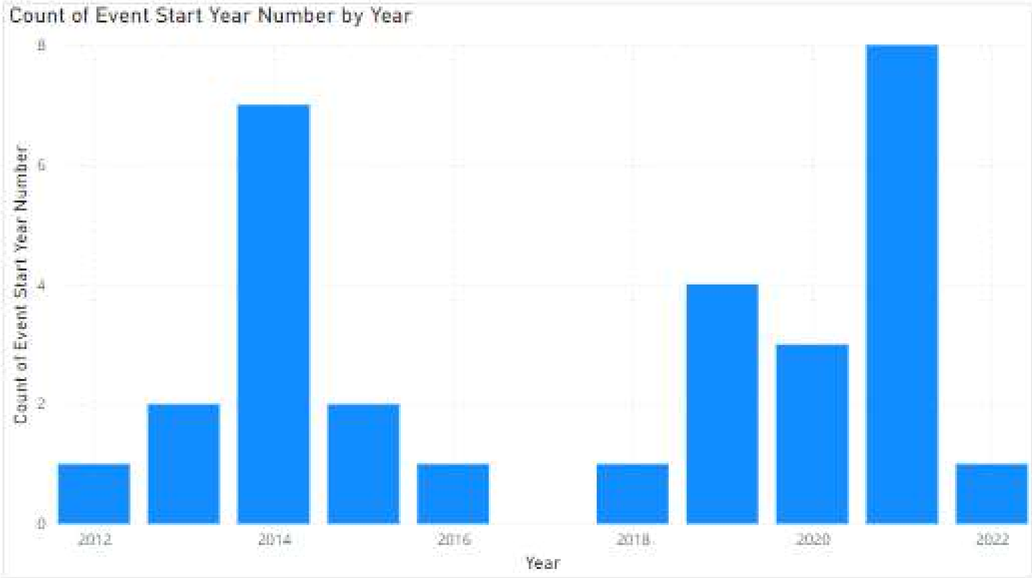
7.7 High Voltage Direct Current

7.7.1 HVDC single pole

The loss of one of the two HVDC poles is currently classified as a CE while the loss of the bipole is classified as an ECE.

The number of HVDC single pole forced outages in each calendar year is indicated in Figure 13 HVDC Pole Forced OutagesFigure 13. Note that these forced outages do not include failures due to commutation, start/stop, reduced voltage or runbacks.

Figure 13 HVDC Pole Forced Outages



The average rate of occurrence (total number divided by the number of years) and the probability (average rate divided by number of elements) of HVDC pole outages are outlined in Table 14 HVDC Pole - Probability of Forced Outages.).

Table 14 HVDC Pole - Probability of Forced Outages

Period (years inclusive)	**Average Rate of Occurrence**	**Average No. of HVDC Poles**	**Annualised Probability**
2012 to 2016	2.6	2.2	1.18
2014 to 2016	3.33	2	1.67
2016 to 2022	2.57	2	1.29

Note that while the probability appears high in comparison to other equipment, this is due to the small number of HVDC poles.

7.7.2 HVDC Bipole Classification

The loss of both poles (bipole) of the HVDC is currently classified as an ECE.

A risk is classified as an ECE if the cost of totally avoiding demand management is not justified, usually due to the probability of the event being low. In the case of the HVDC bipole, the simultaneous or near-simultaneous loss of both poles is unlikely (except in situations where AC equipment and control equipment availability create a 'single point of failure', in which case the risk classification is changed).

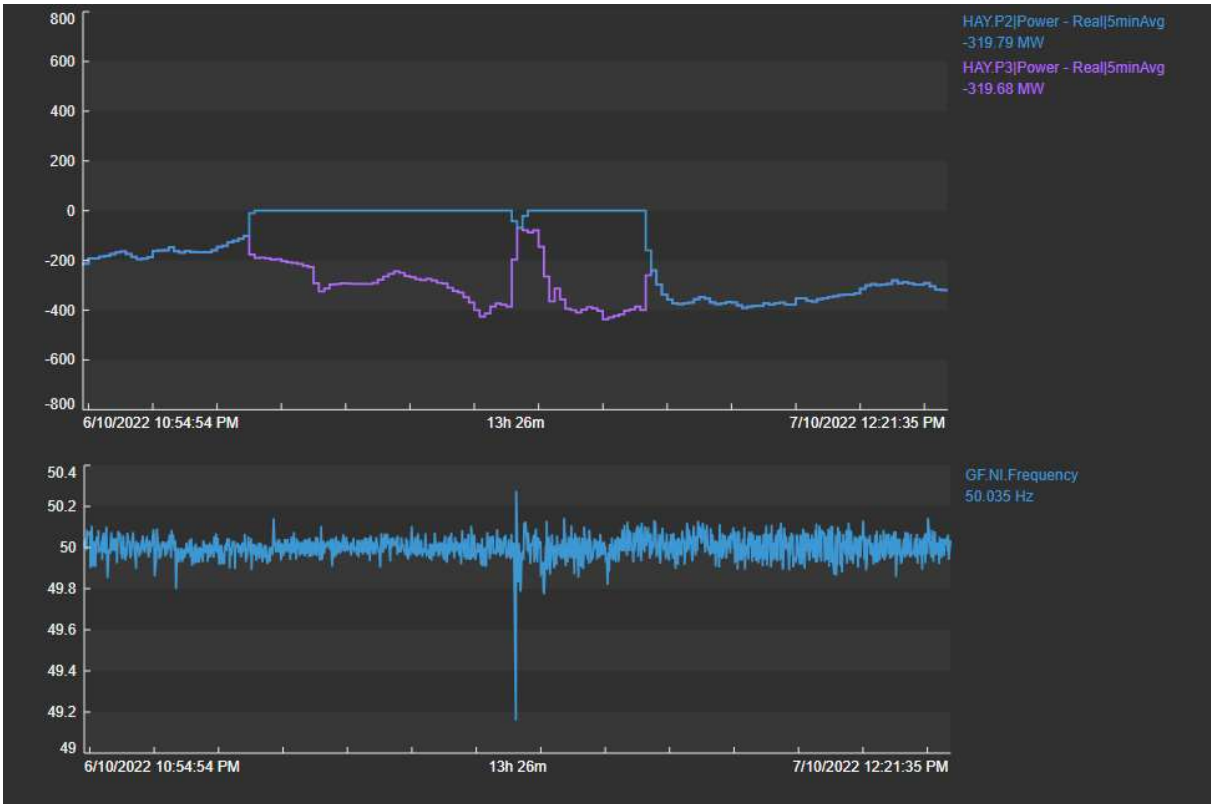
We mitigate the risk of the loss of both HVDC poles by using AUFLS or extended reserve, which is defined as the appropriate level of demand management given the likelihood of the event, currently 32% of receiving island load. AUFLS is not procured; it is a Code obligation on Connected Asset Owners (distributors and direct connects) in the North Island and the Grid Owner in the South Island to provide 32% of their load for use in automatic load-shedding during under-frequency conditions.

The effect of classifying the HVDC Bipole risk as an ECE event on the market is AUFLS effectively provides reserve cover up to a quantity of 32% of the receiving island load. At times when the Scheduling Pricing and Dispatch (SPD) solution schedules high SI generation with low NI load (or vice versa), the high resultant transfer may require instantaneous reserves to be procured to 'top up' the HVDC bipole risk cover. When this happens, the DC ECE is a binding risk. SPD co-optimisation of energy and reserves will effectively limit HVDC bipole transfer in these circumstances to the most cost-effective level.

Analysis of the binding risks from 2021 and 2022 indicates that the DC ECE binds for approximately 1.29% of the time for Fast Instantaneous Reserve and for 4.31% of the time for Sustained Instantaneous Reserve. This indicates that additional reserves required for the HVDC bipole risk occur infrequently and classification of HVDC bipole as ECE risk is efficient taking into consideration cost and impact.

Note that there are trading periods where both the DCECE and ACCE risk are binding. In this scenario, the overall volume of reserves required is set by the ACCE risk. The DCECE risk is said to also be "binding" because the total DC transfer is higher than available load allocated to AUFLS, requiring some reserves to be purchased in the receiving island. The quantity of reserves required in the receiving island is usually small. The above statistics only count trading periods where the DCECE is the only binding risk.

Fault statistics indicate that the last bipole trip with a significant frequency impact (NI frequency dropped to 47.8 Hz) was on 12 November 2013, caused by a Haywards AC fault test during commissioning of Pole 3. There were also bipole trips on 9 January 2004 and 11 December 2015, but frequency impacts were minimal.



If we were to classify the HVDC bipole risk as a CE event, sufficient sustained instantaneous reserve (SIR) would need to be procured in the receiving island to cover for total bipole transfer. The transfer limit of the HVDC bipole (1,200 MW) far exceeds the available reserve capacity in either island, and even if sufficient reserve capacity were available, the likely cost of scheduling this quantity of reserve and impact on wholesale price would be very high.

The classification of the HVDC Bipole as an ECE risk remains unchanged. This considers the availability of AUFLS and extended reserves as a mitigation and the potentially significant level of impact to frequency in both islands if an event was to occur.

Appendix 1: Interconnecting Transformer Classifications

Classifications for interconnecting transformers (ICTs) below are effective from the 1st October 2018. These were reviewed in June 2018 and have been kept up to date on an as required basis when new assets are commissioned, or existing assets are decommissioned.

Table 15 Summary of interim and new ICT classifications

Interconnecting Transformer	Recommended Classification Normal Conditions (N-1)	Recommended Classification Outage Conditions (N-1-1)	Mitigation measures
Marsden 220/110 kV T5 and T6	Other (no issues)	ECE	Split MPE-MTO. Current practice.
Albany 220/110 kV T4	Other (no issues)	Other (no issues)	-
Wairau Road 220/33 kV T7	Other (no issues)	ECE	Use 3rd supply transformer. Current practice.
Henderson 220/110 kV T1 and T5	Other (no Issues)	Other (no Issues)	-
Hobson 220/110 T12	Other (no Issues)	Other (no Issues)	-
Penrose 220/110 kV T6 and T10	Other (no Issues)	Other (no Issues)	-
Otahuhu 220/110 kV T3, T4 and T5	Other (no issues)	Other (no issues)	-
BOB 220/110 kV T4 and T5	Other (no issues	Other (no issues)	-
Hamilton 220/110 kV T6 and T9	Other (no issues)	ECE	Waikato 110 kV System on N security. Current practice.
Kaitimako 220/110 kV T2 and T4	Other (no issues)	ECE	Split KMO-TMI. TGA, MTM and KMO on N security. Changed practice.
Tarukenga 220/11 kV T2 and T3	Other (no issues)	ECE	Split OKE-TRK. TRK, ROT, LFD & KIN on N security, Changed practice.
Edgecumbe 220/110 kV T4 and T5	Other (normally open)	Other (normally open)	-
Kawerau 220/110 kV T12 and T13	Other*	Other*	No practical change to existing arrangement.
Redclyffe 220/110 kV T3 and T4	CE**	CE**	Committed SPS insufficient for reducing ICT overload below emergency rating. Current practice.
Stratford 220/110 kV T10	Other	ECE for a planned outage of one ICT, Other for any other planned outage.	System split at HWA-WVY for a planned outage of one ICT.

Interconnecting Transformer	Recommended Classification Normal Conditions (N-1)	Recommended Classification Outage Conditions (N-1-1)	Mitigation measures
Bunnythorpe 220kV T2 and T3	Other (no issues)	ECE	Transfer WPW to FHL or BPE-MTR split. Enable WGN AUVLS. Current practice.
Wilton 220/110 kV T8	Other (no issues)	ECE	Split GZ8 110 kV into 3 areas, all on N security. Only required if planned during high load periods. Otherwise splits not required.
Haywards 220/110 kV T1, T2 & T5	Other (no issues)	ECE	Split GZ8 110 kV into 3 areas, all on N security. Only required if planned during high load periods. Otherwise splits not required.
Stoke 220/110 kV T7	Other (no issues)	ECE	Split GYM-KUM. GZ9 Nelson 110 kV & 66 kV, DOB & GYM on N security. Changed practice.
Stoke 110/66 kV T3	Other (not analysed)	Other (not analysed)	-
Kikiwa 220/110 kV T1	Other (normally open)	Other (normally open)	-
Kikiwa 220/110 kV T2 (high load)	ECE***	ECE	Close KIK-T1, split KIK-STK-3, ARG-KIK, GYM-KUM. GZ9 Nelson 110 kV & 66 kV, DOB & GYM on N security. Changed practice.
Dobson 110/66 kV T11 and T12	Other (not analysed)	Other (not analysed)	-
Waipara 220/66 kV T12 and T13	Other (no Issues)	Other (no Issues)	-
Islington 220/66 kV T3, T6 and T7	Other (no issues)	ECE	Place ISL T8 In Service (normally on Hot Standby)
Bromley 220/66 kV T5 and T7	Other (not analysed)	Other (not analysed)	-
Timaru 220/110 kV T5 (existing)	ECE****	ECE	For N-1, use existing SPS. For N-1-1. split STU-TIM. TIM, TMK, TKA & OPU on N security. Current practice.
Timaru 220/110 kV T8 (existing)	ECE****	Other	Use existing SPS. Current practice.
Timaru 220/110/11 kV T5 (from Oct 2018)	Other (no issues)	ECE****	Use existing SPS.
Timaru 220/110 kV T8 &T8B (from Oct 2018)	Other (no issues)	ECE****	Use existing SPS.

Interconnecting Transformer	Recommended Classification Normal Conditions (N-1)	Recommended Classification Outage Conditions (N-1-1)	Mitigation measures
Waitaki 220/110 kV T23 and T24	ECE****	ECE	For N-1, use existing SPS. For N-1-1, co-ordination between SO and GO is critical. Current practice.
Cromwell 220/110 kV T5 and T8	Other (not analysed)	Other (not analysed)	-
Halfway Bush 220/110 kV T6	Other (no Issues)	Other (no Issues)	-
Roxburgh 220/110 kV T10	Other (no Issues)	Other (no Issues)	-
Invercargill 220/110 kV T1	Other (no Issues)	Other (no Issues)	-
Interconnecting Transformer	As of 1/10/18 Classification Normal Conditions (N-1)	As of 1/10/18 Classification Outage Conditions (N-1-1)	Mitigation measures
Marsden 220/110 kV T5 and T6	Other (no issues)	ECE	Split MPE-MTO. Current practice.
Albany 220/110 kV T4	Other (no issues)	Other (no issues)	-
Wairau Road 220/33 kV T7	Other (no issues)	ECE	Use 3rd supply transformer. Current practice.
Henderson 220/110 kV T1 and T5	Other (no Issues)	Other (no Issues)	-
Hobson 220/110 T12	Other (no Issues)	Other (no Issues)	-
Penrose 220/110 kV T6 and T10	Other (no Issues)	Other (no Issues)	-
Otahuhu 220/110 kV T2 and T4	Other (no issues)	ECE	Solid 110 kV OTA bus. Current practice.
Otahuhu 220/110 kV T3 and T5	Other (no issues)	Other (no issues)	-
Hamilton 220/110 kV T6 and T9	Other (no issues)	ECE	Waikato 110 kV System on N security. Current practice.
Kaitimako 220/110 kV T2 and T4	Other (no issues)	ECE	Split KMO-TMI. TGA, MTM and KMO on N security. Changed practice.
Tarukenga 220/11 kV T2 and T3	Other (no issues)	ECE	Split OKE-TRK. TRK, ROT, LFD & KIN on N security, Changed practice.
Edgecumbe 220/110 kV T4 and T5	Other (normally open)	Other (normally open)	-
Kawerau 220/110 kV T12 and T13	Other	Other	No practical change to existing arrangement.

Interconnecting Transformer	Recommended Classification Normal Conditions (N-1)	Recommended Classification Outage Conditions (N-1-1)	Mitigation measures
Redclyffe 220/110 kV T3 and T4	CE	CE	Committed SPS insufficient for reducing ICT overload below emergency rating. Current practice.
New Plymouth 220/110 kV T8	Other (no issues)	ECE	Split HWA-SFD or HWA-WVY. GZ6 Taranaki 110 kV on N security. Changed practice.
Stratford 220/110 kV T10	Other (no issues)	ECE	Split HWA-SFD or HWA-WVY. GZ6 Taranaki 110 kV on N security. Changed practice.
Bunnythorpe 220kV T2 and T3	Other (no issues)	ECE	Transfer WPW to FHL or BPE-MTR split. Enable WGN AUVLS. Current practice.
Wilton 220/110 kV T8	Other (no issues)	ECE	Split GZ8 110 kV into 3 areas, all on N security. Only required if planned during high load periods. Otherwise splits not required.
Haywards 220/110 kV T1, T2 & T5	Other (no issues)	ECE	Split GZ8 110 kV into 3 areas, all on N security. Only required if planned during high load periods. Otherwise splits not required.
Stoke 220/110 kV T7	Other (no issues)	ECE	Split GYM-KUM. GZ9 Nelson 110 kV & 66 kV, DOB & GYM on N security. Changed practice.
Stoke 110/66 kV T3	Other (not analysed)	Other (not analysed)	-
Kikiwa 220/110 kV T1	Other (normally open)	Other (normally open)	-
Kikiwa 220/110 kV T2 (high load)	ECE	ECE	Close KIK-T1, split KIK-STK-3, ARG-KIK, GYM-KUM. GZ9 Nelson 110 kV & 66 kV, DOB & GYM on N security. Changed practice.
Kikiwa 220/110 kV T2 (light load)	ECE	ECE	Open 220 kV circuits. Constrain on gen for reactive power support. For N-1-1, co-ordination between SO and GO is critical. Current practice.
Dobson 110/66 kV T11 and T12	Other (not analysed)	Other (not analysed)	-
Waipara 220/66 kV T12 and T13	Other (no Issues)	Other (no Issues)	
Islington 220/66 kV T3, T6 and T7	Other (no issues)	CE	-

Interconnecting Transformer	Recommended Classification Normal Conditions (N-1)	Recommended Classification Outage Conditions (N-1-1)	Mitigation measures
Bromley 220/66 kV T5 and T7	Other (not analysed)	Other (not analysed)	-
Timaru 220/110 kV T5 (existing)	ECE	ECE	-
Timaru 220/110 kV T8 (existing)	ECE	Other	For N-1, use existing SPS. For N-1-1. split STU-TIM. TIM, TMK, TKA & OPU on N security. Current practice.
Timaru 220/110/11 kV T5 (from Oct 2018)	Other (no issues)	ECE	Use existing SPS. Current practice.
Timaru 220/110 kV T8 &T8B (from Oct 2018)	Other (no issues)	ECE	Use existing SPS.
Waitaki 220/110 kV T23 and T24	ECE	ECE	Use existing SPS.
Cromwell 220/110 kV T5 and T8	Other (not analysed)	Other (not analysed)	For N-1, use existing SPS. For N-1-1, co-ordination between SO and GO is critical. Current practice.
Halfway Bush 220/110 kV T6	Other (no Issues)	Other (no Issues)	-
Roxburgh 220/110 kV T10	Other (no Issues)	Other (no Issues)	-
Invercargill 220/110 kV T1	Other (no Issues)	Other (no Issues)	-