Geomagnetically Induced Current Mitigation in New Zealand: Operational Mitigation method development with Industry input

D. H. Mac Manus[1], C. J. Rodger[1], A. Renton[2], J. Ronald[2], D. Harper[3], C. Taylor[3], M. Dalzell[2], T. Divett[4],and M. A. Clilverd[5]

[1]Department of Physics, University of Otago, Dunedin, New Zealand.
[2]Transpower New Zealand Ltd., Wellington, New Zealand.
[3]Transpower New Zealand Ltd., Hamilton, New Zealand.
[4]Victoria University of Wellington, Wellington, New Zealand.
[5]British Antarctic Survey (UKRI-NERC), Cambridge, UK.

Key Points:

- Collaboration with network power industry partners allows for the development of a more effective, realistic mitigation strategy.
- Mitigation can significantly reduce modeled GIC magnitudes and durations experienced at specific transformers of interest.
- Strategic line disconnections and installation of targeted capacitor blockers can reduce total network GIC by 32%.

Corresponding author: Daniel Mac Manus, macda381@student.otago.ac.nz

Abstract

Reducing the impact of Geomagnetically Induced Currents (GICs) on electrical power networks is an essential step to protect network assets and maintain reliable power transmission during and after storm events. In this study, multiple mitigation strategies are tested during worst-case extreme storm scenarios in order to investigate their effectiveness for the New Zealand transmission network. By working directly with our industry partners, Transpower New Zealand Ltd, a mitigation strategy in the form of targeted line disconnections has been developed. This mitigation strategy proved more effective than previous strategies at reducing GIC magnitudes and durations at transformers at most risk to GIC while still maintaining the continuous supply of power throughout New Zealand. Under this mitigation plan, the average 60-minute mean GIC decreased for 27 of the top 30 at-risk transformers, and the total network GIC was reduced by 16%. This updated mitigation has been adopted as an operational procedure in the New Zealand national control room to manage GIC. In addition, simulations show that the installation of 14 capacitor blocking devices at specific transformers reduces the total GIC sum in the network by an additional 16%. As a result of this study Transpower is considering further mitigation in the form of capacitor blockers. We strongly recommend collaborating with the relevant power network providers to develop effective mitigation strategies that reduce GIC and have a minimal impact on power distribution.

Plain Language Summary

The New Zealand electrical power network was modified in multiple ways to reduce the impact of extreme Space Weather events. By working directly with our industry partners, Transpower New Zealand Ltd, a procedure has been developed to reduce unwanted direct current (DC) at transformers while still maintaining the continuous supply of power throughout New Zealand. This has been adopted as an operational procedure in the New Zealand national control room to manage space weather events. In addition, simulations show that installing DC blocking devices at specific transformers further reduces the risk to the network.

1 Introduction

Geomagnetically Induced Currents (GICs) are electrical currents that can flow through power systems, pipelines, and other infrastructure as a result of rapid variations in the Earth's magnetic field (Bolduc, 2002). These fluctuations are caused by geomagnetic disturbances, themselves caused by solar activity phenomena such as the impact of coronal mass ejections on the Earth's magnetosphere. The changing geomagnetic fields then induce electrical currents in conductive materials on the Earth's surface, termed GIC. GICs can cause a number of problems for power systems and other infrastructure, including damage to transformers and other equipment, voltage instability, and power outages (e.g., Samuelsson (2013); Boteler (2015)). In extreme cases, GICs are expected to cause widespread blackouts and other disruptions to critical infrastructure (National Research Council, 2008; JASON, 2011; Oughton et al., 2017). The best known extreme geomagnetic disturbance is the Carrington event of September 1859 (Carrington, 1859), although other examples are May 1921 (Gibbs, 1921; Hapgood, 2019) and the "Carrington which missed" in July 2012 (Ngwira et al., 2013).

The probability of such an extreme geomagnetic disturbance occurring is an active area of current scientific research. The possibility of a worst-case event happening during a 10 year return period could be as low as 3% to as high as 12% (Cannon, 2013; Chapman et al., 2020; Riley & Love, 2017). The nature of an extreme geomagnetic disturbance is also an area of active research. One example of an extreme disturbance appropriate for mid-latitudes was provided by Hapgood et al. (2021). Mac Manus et al. (2022b) modelled GIC in the New Zealand power network during multiple extreme storm scenarios and found between 44 and 115 New Zealand transformers (13%-35%) are at risk of damage due to high magnitudes of GIC for extended durations. The locations of these transformers were not localised within a specific region of the country, such as the lower South Island where aurora is sometimes visible during geomagnetic storms, but were spread throughout the whole power network. The findings of Mac Manus et al. (2022b) indicate that any effective mitigation approach to compensate for the impact of extreme GIC needs to be applied across all regions of New Zealand, from the lower South Island to the upper North Island.

The extreme storm GIC modeled scenarios for the New Zealand electrical network form a vital input into the current study, and thus we discuss the Mac Manus et al. (2022b) work in more detail. These authors included industry representatives, in this case from the New Zealand grid operator and owner, Transpower New Zealand Ltd. The industry authors provided thresholds of GIC magnitude and time periods which were ”tolerable”, with higher magnitude/time combinations leading to either an excessive ”loss of lifetime” for a given transformer unit or a very high probability of catastrophic insulation failure. Separate thresholds were provided for single and three-phase transformer units, with the caveat that these values were for new equipment, rather than the real-world aged equipment likely to be in an operational network. As a starting point, Mac Manus et al. (2022b) took an extreme geomagnetic storm as having a peak rate of change of 4000 nT/min at the location of the Eyrewell (EYR) geomagnetic observatory, based on the mid-latitude reasonable worst case 100-year geomagnetic storm of 4000-5000 nT/min (Hapgood et al., 2021). Mac Manus et al. (2022b) then used three different experimentally observed geomagnetic disturbances (March 1989, October 2003, and September 2017) to provide the 1-1.5 day time-variations for three extreme disturbance representations. In all cases the time variation representations were scaled such that the one-minute time resolution horizontal magnetic field rate of change had a maximum value of 4000 nT/min. In order to consider changing storm intensity with latitude, three different representations were considered, two from the literature (RODGERS = Rogers et al. (2020), and NERC = NERC (2016)), and one representation with a constant magnetic field rate of change for all latitudes, referred to EYR. The combination of 3 time variations and 3 latitude variations produced 9 different extreme storm scenarios. Mac Manus et al. (2022b) then applied a transformer level GIC-calculation model which had been validated against previous GIC observations during storms (Divett et al., 2020; Mac Manus et al., 2022) to calculate the time-varying GIC for all the earthed main grid transformers in the New Zealand power network. These GIC values were then compared with the industry-provided GIC ”danger levels” to identify at risk transformers. One interesting finding of that study was the transformers identified to be at risk were largely independent of the time-variation representation, but depended more on the latitude variation scenario and included most of the major population centers in New Zealand.

The act of scaling the magnetic field time variations to represent an extreme storm comes with the assumption that the location of the auroral oval is unchanged. In reality, during an extreme storm, the auroral oval will not only be enhanced but will likely be centered more equator-ward than for the reference geomagnetic storms used in this study. Unfortunately due to available observations representing significantly smaller events, this assumption is necessary.

The results of the extreme storm scenarios discussed above were derived using a thin-sheet model. This consists of a ground conductance model with approximately 20 km diameter grid cells. The underlying structure is represented as four layers of varying resistivity and depth. The thin-sheet model induces electric fields at the surface of the Earth due to the temporal variations of the magnetic field input. The resulting GIC was scaled to account for model limitations. This spectral scaling was validated against a large dataset of GIC observations (see Mac Manus et al. (2022, 2022b) for more details).

The New Zealand high-voltage AC power network consists of a number of substations, each with a varying number of transformers. Throughout this manuscript, when discussing substation GIC, we a referring to the total GIC flowing through the earthing points on transformers at the given substation. In New Zealand this ranges from 1-10 transformers depending on the substation.

A number of mitigation techniques have been previously investigated in the literature (Kappenman, 2010; Rajput et al., 2021). A commonly discussed technique involves the installation of GIC blocking devices. These consist of a capacitor at the transformer neutral, blocking DC without affecting the flow of AC current (Kappenman et al., 1991). If poorly designed, this can cause ground fault detection systems to be compromised, reducing system stability (Molinski, 2002). Another possibility for GIC mitigation through equipment changes is using a series capacitor in the phase conductors of the transmission line (Arajarvi et al., 2011). However, essentially "passive" mitigation is also possible, by changing the network configuration through switching, without the need to install new equipment. For example. line switching or disconnecting particular transmission lines can also help to reduce the GIC at specific locations in the network. However, such switching also modifies the AC flow and if carried out incorrectly it could result in system overloads and/or voltage instability. This highlights an important factor to consider with mitigation. Any efforts should sufficiently reduce GIC and yet still provide sufficient AC flow throughout the network as required by customers. Switching could also cause large GICs to flow in adjacent lines (Erinmez et al., 2002), or increased currents in nearby transformers or substations, a phenomena here referred to as the "Whack-A-Mole effect". Clearly it is important to consider the implications of GIC mitigation practices, in terms of the ability of the "protected" network to deliver electrical power to consumers, as well as the changes in GIC levels across the network as a result of the mitigation approaches.

A valuable aspect of modelling GIC throughout the whole transmission network structure is to be able to see how GIC are distributed within the system. Mitigation might involve disconnecting certain lines and transformers, installing different equipment, or other network reconfiguration. Mitigation methods can thus be tested through modelling to investigate how network changes could impact the distribution of GIC throughout a power network during a geomagnetic storm. Such modelling can provide valuable insight into ways power industry providers could modify an existing network to reduce potential GIC related damages.

In this study we have applied a number of different mitigation strategies to the nine extreme storm scenarios discussed in Mac Manus et al. (2022b). We initially investigate a historic mitigation strategy, devised by New Zealand's high voltage electricity transmission system owner and operator, Transpower New Zealand Ltd. That strategy was solely focused on the power network in the region of the lower South Island of New Zealand (Section 3) Extending the methods of the historic strategy, we apply such mitigation to the whole New Zealand network (Section 4). Building on this, a more targeted approach involving less network changes is developed (Section 5); the targeted approach being necessary as the initial all New Zealand strategy, though physically valid, did not maintain operational stability. A more targeted approach was formulated by directly working with Transpower, ensuring network stability was maintained. This targeted mitigation strategy is now the revised operational procedure available in the national control room to manage GIC, replacing the earlier historic regional strategy. Additional mitigation involving the use of capacitors to block the flow of DC current in particular transformers is investigated (Section 6). Lastly we investigate the number of capacitor blockers required to reduce the GIC to a safe level (Section 7). This involved running the network model at a given time instance within an extreme event, installing a capacitor blocker at the transformer with the largest GIC and repeating until all transformers are blocked and the overall GIC is reduced to zero.

We believe this analysis is one of the few examples of space weather researchers working with the power industry to develop operational mitigation strategies, informed by joint research, and described in the open scientific literature.

2 GIC mitigation procedures

There are two main factors that make GIC mitigation challenging. Firstly, GIC are caused by geomagnetic storms which are triggered by changes in the solar wind, and are thus, inherently highly variable in magnitude and frequency. Secondly, very large geomagnetic storms that would necessitate GIC mitigation are rare and most networks have little to no operational experience of dealing with them.

The goal of GIC mitigation is to increase the resilience of the power system to geomagnetic storms. This can be thought of in four separate steps. The first is prevention prior to the geomagnetic event to keep the system operating and stable. Second, is the ability to manage issues that arise during the event. This could involve rapidly adapting to the evolving situation and communicating effectively to keep the most important areas of the network operating. The third component is the recovery after the event. This may involve returning the network to its normal condition as quickly as possible. Lastly, the ability to learn from the event is vital as any knowledge gained could help revise existing procedures and create new ones to improve damage prevention, management and recovery.

The content of the current study focuses on the first step, mitigation prior to the geomagnetic disturbance event. With sufficient warning the mitigation methods discussed in the following sections can be implemented prior to the geomagnetic event occurring with the goal of reducing any need for steps two and three (management during and recovery after the event). In the case of a solar wind-triggered extreme geomagnetic disturbance, early implementation of a mitigation procedure is possible through predictions of CME arrival and impact severity, along with solar wind observations near the Earth. While this is a current and active research area, operational space weather forecasting and warning already exists, allowing the electrical industry to undertake mitigation steps before the storm starts.

Throughout this manuscript we will, at times, talk about the average 60-minute mean GIC and the maximum GIC so it is important to define what these represent. For each mitigation plan, we have modelled the GIC for all nine extreme storm scenarios described by Mac Manus et al. (2022b). For each scenario, the maximum absolute GIC averaged over a 60-minute window was calculated. The mean was determined from those nine values, proving a single representative GIC value at each location across all the extreme storm scenarios. This is termed the average 60-minute mean GIC. The maximum GIC represents the single largest absolute GIC value recorded for that transformer or substation during the extreme storm scenario/scenarios described. It is also worth noting that due to the rather large GIC magnitudes we will be dealing with, all GIC values have been rounded to the nearest 10 A.

In the following sections we will discuss and show the results of three unique mitigation plans implemented on the New Zealand power transmission network. These mitigation plans are summarised in Table 1 below and will largely be referred to by their acronyms.

3 Historic Transpower Lower South Island (HTPLSI) mitigation plan

Since the early 2000s, Transpower has had a mitigation procedure detailing actions which should be undertaken by staff in the network control rooms to manage GIC (Transpower, 2015). This procedure was developed after a storm in November 2001 which caused dam-

Table 1: Three mitigation plans used throughout this manuscript.

Name	Acronyms	Description
Historic Transpower Lower South Island	HTPLSI	Original mitigation plan, focusing on line disconnections in the lower South Island
Disconnect Redundant Lines New Zealand	DRLNZ	Disconnect all occurrences of parallel lines in New Zealand
Transpower 2022 New Zealand	TP2022NZ	Targeted mitigation developed in collaboration with Transpower

age to a transformer in Dunedin (Béland & Small, 2004; Marshall et al., 2012; Mac Manus et al., 2017). The procedure is implemented if a geomagnetic event is deemed to be ”in progress”. This requires that the following two criteria be simultaneously true:

- Multiple SCADA (Supervisory Control And Data Acquisition) alarms over a wide geographical area (activate if +/-8 A of DC current is measured at a transformer) exceed activation thresholds by more than 1 A for 15 minutes continuously.
- A previously received alert or warning from the Space Weather prediction center (SWPC) of a Kp = 6 or larger event in progress or expected to occur.

or that the single condition below is true:

- A transformer temperature alarm occurs in a region where multiple SCADA alarms have been happening for longer than 5 minutes.

If the required criteria are met and other potential reasons for the DC alarms have been eliminated, a GIC event is considered ”in progress” and a ”grid emergency” is declared allowing for grid reconfiguration through the ”Historic Transpower Lower South Island” (HTPLSI) mitigation plan to decrease GIC magnitude. This strategy involves disconnecting the equipment in Table 2 with locations shown in Figure 1.

Table 2: Equipment disconnections for the HTPLSI mitigation plan.

Substation 1	Substation 2	Abbreviation	Line Voltage (kV)	Circuit
Manapouri	North Makarewa	MAN-NMA	220	1, 2, or 3
Roxburgh	Three Mile Hill	ROX-TMH	220	1, or 2
North Makarewa	Three Mile Hill	NMA-TMH	220	1, or 2
Benmore	Twizel	BEN-TWI	220	1 of 1
Roxburgh	-	ROX T10	-	-

The first three of these steps involves removing one of two (or three) redundant, parallel transmission lines that run between the same two locations. The removal of one of the parallel lines increases the network impedance between those locations, which will decrease GIC magnitudes entering transformers, particularly for transformers at each end of the transmission lines. There is only one circuit connecting Benmore (BEN) to Twizel (TWI). However there are other nearby routes between the two substations, one through Ohau B (OHB) and another through Ohau C (OHC). If one of the circuits is already out of service, it is not necessary to remove another; i.e., if ROX-TMH 1 is out for other reasons at the time of the grid emergency (for example due to maintenance) ROX-TMH 2 is not removed.

When Transpower developed this strategy the underlying assumption was that the impact of GIC was most pronounced in long east-west transmission lines at geographic latitudes larger than 45°. This criteria is true in the lower South Island, and the document describing the procedure indicates it was believed that large GIC flows between Manapouri (MAN) in the west and Halfway Bush (HWB), near Three Mile Hill (TMH) in the east. The locations of MAN and HWB are indicated by the magenta circles in Figure 1.

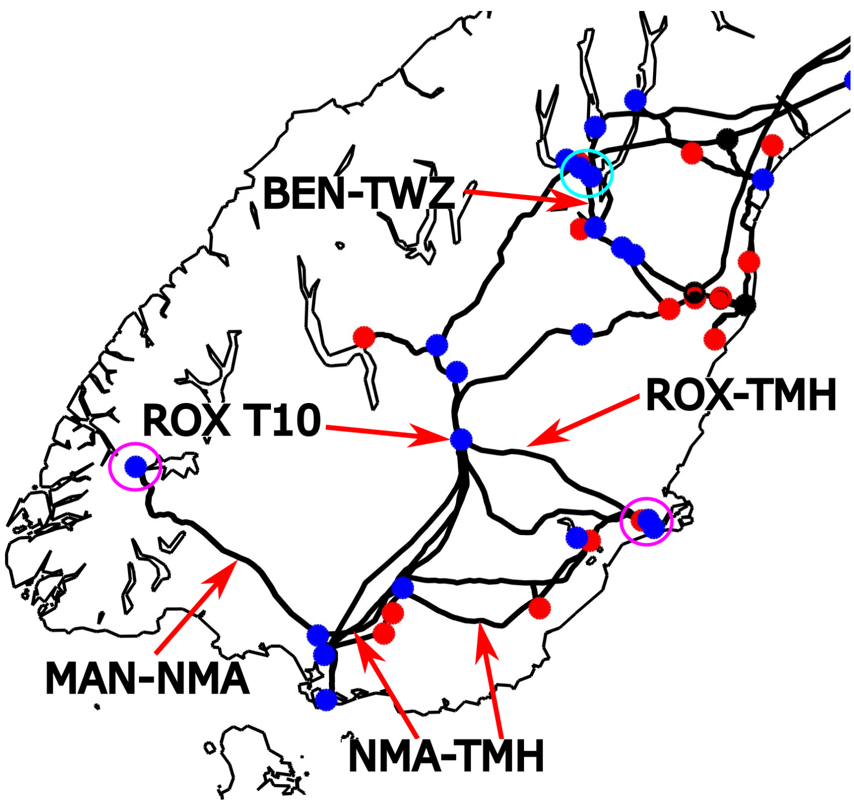

Figure 1: Map showing the implementation of the HTPLSI mitigation plan and the location of disconnected equipment. Earthed substations are represented by blue circles while unearthed substations and T-junctions are given by red and black circles, respectively. The cyan circle surrounds the Ohau B (OHB) and Ohau C (OHC) substations and the magenta circles surround the Manapouri (MAN) and Halfway Bush (HWB) substations described in the text.

In this section the impact of the HTPLSI mitigation plan is examined when applied to the nine extreme storm scenarios discussed in Mac Manus et al. (2022b). Initially we will discuss the change in substation GIC (i.e. the total GIC magnitude passing through the transformers in a given substation to earth) before looking at the GIC levels for specific transformers. Figure 2 shows the change in the substation average 60-minute mean GIC. Here, only substations with a 5% or larger GIC change due to the mitigation plan are labelled. A downwards green arrow indicates a decrease in GIC magnitude by the percent shown, while upwards red arrow indicate increase. The value in brackets corresponds to the change in absolute substation GIC for that substation. For example, the GIC at the South Dunedin (SDN) substation, decreases by 430 A (1410 to 980 A) when the HTPLSI mitigation plan is applied. This corresponds to a 30% decrease in GIC.

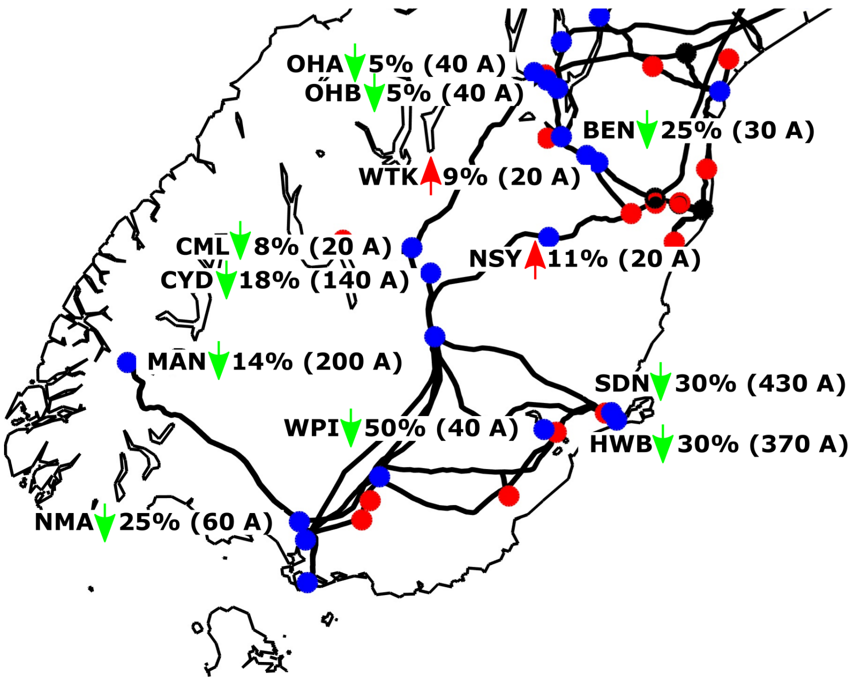

Figure 2: Change in the substation-level average 60-minute mean GIC for the HTPLSI mitigation plan. Substations with a 5% or larger GIC change are labelled. Earthed substations are represented by blue circles while unearthed substations and T-junctions are given by red and black circles, respectively. A downwards green arrow indicates a decrease by the percent shown while an upwards red arrow indicates an increase. The value in brackets corresponds to the absolute substation GIC change.

Figure 2 shows that under this mitigation strategy the vast majority of lower South Island substations experience lower GIC levels. Substations not shown in the figure have less than 5% GIC changes. The percentages given in Figure 2 are the average of the nine extreme storm scenarios. While only the average 60-minute mean GIC are shown, in practice the HTPLSI mitigation plan has approximately the same percentage change across all of the scenarios modelled, suggesting that any one scenario can be used to describe the percentage GIC changes at each substation. Similar percentage changes apply for the maximum substation GIC, as well as the mean values shown in Figure 2. This is understandable when one considers the impact of this mitigation approach on the network. By disconnecting some transmission lines, the network configuration has been modified. However the modification is exactly the same for all nine extreme storm scenarios modelled. Therefore, when we compare the GIC modelled for the original network configuration against the modified mitigation network the relative percentage change at each substation should be very similar, as the impedance changes are the same in each scenario, and Ohm's law is linear.

Ultimately it is the transformer GIC that is of interest as the primary impact to the power grid originates from transformers undergoing half-cycle saturation due to GIC. Table 3 lists the transformers whose GIC levels change by 50 Amps or more under the mitigation configuration. The values given are the average 60-minute mean GIC and maximum GIC across the nine extreme storm scenarios.

Table 3: Average Transformer GIC changes for the nine extreme storm scenarios under the HTPLSI mitigation plan. Transformers exceeding a 50 A change in the average 60-minute mean GIC are listed. The term LVR (low voltage resistor) represents the common winding of an autotransformer while HVR (high voltage resistor) represents the upper phase (series) winding of an autotransformer or the high voltage winding of normal transformers.

Transformer	60-minute mean GIC change ($\|A\|$,%)	max GIC change ($\|A\|$,%)
HVR SDN T2	-430, -30%	-1480, -30%
HVR HWB T6	-330, -52%	-1110, -52%
LVR HWB T6	-260, -27%	-880, -27%
LVR ROX T10	-220, -100%	-870, -100%
HVR HWB T3	-110, -38%	-370, -37%
HVR ROX T10	-90, -100%	-540, -100%
HVR ROX T7	70, 175%	340, 227%
HVR ROX T8	70, 175%	340, 227%
HVR ROX T6	140, 175%	690, 223%

Comparing the average 60-minute mean GIC in Figure 2 and Table 3 highlights some similarities and differences that can be found by looking at the substation and transformer GIC independently. Transformers at SDN and HWB show large decreases supporting the results of Figure 2. The transformer labelled "HVR HWB T6" is the upper phase (series) winding of the #6 transformer. GIC still flows through this winding but it does not directly contribute to the substation GIC as it is not earthed. The Manapouri (MAN) and Clyde (CYD) substations show decreases of over 100 A, however they consist of nine and six earthed transformers respectively, so the GIC is distributed amongst all of them, leading to smaller changes for individual transformers. The Roxburgh (ROX) substation does not appear in Figure 2 as the average 60-minute mean GIC only decreases by 3% (30 A). However, in Table 3 we can see significant changes in the transformer-level GIC. The ROX #10 (LVR ROX T10) transformer shows a 100% decrease in GIC including the upper phase winding (HVR ROX T10) because they have both been removed from service as part of the HTPLSI mitigation plan. Disconnecting ROX T10 along with the ROX-TMH 220 kV transmission line also reduces the GIC at the other 220 kV transformers in the same substation (i.e., ROX T1-T5) by a total of 90 A. In contrast, the transformers in this substation connected to the 110 kV network (ROX T6-T8) increase by 280 A in total. These results combine to give a small net substation GIC change of only 3%, equivalent to 30 A. If only substation-level GIC was inspected then we would not be aware of such large increases and decreases for individual transformers at Roxburgh substation.

From this we conclude that the HTPLSI mitigation plan shows promising results. It demonstrates that the mitigation plan developed by Transpower many years ago would effectively lower the GIC at a number of substations in the lower South Island. However due to the regional focus of the mitigation carried out the impact is localised to a small fraction of the overall New Zealand power network. Locations further north (i.e., outside the locations shown in Figure 2) have negligible changes in GIC that are always less than 0.5%, suggesting that the HTPLSI mitigation plan is less effective outside the region for which it was developed.

4 Disconnect Redundant Lines New Zealand (DRLNZ) mitigation plan

The results presented for the HTPLSI mitigation plan show some large GIC decreases in the lower South Island. Extending the basic idea behind the HTPLSI mitigation plan, an attempt was made to mitigate GIC throughout the rest of the New Zealand network. The previous mitigation plan largely leveraged the occurrence of parallel transmission lines. The plan involved disconnecting transmission lines if there are multiple circuits connecting two substations, i.e., decreasing redundancy, increasing network impedance, and largely decreasing GIC magnitudes. In this section this mitigation idea has been extended by identifying all locations across the nationwide transmission network for which there are multiple parallel transmission lines between substations and disconnecting one of those lines. This would result in the disconnection of 38 (out of the 143) South Island transmission lines and 83 (of the 270) North Island transmission lines for a total of 121 line disconnections. Clearly this plan would involve vastly more network changes than the four transmission lines disconnected in the HTPLSI mitigation plan discussed in Section 3. Due to the large number, the locations are not listed or shown but they cover all regions of the New Zealand power network. This mitigation strategy will be referred to as the "Disconnect Redundant Lines New Zealand" (DRLNZ) mitigation plan. It is important to note that unlike the HTPLSI mitigation plan, ROX T10 would not be disconnected from the network in the DRLNZ mitigation plan. The mitigation in this strategy has been limited to just transmission line disconnection.

In Figure 3 we present the change in the substation average 60-minute mean GIC for the DRLNZ mitigation plan. In this figure only substations that exceed a 50 A GIC change are labelled. This is a change from Figure 2 which displayed those with 5% or more GIC changes and was made because of the large number that reach the 5% threshold (68 substations) compared to the 25 substations exceeding 50 A GIC changes. It is worth mentioning that all five substations under the HTPLSI mitigation plan that exceed 50 A GIC changes also exceed the 5% threshold and therefore are shown in Figure 2.

Initially focusing on the lower South Island we can see larger decreases in the substation-level GIC than are shown in Figure 2. Table 4 includes information on all lower South Island earthed substations given by the blue circles in Figure 2. In Table 4 we compare the substation average 60-minute mean GIC changes between the HTPLSI and DRLNZ mitigation plans. Negative values indicate decreases in GIC after the mitigation plans are implemented. The last column shows the difference between the two mitigation plans; here a negative value indicates a further decrease in GIC using the DRLNZ mitigation plan. With the exception of Benmore (BEN) and Tekapo A (TKA) every substation shows either no change or decreases in GIC for the DRLNZ plan compared with the HTPLSI plan. This indicates that this mitigation plan would be typically more effective for the lower South Island, than the HTPLSI mitigation plan at reducing GIC during the event at the cost of a less resilient network as the parallel lines that provide additional security to potential network faults have been removed from service.

Substations in the upper South Island and North Island are also shown in Figure 3. Absolute decreases, or no change, in GIC magnitudes due to the DRLNZ plan are found at 80 of the 85 earthed substations throughout New Zealand with the only increase over 50 A occurring at Maraetai (MTI) near the central North Island (shown with a red arrow). This substation consists of 10 earthed transformers and as such we suggest that an increase of 100 A shared over 10 transformers is not likely to be significant from a transformer risk perspective.

Table 4: Substation average 60-minute mean GIC changes for the HTPLSI and DRLNZ mitigation plans. Negative values indicate decreases in GIC when the various mitigation plans are implemented. The last column shows the difference between the two mitigation plans and a negative value here indicates the further decreases in GIC with the DRLNZ mitigation plan. This table has been limited to the earthed substations in the lower South Island (blue circles in Figure 2).

Substation	Abbreviation	HTPLSI % [A]	DRLNZ % [A]	Difference % [A]
Tiwai	TWI	-3% (-20 A)	-16% (-120 A)	-13% (-100 A)
Invercargill	INV	-2% (-10 A)	-10% (-40 A)	-8% (-30 A)
North Makarewa	NMA	-25% (-60 A)	-33% (-80 A)	-8% (-20 A)
Gore	GOR	0% (0 A)	-33% (-20 A)	-33% (-20 A)
Waipori	WPI	-50% (-40 A)	-50% (-40 A)	0% (0 A)
South Dunedin	SDN	-30% (-430 A)	-35% (-500 A)	-5% (-70 A)
Halfway Bush	HWB	-30% (-370 A)	-38% (-470 A)	-8% (-100 A)
Manapouri	MAN	-14% (-200 A)	-14% (-200 A)	0% (0 A)
Roxburgh	ROX	-3% (-30 A)	-28% (-210 A)	-25% (-180 A)
Clyde	CYD	-18% (-140 A)	-33% (-260 A)	-15% (-120 A)
Cromwell	CML	-8% (-20 A)	-19% (-50 A)	-11% (-30 A)
Naseby	NSY	11% (20 A)	0% (0 A)	-11% (-20 A)
Waitaki	WTK	9% (20 A)	-9% (-20 A)	-18% (-40 A)
Aviemore	AVI	0% (0 A)	-33% (-40 A)	-33% (-40 A)
Benmore	BEN	-25% (-30 A)	33% (40 A)	58% (70 A)
Timaru	TIM	2% (10 A)	-9% (-40 A)	-11% (-50 A)
Ohau C	OHC	0% (0 A)	-29% (-80 A)	-29% (-80 A)
Ohau B	OHB	-5% (-40 A)	-20% (-160 A)	-15% (-120 A)
Ohau A	OHA	-5% (-40 A)	-29% (-240 A)	-24% (-200 A)
Tekapo B	TKB	0% (0 A)	-9% (-40 A)	-9% (-40 A)
Tekapo A	TKA	0% (0 A)	17% (20 A)	17% (20 A)

Ideally any mitigation efforts should also result in less transformers reaching the transformer danger levels discussed in Mac Manus et al. (2022b) or at least a lower danger level. These danger levels are a set of industry provided GIC magnitudes and durations to avoid because they should all elevate the transformer oil temperature to 180°C (see Table 1 in Mac Manus et al. (2022b)). While no single danger level is inherently worse than any other, a lower danger level is seen as more preferable due to the lower mean current over a longer duration required to drive the transformer to dangerous temperature levels or cause the transformer to saturate and draw large reactive power. In Figure 4 the number of transformers reaching the various danger levels for the nine extreme storm scenarios are given and compared with the values based on the original model results, which were calculated without taking any mitigation in account. For all scenarios and danger levels the number of transformers at each danger level decreases for the DRLNZ mitigation plan. In Figure 4 the coloured stars indicate the no mitigation case, while the coloured diamonds represent the DRLNZ mitigation plan. The vertical solid black lines represents the difference between the two values. A longer black line indicates a larger difference between the DRLNZ mitigation plan and the original no mitigation case, and shows evidence of a more effective mitigation approach. The results show that the DRLNZ mitigation plan, while effective in all scenarios and all danger levels, does not provide any more protection of the network for any individual danger level, i.e., there are more transformers at danger level 1 than (say) level 5 for any scenario, even after mitigation.

Figure 4 shows large decreases across all scenarios and danger levels. With this mitigation method the number of transformers at risk of damaging GIC is significantly reduced. Note, however, that this mitigation plan is rather extreme as it involves disconnecting approximately 30% of New Zealand's high voltage transmission lines. The results and a list of the transmission lines disconnected with the DRLNZ mitigation plan were passed on to Transpower so they could determine if it was a feasible NZ-wide mitigation plan. Because it involves removing so many transmission lines from service the overall network voltage stability would be seriously reduced and the risk of network failure due to other possible faults would be significantly increased. Feedback from Transpower was that this plan was not possible for real-world operation. Due to the impracticality of applying the DRLNZ mitigation plan during an extreme geomagnetic storm a more realistic version was required that would better provide adequate system stability in the New Zealand power network.

5 Transpower 2022 New Zealand (TP2022NZ) mitigation plan

A new mitigation strategy, which we have termed the Transpower 2022 New Zealand (TP2022NZ) mitigation plan, was developed in collaboration with Transpower during a site visit in August 2022. The visit involved the space weather research team going to Transpower to work with a team of system operators in their simulation room. This allowed a real time discussion of possible mitigation changes, with the suggestions starting from the research team but quickly flowing from both sides as we progressed. These suggested changes were then tested in the Transpower network simulation model, allowing the system operators to immediately check if network stability was still maintained and power distribution was unaffected. Suggestions from the Transpower system operators could also be tested with the GIC model in real time, ensuring the idea produced an appropriate GIC decrease. More modifications were progressively added with network stability tested at every iteration along with the GIC model to confirm GIC decreases at the key transformers of interest. This finally resulted in the equipment disconnections given in Table 5.

Altogether this plan consists of 24 line disconnections as well as disconnecting the series winding of one transformer GOR (which stops GIC flow between the 110 and 220 kV nodes at GOR). A number of the transmission lines disconnected are the only direct connections between two substations (those given in the table with "circuit 1 of 1"). One of the benefits of working directly with Transpower in real time was the ability to quickly identify if transmission lines could be disconnected without destabilizing the power network. Disconnecting transmission lines that are the sole connection between two substations is something the research team would not have considered without Transpower's network knowledge. Figure 5 shows the approximate location of the disconnected transmission lines in the TP2022NZ mitigation plan.

The change in the substation average 60-minute mean GIC for the TP2022NZ mitigation plan is presented in Figure 6. In this figure only substations that exceed a 50 A GIC change are labelled.

For the TP2022NZ mitigation plan the average 60-minute mean GIC summed up at all 279 earthed transformers across 85 substations is 19,860 A. This is a 16% decrease from the no mitigation total of 23,550 A. Despite involving significantly less line disconnections than the DRLNZ mitigation plan, the TP2022NZ plan further reduces the GIC at some key locations. The Halfway Bush (HWB) and Roxburgh (ROX) substations show

Table 5: Equipment disconnections for the TP2022NZ mitigation plan.

Substation 1	Substation 2	Abbreviation	Line Voltage (kV)	Circuit
Brownhill road	Whakamaru	BHL-WKM	220	1 of 2
Huntly	Stratford	HLY-SFD	220	1 of 1
Brunswick	Stratford	BRK-SFD	220	1 of 3
Redclyffe	Wairakei	RDF-WRK	220	1 of 1
Haywards	Linton	HAY-LTN	220	1 of 1
Haywards	Wilton	HAY-WIL	220	1 of 1
Bream Bay	Huapai	BRB-HPI	220	1 of 1
Henderson	Huapai	HEN-HPI	220	1 of 1
Maungatapere	Maungaturoto	MPE-MTO	110	1 of 2
Maungatapere	Maungaturoto	MPE-MTO	110	2 of 2
Mangamaire	Masterton	MGM-MST	110	1 of 1
Hepburn Road	Mount Roskill	HEP-ROS	110	1 of 2
Hepburn Road	Mount Roskill	HEP-ROS	110	2 of 2
Wanganui	Waverley	WGN-WVY	110	1 of 1
Manapouri	North Makarewa	MAN-NMA	220	1 of 3
Roxburgh	Three Mile Hill	ROX-TMH	220	1 of 2
Gore	North Makarewa	GOR-NMA	220	1 of 2
Gore	Three Mile Hill	GOR-TMH	220	1 of 2
Benmore	Twizel	BEN-TWZ	220	1 of 1
Islington	Kikiwa	ISL-KIK	220	1 of 1
Ashburton	Islington	ASB-ISL	220	1 of 1
Halfway Bush	Three Mile Hill	HWB-TMH	220	1 of 1
Halfway Bush	Roxburgh	HWB-ROX	110	1 of 2
Halfway Bush	Roxburgh	HWB-ROX	110	2 of 2
Gore	-	GOR T11	-	-

a further 28% (360 A) and 35% (270 A) decrease. In the North Island, Redclyffe (RDF) and Henderson (HEN) show further decreases of 25% (160 A) and 25% (240 A).

Looking specifically at individual transformer average 60-minute mean GIC, we see some important improvements with the TP2022NZ mitigation plan compared with the interesting but not operationally practical DRLNZ mitigation plan. GIC at Halfway Bush (HWB) T6 decreases (by a further 280 A) as does Kikiwa (KIK) T2 (-150 A), Henderson (HEN) T1 (-110 A) and HEN T5 (-110 A). Roxburgh (ROX) T10 also decreases (by a further 100 A). Overall eight transformers show further decreases of 100 A or more while only South Dunedin (SDN) T2 (+110 A) and Islington (ISL) T6 (+170 A) show increased GIC by more than 100 A.

In Figure 7 the number of transformers reaching the various danger levels for the nine extreme storm scenarios is given and compared with the values for the original model output. In this figure the coloured stars indicate the no mitigation case, while the coloured squares represent the TP2022NZ mitigation plan. As before, the vertical solid black lines represents the difference between the two values. A longer black line indicating a larger difference between the TP2022NZ mitigation plan and the original no mitigation case. Like Figure 4 for the majority of the nine scenarios and danger levels the number of transformers has decreased using the TP2022NZ mitigation plan. There are three exceptions to this, seen where the coloured squares are at a slightly higher transformer number than the coloured stars, i.e., indicating a smaller increase in transformers in danger. This occurs for danger level 3 during the 1989 EYR scenario, and danger levels 3 and 4, during the 2003 EYR scenario. In all of these cases the increases are small, and corresponding to the least likely scenario where the magnetic field variation across the country is constant (EYR, see Mac Manus et al. (2022b) for more details).

In summary, the TP2022NZ mitigation plan is effective at reducing GIC at the transformers of high concern, while involving minimal power network modifications. Currently Transpower are in the last stages of making TP2022NZ their official geomagnetic disturbance management plan, a much needed update to the current, but over 15 year old, HTPLSI mitigation plan, discussed earlier in Section 3.

6 GIC Blockers

Installing a capacitor blocking device at the neutral point of a transformer would directly block DC current while still allowing AC current to pass. As a result, no GIC would flow through the transformer into the network. While protecting that specific transformer from GIC related damage, installing capacitor blocking devices would have an impact on other transformers, with GIC diverted to other transformers in the same substation as well as to those in nearby substations (referred to as the Whack-A-Mole effect). As GIC capacitor blocking devices are expensive it is unrealistic to install them on every transformer neutral point in a network. According to our industry partners, finding optimal placements for an affordable number of devices is vital. While capacitor blockers can be effective tools against GIC the do come with some network stability risks. High voltages can build up around the capacitors if over-voltage conditions are met generating large currents in transformer winding. This can occur during ground vaults and lightning strikes.

One potential route forward is to install the blocking devices on transformers based on their GIC magnitude calculated in the geomagnetic storm scenarios used in this study. Our Transpower collaborators asked us to investigate the additional reduction in GIC levels, if in addition to the TP2022NZ mitigation plan, capacitor blocking devices were installed on transformers exhibiting the largest GIC values. To do this we looked at the single maximum GIC each transformer measured for the nine extreme storm scenarios modelled under the TP2022NZ mitigation plan (discussed in Section 5). The impact of installing capacitor blocking devices on all transformers in which the mean of their nine maximum GICs exceed 500 A was simulated. This threshold value was selected at the suggestion of Transpower staff.

For this modeling study we assume that each capacitor blocking device is "on" during the whole modeled duration and therefore zero GIC flows through those transformers. This would result in 31 transformers throughout New Zealand effectively switching from earthed to unearthed. As a consequence of adding the capacitor blocking devices, total network average 60-minute mean GIC reduces from 19,860 A, across 279 transformers under the TP2022NZ mitigation plan to 16,000 A, for the remaining 248 earthed transformers. This amounts to a 3,860 A decrease, i.e., a further 16% reduction on top of the initial 16% decrease (from 23,550 A) achieved by the TP2022NZ plan alone. In terms of individual transformers that exceed 100 A GIC, 15 show increases in their average 60-minute mean GIC. Some examples include the transformers of Halfway Bush (HWB) T3, Invercargill (INV) T3, INV T5, Islington (ISL) T3, ISL T7, Henderson (HEN) T2, and HEN T3. These transformers share some similarities in that all of them are located within substations for which one or more capacitor blocking devices were installed in our simulation. This is a rather unavoidable consequence of the use of blocking devices as the substation would have less transformers for the GIC to pass through to earth, such that the GIC passes through other local transformers instead. An alternative approach would be to select a few substations and install capacitor blocking devices on all earthed transformers to effectively unearth the whole substation.

We explore this idea by modeling the installation of 14 capacitor blockers on all transformers at the Invercargill (INV), Halfway Bush (HWB), South Dunedin (SDN), and Henderson (HEN) substations. In this case only four transformers show increases in the average 60-minute mean GIC exceeding 100 A and it is worth noting that none show an increase to a higher danger level. We suggest that blocking all transformers at a particular high-risk substation is a potential approach in order to avoid large increases at other transformers in that substation. In Figure 8 we see how many transformers would reach danger levels 1-5 as a result of the installation of the 14 capacitor blocking devices at the locations described above. Decreases in the number of transformers at risk are seen for all scenarios

If a transformer is at risk of damage due to GIC, it could trip and essentially be removed from service (or worse, sustain sufficient damage such that it cannot continue to operate). This can be simulated in our network modeling by removing the earth connection so that zero GIC flows through the transformer neutral. However, in a similar way to the capacitor blocking described above, the removal of a given transformer can have follow-on effects as any GIC flowing through that substation would be shared across fewer transformers. The increased GIC at the remaining, earthed transformers could place the remaining transformer under more stress, potentially leading to a cascading failure of further transformers. This can be considered as a Whack-A-Mole effect in which reducing or blocking GIC in one location can increase it at another.

7 GIC Whack-A-Mole phenomena

In this section the Whack-A-Mole effect is investigated in more detail using the nine extreme storm scenarios discussed in Mac Manus et al. (2022b). For each scenario the time instance corresponding to the maximum GIC was modelled repeatedly, each time isolating the transformer with the largest GIC and removing it from the network (i.e., simulating a capacitor blocking device or a transformer failure and unearthing it). This is repeated until all transformers are unearthed. The maximum transformer GIC and the sum of GICs for the whole network are calculated as transformers are progressively removed.

In Figure 9 we show the maximum GIC and sum of GICs in the New Zealand power network for the October 2003 ROGERS extreme storm scenario. This scenario represents a ”middle of the road” extreme storm. The original scenario run without blockers produced a total GIC sum of 23,720 A and a maximum transformer GIC of 1890 A, which occurred at the SDN T2 transformer. Therefore, in order to block that GIC route, a capacitor blocker device is specified at SDN T2 and the model simulation is rerun. The modification caused the total GIC to decrease by 1360 A to 22,360 A. However the maximum individual transformer GIC increased to 2070 A. This increase occurred at the HWB T6 transformer in the Halfway Bush substation. As this substation is located only a few km from South Dunedin (SDN), and directly connected to it, a portion of the GIC previously flowing through the SDN transformer has been redirected to HWB. The next two transformers removed in sequence are also located at the HWB substation and once this complete substation-blocking occurs, the first large decrease in the transformer-level maximum GIC occurs with a drop from 1870 A to 640 A, the latter being the value found at the Islington #6 transformer (ISL T6). Following this, up until 50 transformers are simulated with capacitor blockers, the sum of GICs in the network roughly decreases linearly at a rate of ∼210 A per capacitor blocker. The imposition of the next sequence of 50 capacitor blockers acts to decrease the sum of GICs at half that rate, ∼105 A per device. This continues to decrease for the next 100 capacitor blockers at ∼40 A per device until only a sum of 830 A GIC remains throughout the remaining 79 earthed transformers in the power network, 3.5% of the original GIC sum without capacitor blockers. As more capacitor blocking devices are installed in the simulation the decrease in the total GIC per device is reduced as transformers with the largest GIC maximums are already isolated from earth. Once all 279 earthed transformers are simulated with capacitor blocking devices the total GIC sum is zero.

In the top panel of Figure 9 a large spike in the largest transformer-level GIC across the network can be seen once 30 capacitor blockers have been installed. This occurs at a single Manapouri (MAN) transformer, located in the lower South Island, once all the other transformers at the MAN substation have had capacitor blocking devices installed. The original substation GIC at MAN for this extreme storm scenario was rather high at 1680 A, however it was initially shared amongst nine transformers. When only one earthed transformer remains unblocked, all the GIC (i.e., all 1160 A), will be directed through this transformer. This is the potential issue previously mentioned in which installing capacitor blockers on only some of the transformers within a substation can add stress to the remaining transformers. Manapouri is a perfect example of this as it has the fourth largest substation GIC for this 2003 ROGERS scenario, behind South Dunedin, Halfway Bush, and Islington. These three substation contain one, two and six earthed transformers, respectively, while Manapouri contains nine. Therefore, a substation which might not have overly large transformer-level GIC initially due to sharing can suddenly experience its maximum GIC increasing significantly if all of the other transformers are removed from service (either tripped during a geomagnetic storm or operating with a capacitor blocking device). Excluding this single spike at Manapouri, the upper panel of Figure 9 shows that by isolating just three transformers (HWB and SDN) the maximum individual transformer-level GIC is reduced by 70%.

Figure 10 displays the maximum and total sum of GIC in the power network for all nine extreme storm scenarios as a percentage of the initial situation. In this figure the modelled GIC without any capacitor blockers installed is represented as 100%. With the exception of a few spikes, the maximum transformer-level GIC magnitude drops below 60% of the initial value after 15 capacitor blockers are installed. The total sum of GIC drops off near-linearly for the three constant latitude extreme storm scenarios (e.g., 1989 EYR GIC etc). For these scenarios the distribution of transformer GIC maximums across the network shows less spread, with the majority of transformers in the middle 50 percentile in terms of GIC experienced. For the latitude varying scenarios (ROGERS and NERC), the individual transformer-level GIC maximums are shifted towards the extremes. In these cases locations south of Eyrewell have larger GIC while those north of Eyrewell have smaller GIC, when compared with the constant latitude scenario. This leads to larger decreases in the total sum of GIC per capacitor blocker for the first 50 installations, approximately the same decreases for the next 50 installations and lower decreases for the remainder installations when compared against the constant latitude extreme storm scenarios, hence the non-linear drop-off of the sum GIC in the network.

8 Summary

Effective mitigation can significantly reduce modelled GIC magnitudes and durations experienced at specific transformers of interest. Mitigation can involve disconnecting transmission lines, transformers and/or installing capacitor blocking devices on transformers to protect them from GIC. Reducing GIC magnitude is important as elevated levels over long periods can cause transformer temperature increases that may reduce the life span of the transformer, potentially leading to increased failures in the recovery phase from an extreme space weather event, and not just the more active main phase (Molinski, 2002; Girgis & Vedante, 2013; FERC, 2015)

The simulation results presented in this study looked at four key mitigation strategies. All four were tested using a network model by applying the nine extreme storm scenarios discussed in Mac Manus et al. (2022b). First, the present Transpower mitigation plan, which we termed the HTPLSI mitigation plan was tested. This mitigation plan focused on the lower South Island and showed individual transformer-level GIC decreases of up to 30%. Using the principals behind this mitigation plan, all parallel transmission lines throughout New Zealand in the network model were disconnected, termed the DRLNZ mitigation plan. This showed GIC decreases in 80 of the 85 earthed substations throughout New Zealand. At the transformer level, this mitigation strategy leads to a reduced number of transformers at all danger levels for all extreme storm scenarios.

However, after discussions with Transpower, the DRLNZ mitigation plan was found to be unfeasible as it would cause system instability and would not allow for the continued supply of power throughout New Zealand. By working closely with Transpower control room staff a more practical mitigation strategy, termed the TP2022NZ mitigation plan was developed, that specifically targeted transformers that our modelling showed were at risk of GIC damage. This revised strategy involves only 24 line disconnections compared to the 121 under the DRLNZ mitigation plan. Under the TP2022NZ strategy, the sum of the substation average 60-minute mean GIC in the network decreased by 16% relative to the original network. Compared to the DRLNZ mitigation plan, the TP2022NZ targeted mitigation strategy results in larger decreases in GIC at the key substations of Halfway Bush, Roxburgh, Redclyffe, and Henderson. Overall, 27 of the 30 most at risk transformers in terms of average 60-minute mean GIC show decreases with the TP2022NZ mitigation plan. The TP2022NZ mitigation strategy is now an operational procedure available to use in the national control room to manage GIC, replacing the earlier HTPLSI approach.

Using this TP2022NZ mitigation plan, an additional step was considered that involved simulating capacitor blockers that could be installed on 14 specific transformers. A further 16% decrease in substation GIC reduced the total sum of GIC in the network to 68% of the original, non-mitigation GIC total sum.

A final experiment was carried out in which transformers were progressively simulated as having capacitor blocking devices installed in order to investigate how the maximum transformer GIC and total sum changed throughout the network. It was determined that with just three capacitor blockers on the transformers with the largest GIC, the remaining transformer-level GIC maximum in the network can be reduced by 50%. After ∼30 transformers were blocked, the sum 60-minute mean GIC in the network was also reduced by 50%.

The mitigation plans discussed in this study have shown that GIC can be effectively reduced with minimal network changes. We strongly recommend that any mitigation attempts be carried out in collaboration with the power network operators as this allows the development of mitigation plans that will reduce GIC whilst having minimal impact on the general operation and distribution of power throughout the network. Andrew Renton, Transpower's Senior Principal Engineer has provided the following statement regarding this relationship. "The potential threat that GIC pose to the power system is taken seriously by New Zealand's electricity transmission system owner and operator. We appreciate the positive collaboration between the scientific community and industry and our ability to contribute to increasing the understanding of the effect this phenomena has on electricity systems. Working with the Solar Tsunami team we have been able to leverage the latest research to model the power systems response to different configurations and system events and develop a system configuration to minimise GIC currents at key locations and maximising our ability to maintain a stable power system during an event. This work has now been published in our Operational Plan PR-DP-252 Manage Geomagnetic Induced Currents".

In light of this study Transpower is considering further mitigation approaches, with blocking capacitors as one example. Furthermore, splitting the network into smaller isolated regions during a geomagnetic event while still providing some local generation for essential services is also being considered.

As a final note, we feel we should add a clarification which has come up after discussions with colleagues at conferences. Multiple space weather scientists have commented that the New Zealand mitigation approach seems at odds to that being discussed in other parts of the world. To paraphrase, others mention "New Zealand is switching things off, while we want everything running". We think this is a small misunderstanding with important implications. In the New Zealand mitigation approach we remove transmission lines which are effectively redundant, in order to decrease GIC peak magnitudes in transformers. As we understand it, the urge to have "everything running" during a large space weather event is more focused on generation, such that there is a large reserve of reactive power able to compensate for increased reactive power requirements during space weather events (see for example, Molinski (2002) for discussions around space weather and reactive power). We believe these two approaches are complementary, and not contradictory; removing transmission lines can decrease GIC magnitudes within the network (which will, in practice, decrease reactive power needs), but increasing available generation allows reactive power reserves, and may also provide some additional operational stability/flexibility.

Data Availability

The New Zealand electrical transmission network's DC characteristics were provided to us by Transpower New Zealand with caveats and restrictions. This includes requirements of permission before all publications and presentations. In addition, we are unable to provide the New Zealand network characteristics due to commercial sensitivity. Requests for access to these characteristics need to be made to Transpower New Zealand. At this time the contact point is Michael Dalzell (Michael.Dalzell@transpower.co.nz).

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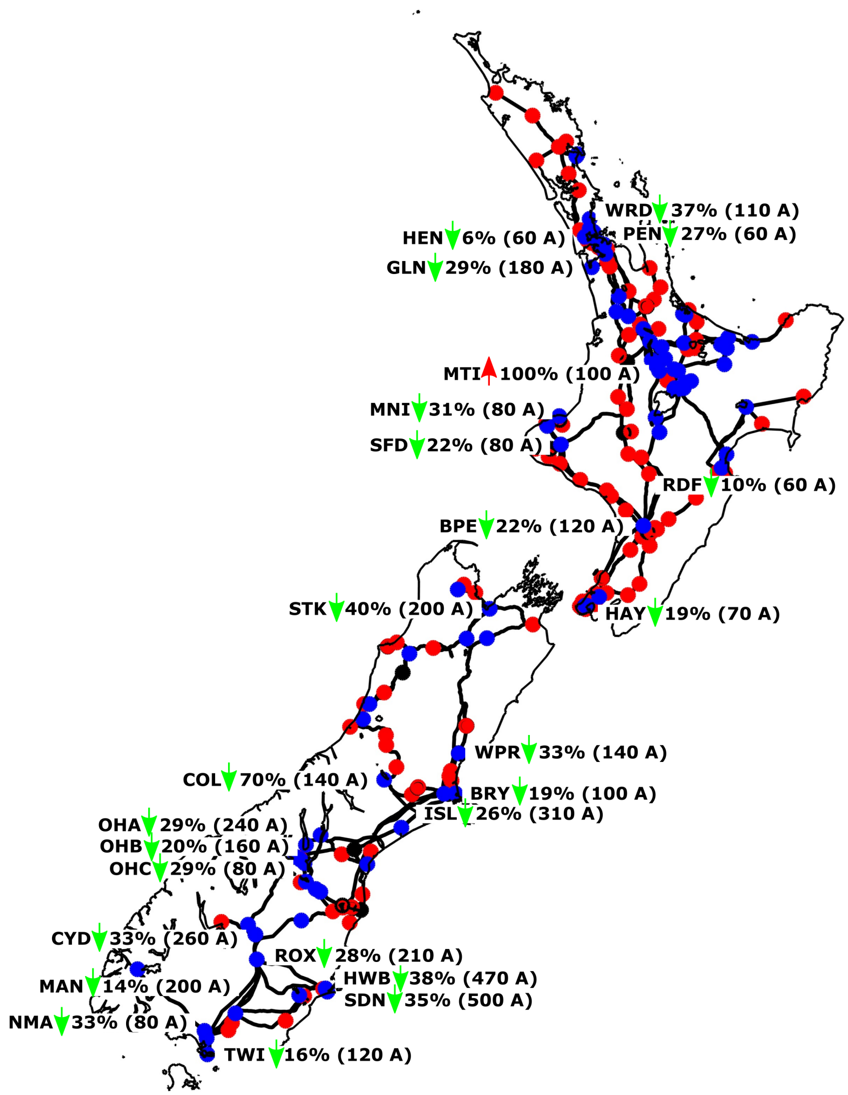


Figure 3: Change in the substation average 60-minute mean GIC for the DRLNZ mitigation plan. Substations with a 50 A or larger GIC change are labelled. Earthed substations are represented by blue circles while unearthed substations and T-junctions are given by red and black circles, respectively. A downwards green arrow indicates a decrease by the percent shown while the single upwards red arrow indicates an increase. The value in brackets corresponds to the absolute substation GIC change.

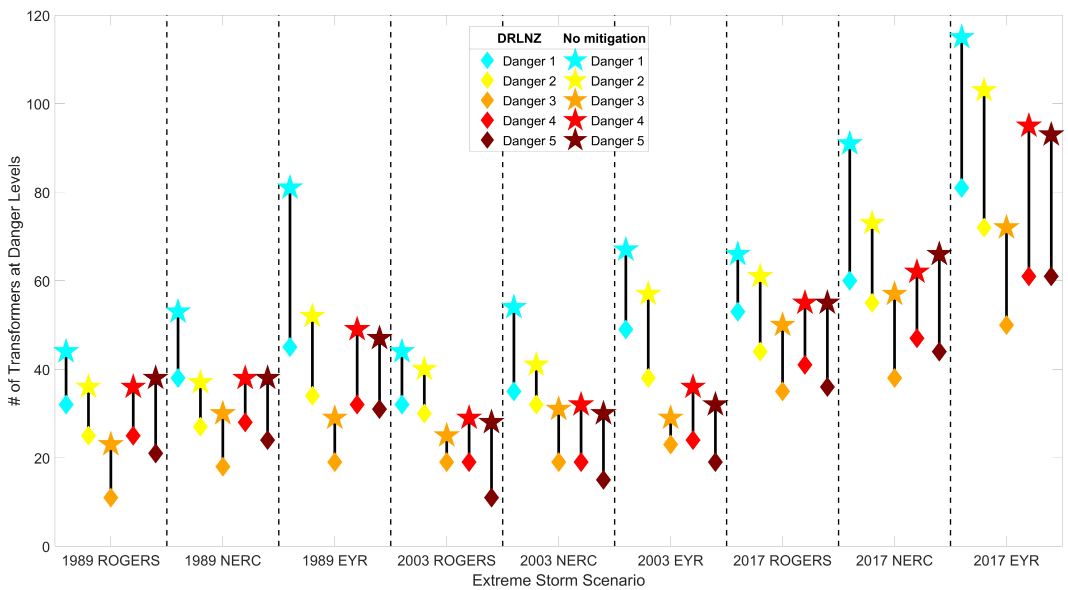


Figure 4: Number of transformers that reach the GIC Danger levels for the 9 extreme storm scenarios described in Mac Manus et al. (2022b). Here, the coloured stars correspond to the no mitigation case while the coloured diamonds are for the DRLNZ mitigation plan. The vertical solid black lines connecting two points is an indicator of the difference between the two cases. A longer black line corresponds to a larger difference in the number of transformers reaching the particular danger level, and thus a more effective mitigation approach.

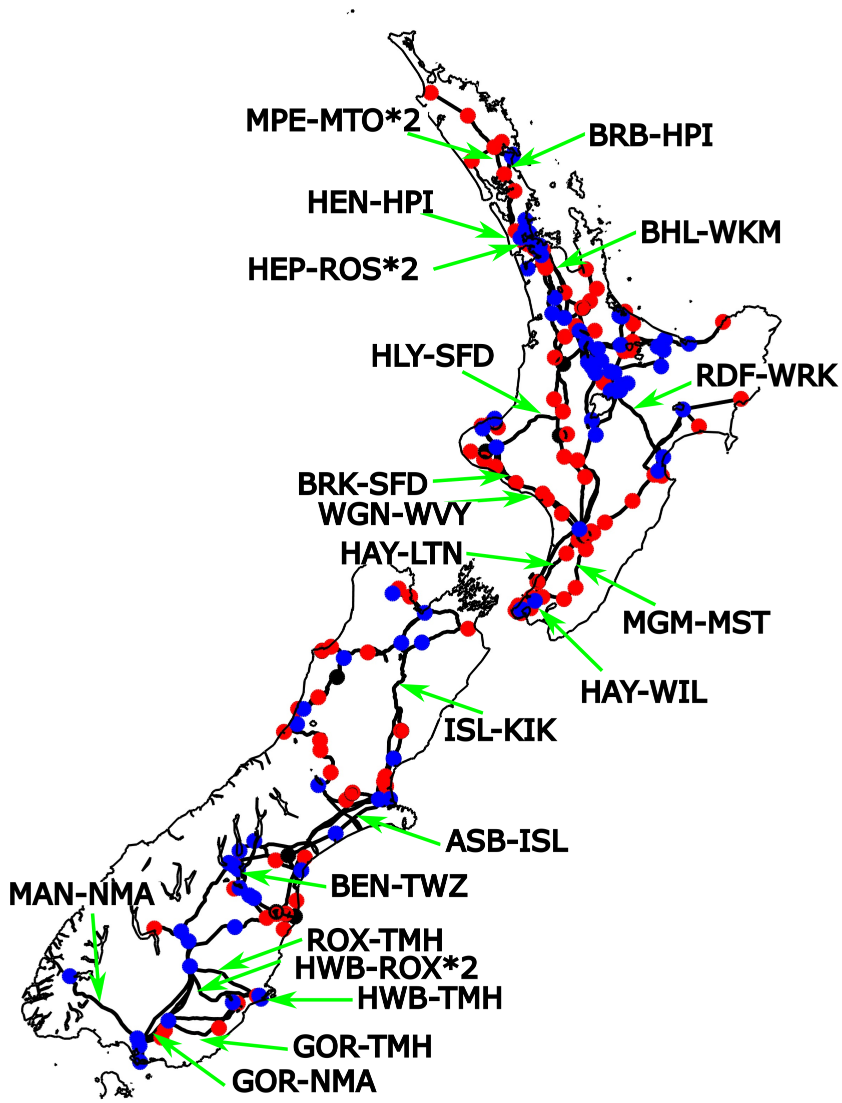


Figure 5: TP2022NZ mitigation plan showing the approximate location of disconnected equipment. Earthed substations are represented by blue circles while unearthed substations and T-junctions are given by red and black circles.

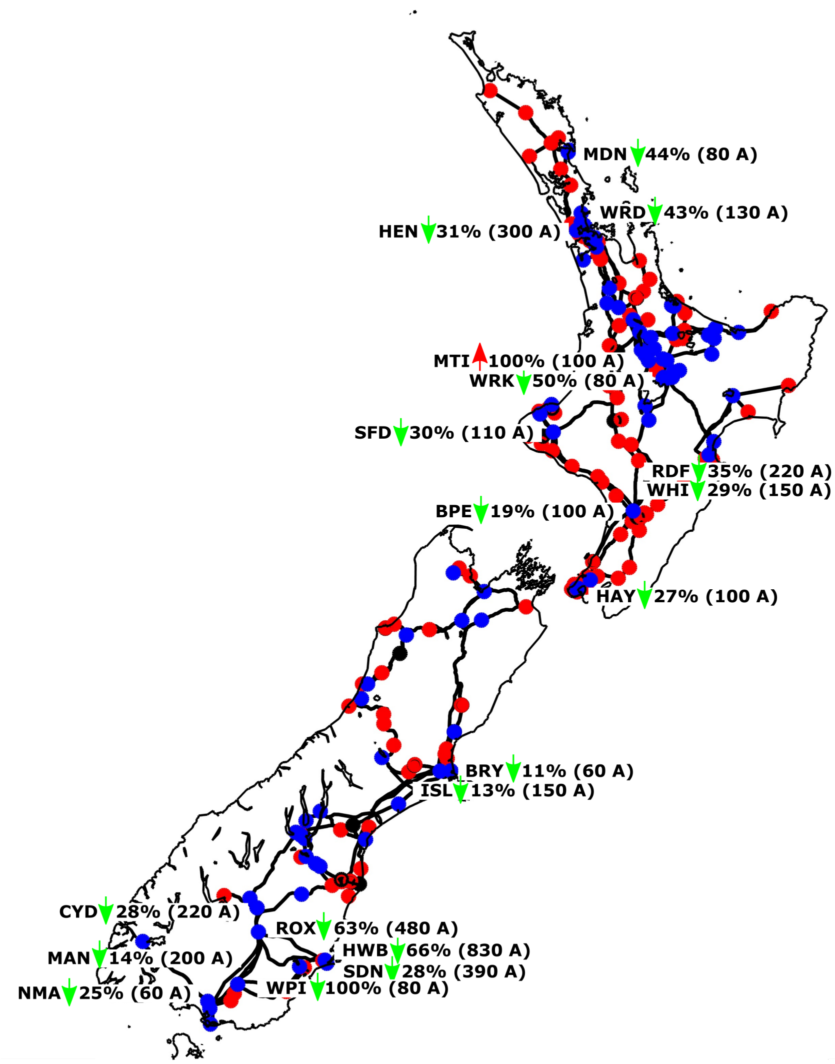


Figure 6: Change in the substation average 60-minute mean GIC for the TP2022NZ mitigation plan. Substations with a 50 A or larger GIC change are labelled. A downwards green arrow indicates a decrease by the percent shown while the single upwards red arrow indicates an increase. The value in brackets corresponds to the absolute substation GIC change.

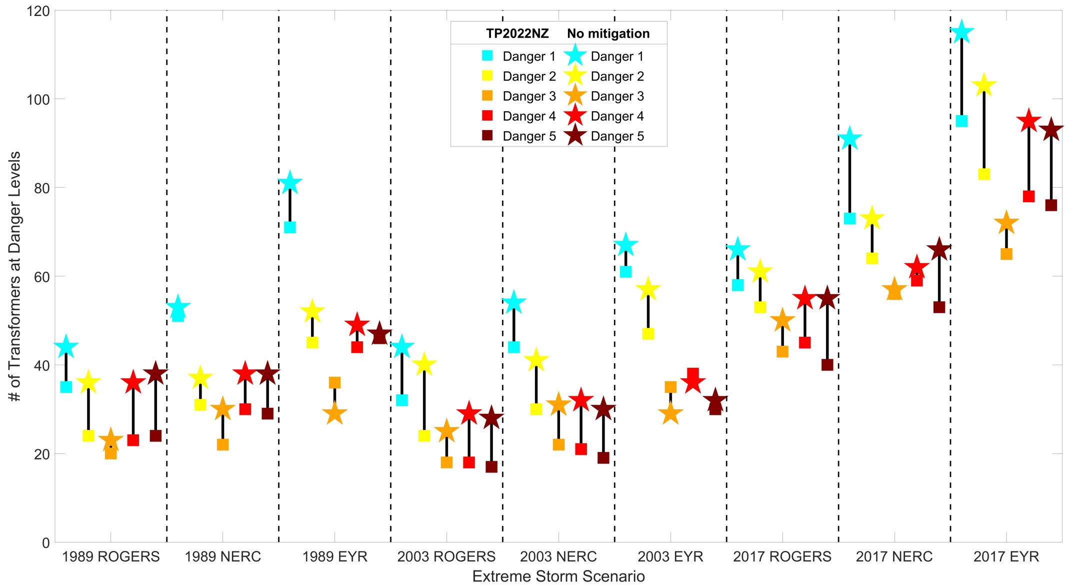


Figure 7: Number of transformers that reach the GIC danger levels for the 9 extreme storm scenarios described in Mac Manus et al. (2022b). Here, the coloured stars correspond to the no mitigation case while the coloured squares are for the TP2022NZ mitigation plan. The vertical solid black lines connecting two points is an indicator of the difference between the two cases. A longer black line corresponds to a larger difference in the number of transformers reaching the particular danger level, and thus a more effective mitigation approach.

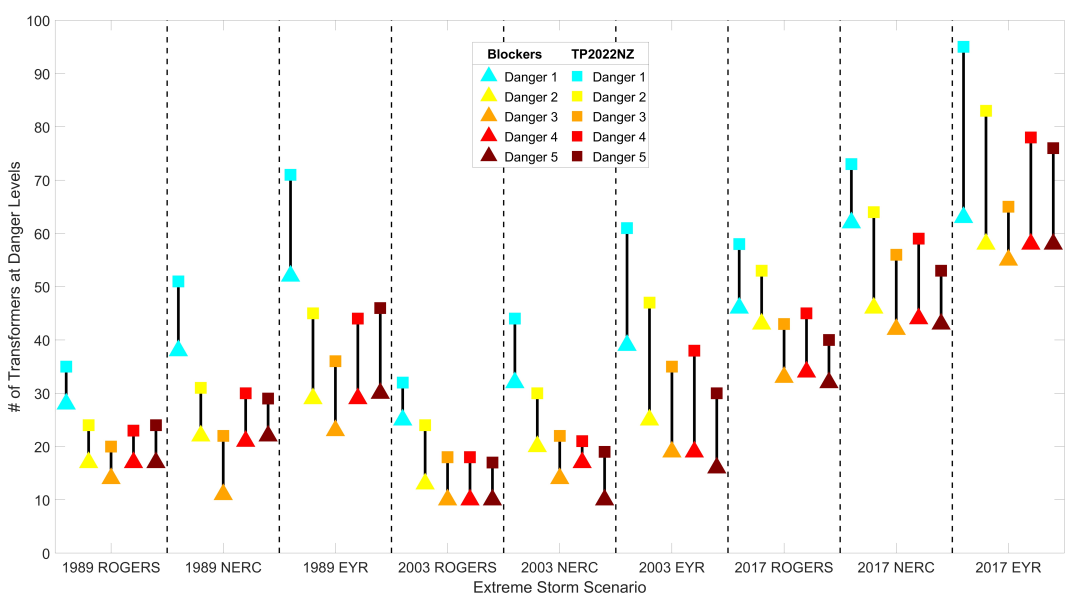


Figure 8: Similar to Figure 7 except the initial state is the TP2022NZ mitigation plan which is compared against a simulation with the addition of 14 capacitor blocking devices on specific transformers in 4 substations.

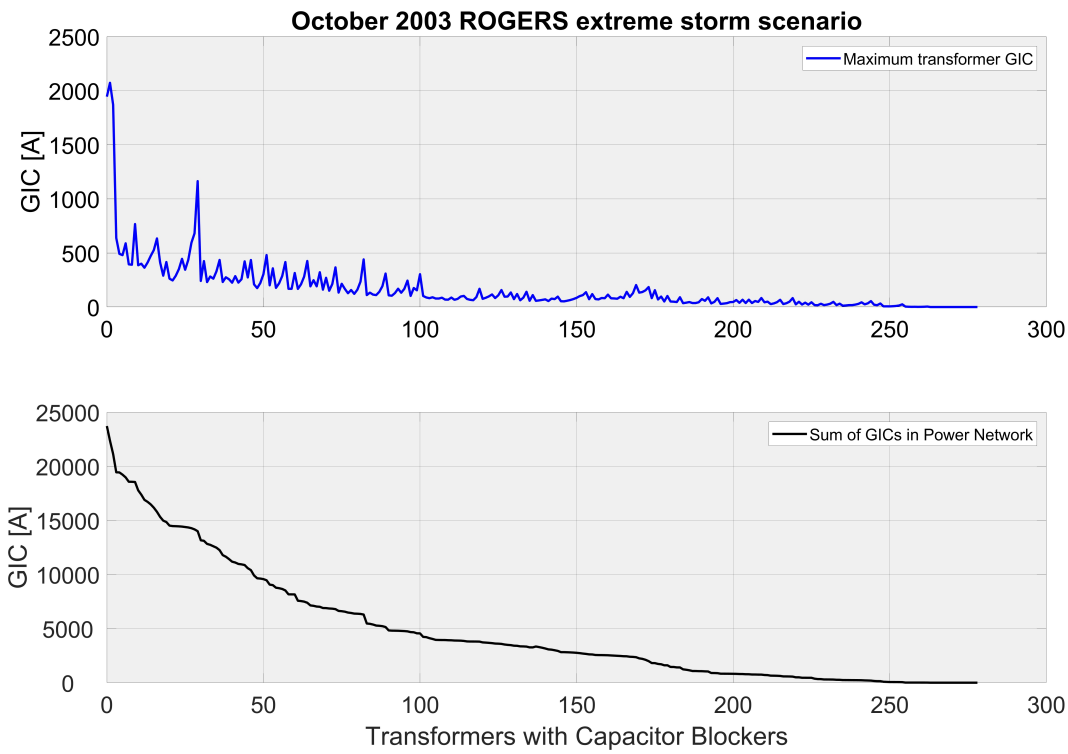


Figure 9: GIC in the New Zealand power network for the October 2003 ROGERS extreme storm scenario as transformers have capacitor blocking devices installed. In the top panel is the largest transformer-level GIC across the network while the bottom panel is the total sum of GIC in the network. Note this combines the results from the North and South Island, which are essentially two independent electrical networks.

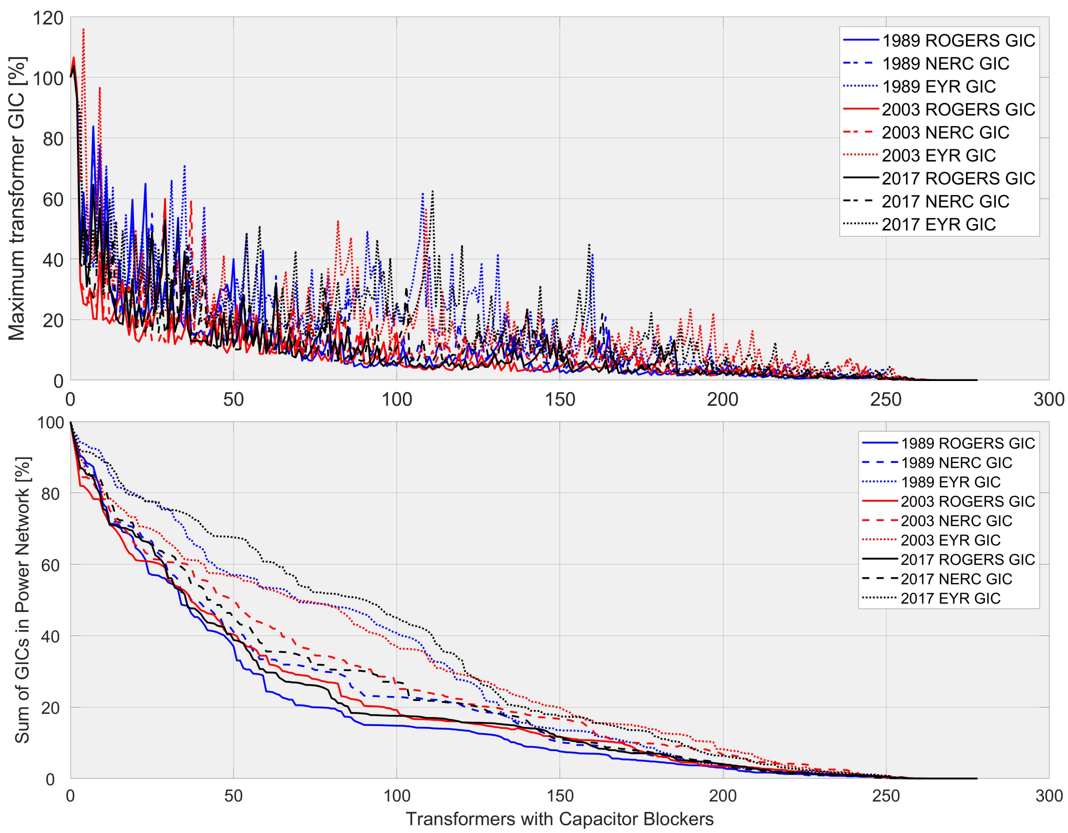


Figure 10: As Figure 9 but for all nine extreme storm scenarios modelled. In this case the maximum and sum of GIC have been normalised to their original values and represented as a percentage of the initial value.

Figure 1.

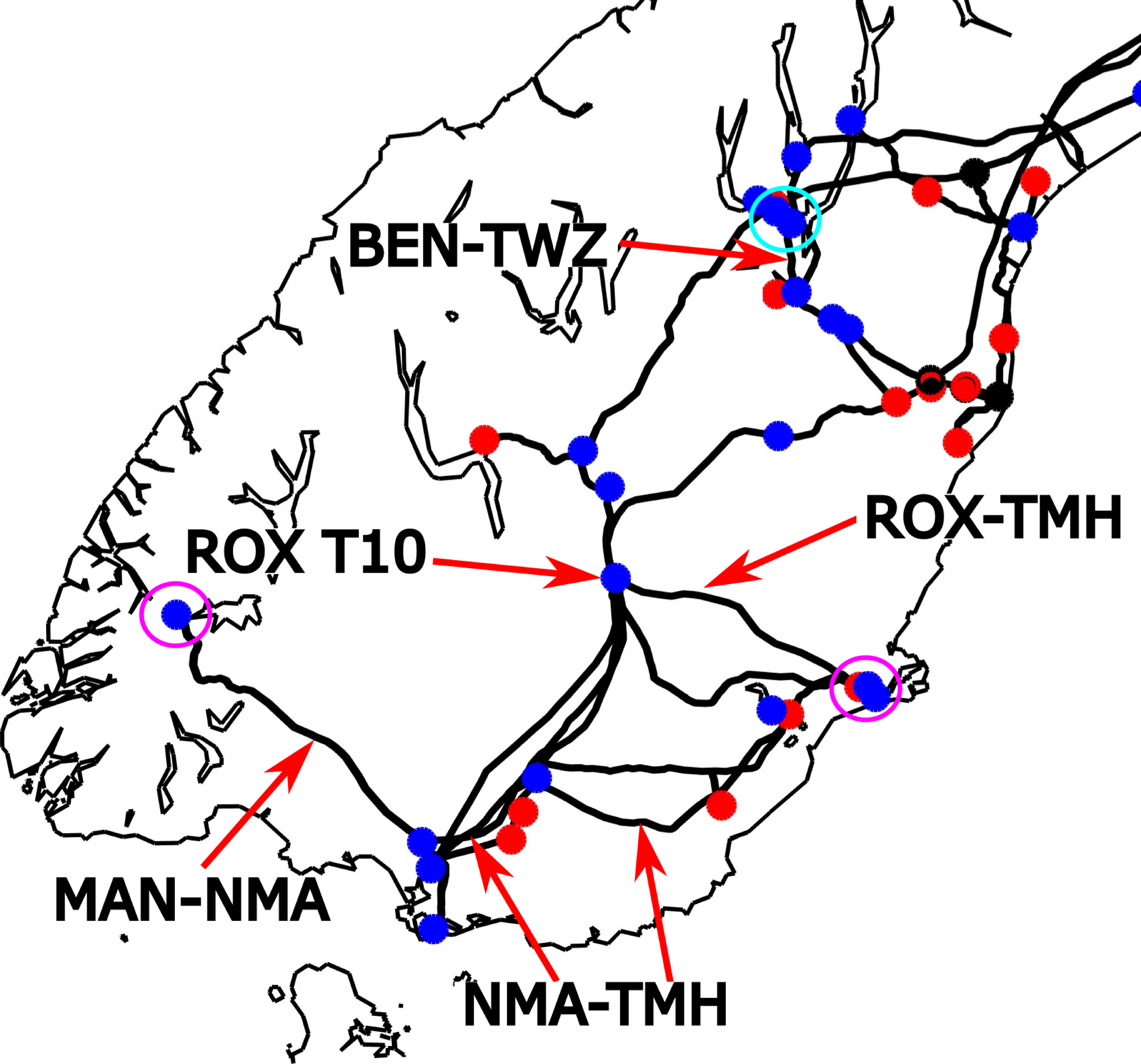
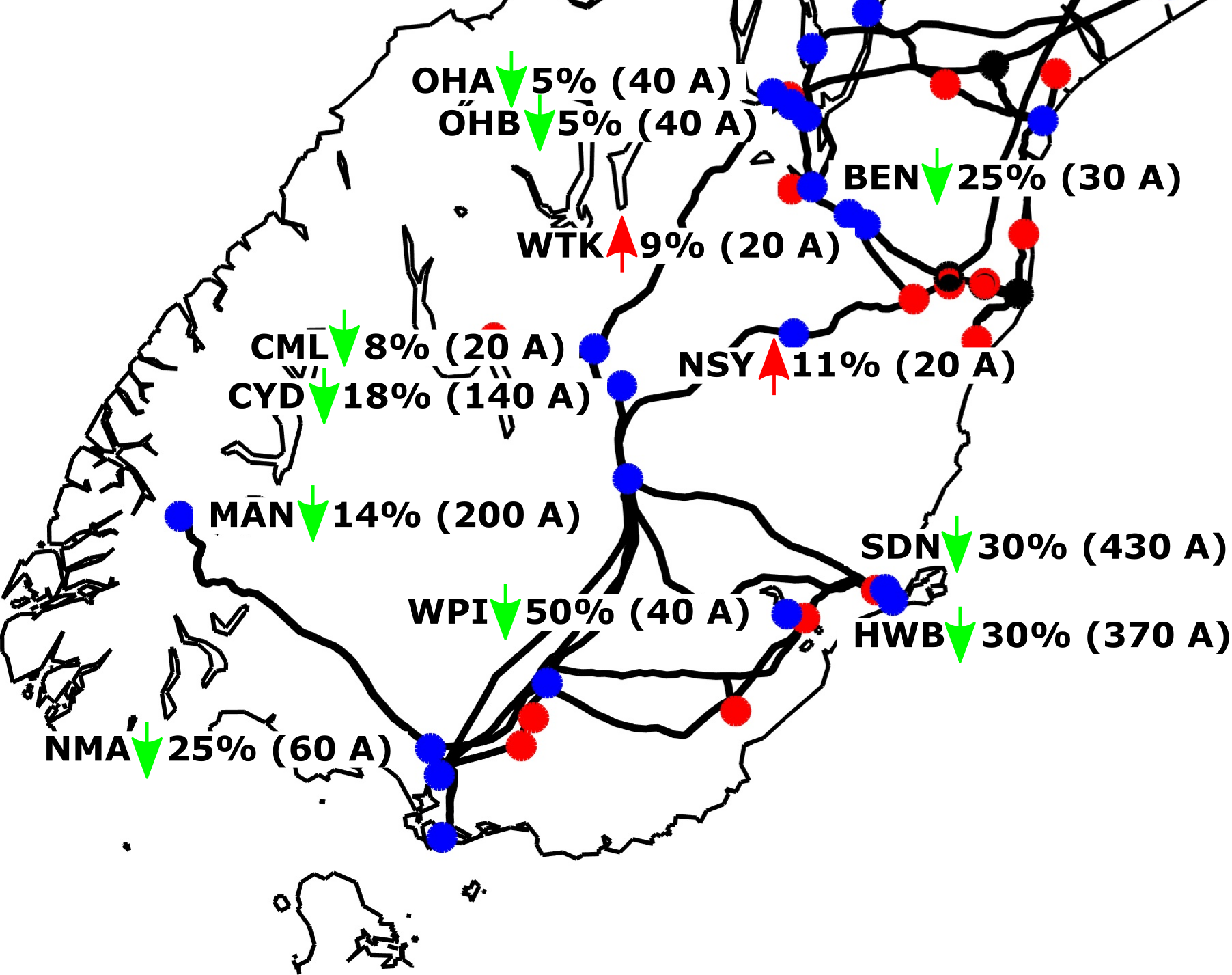

BEN-TWZ
ROX-TMH
ROX T10
MAN-NMA
NMA-TMH

Figure 2.



OHA 5% (40 A)
OHB 5% (40 A)
BEN 25% (30 A)
WTK 9% (20 A)
CML 8% (20 A)
NSY 11% (20 A)
CYD 18% (140 A)
MAN 14% (200 A)
SDN 30% (430 A)
WPI 50% (40 A)
HWB 30% (370 A)
NMA 25% (60 A)

Figure 3.

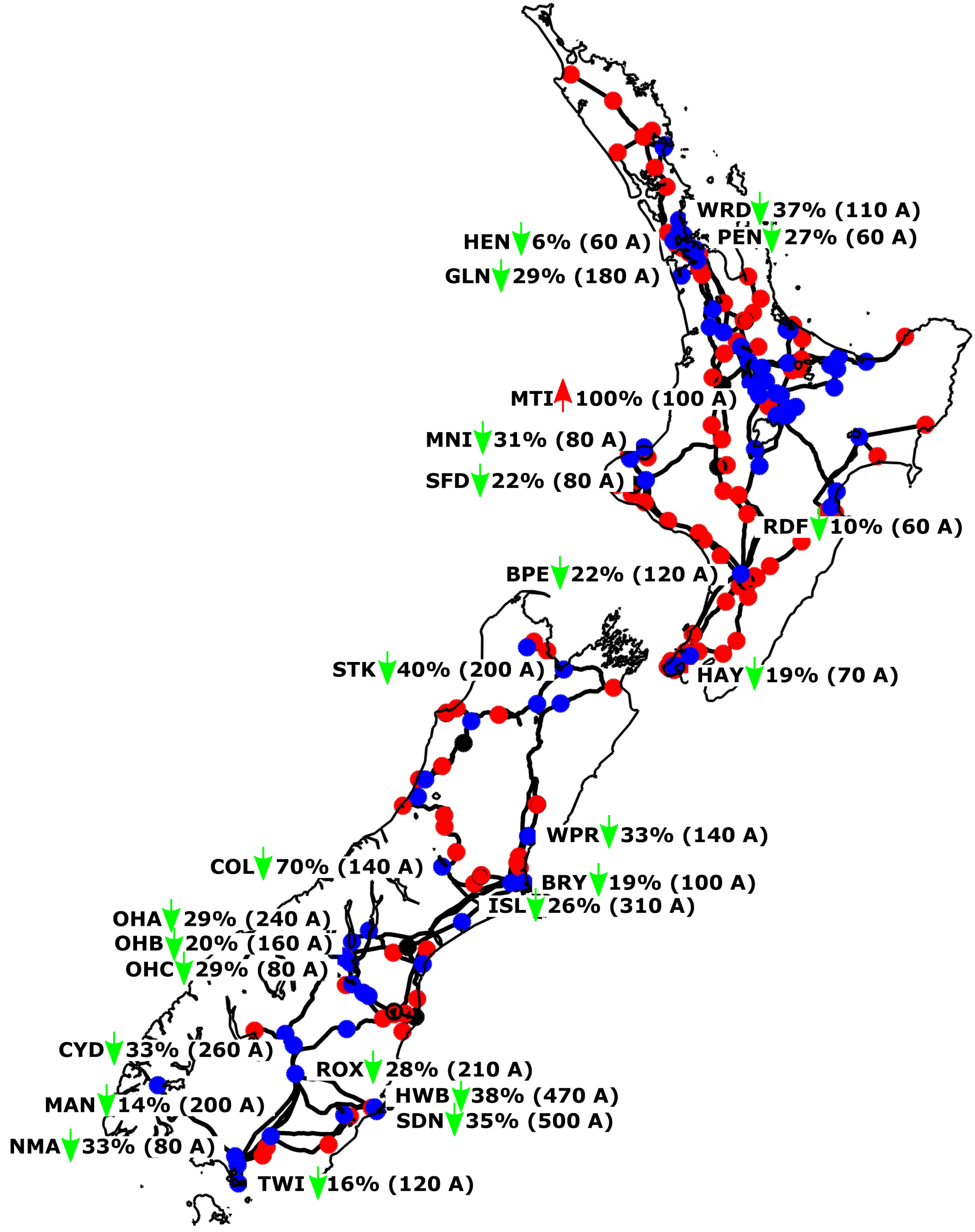

WRD 37% (110 A)
HEN 6% (60 A)
PEN 27% (60 A)
GLN 29% (180 A)
MTI 100% (100 A)
MNI 31% (80 A)
SFD 22% (80 A)
RDF 10% (60 A)
BPE 22% (120 A)
STK 40% (200 A)
HAY 19% (70 A)
WPR 33% (140 A)
COL 70% (140 A)
BRY 19% (100 A)
ISL 26% (310 A)
OHA 29% (240 A)
OHB 20% (160 A)
OHC 29% (80 A)
CYD 33% (260 A)
ROX 28% (210 A)
HWB 38% (470 A)
MAN 14% (200 A)
SDN 35% (500 A)
NMA 33% (80 A)
TWI 16% (120 A)

Figure 4.

DRLNZ
No mitigation
Danger 1
Danger 2
Danger 3
Danger 4
Danger 5
Danger 1
Danger 2
Danger 3
Danger 4
Danger 5
# of Transformers at Danger Levels
120
100
80
60
40
20
0
1989 ROGERS
1989 NERC
1989 EYR
2003 ROGERS
2003 NERC
2003 EYR
2017 ROGERS
2017 NERC
2017 EYR
Extreme Storm Scenario

Figure 5.

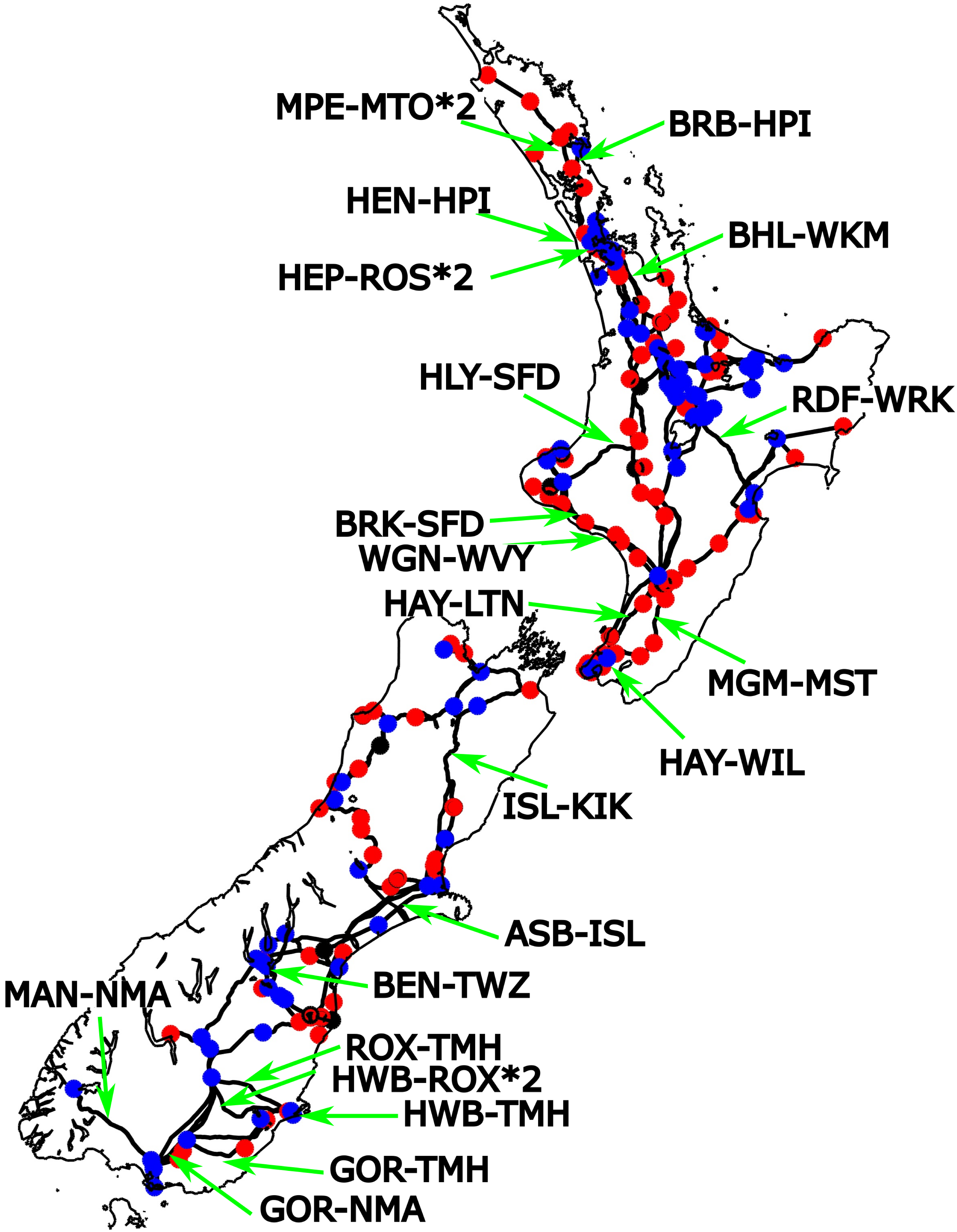
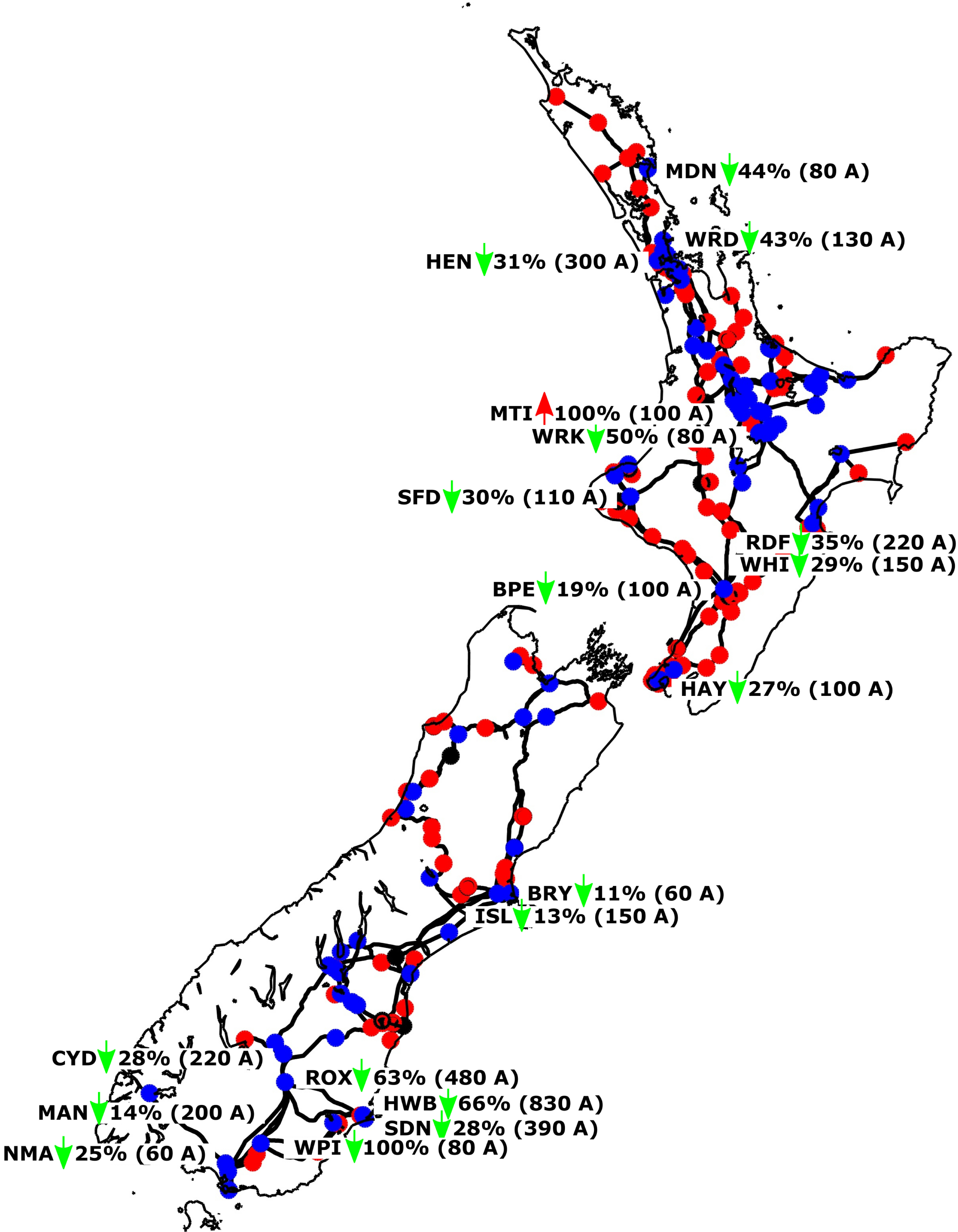

MPE-MTO*2
BRB-HPI
HEN-HPI
BHL-WKM
HEP-ROS*2
HLY-SFD
RDF-WRK
BRK-SFD
WGN-WVY
HAY-LTN
MGM-MST
HAY-WIL
ISL-KIK
ASB-ISL
BEN-TWZ
MAN-NMA
ROX-TMH
HWB-ROX*2
HWB-TMH
GOR-TMH
GOR-NMA

Figure 6.



MDN 44% (80 A)
WRD 43% (130 A)
HEN 31% (300 A)
MTI 100% (100 A)
WRK 50% (80 A)
SFD 30% (110 A)
RDF 35% (220 A)
WHI 29% (150 A)
BPE 19% (100 A)
HAY 27% (100 A)
BRY 11% (60 A)
ISL 13% (150 A)
CYD 28% (220 A)
ROX 63% (480 A)
HWB 66% (830 A)
MAN 14% (200 A)
SDN 28% (390 A)
WPI 100% (80 A)
NMA 25% (60 A)

Figure 7.

TP2022NZ
No mitigation
Danger 1
Danger 2
Danger 3
Danger 4
Danger 5
Danger 1
Danger 2
Danger 3
Danger 4
Danger 5
# of Transformers at Danger Levels
0
20
40
60
80
100
120
1989 ROGERS
1989 NERC
1989 EYR
2003 ROGERS
2003 NERC
2003 EYR
2017 ROGERS
2017 NERC
2017 EYR
Extreme Storm Scenario

Figure 8.

Blockers
TP2022NZ
Danger 1
Danger 2
Danger 3
Danger 4
Danger 5
# of Transformers at Danger Levels
0
10
20
30
40
50
60
70
80
90
100
1989 ROGERS
1989 NERC
1989 EYR
2003 ROGERS
2003 NERC
2003 EYR
2017 ROGERS
2017 NERC
2017 EYR
Extreme Storm Scenario

Figure 9.


October 2003 ROGERS extreme storm scenario
Maximum transformer GIC
GIC [A]
2500
2000
1500
1000
500
0
0
50
100
150
200
250
300
Sum of GICs in Power Network
GIC [A]
25000
20000
15000
10000
5000
0
0
50
100
150
200
250
300
Transformers with Capacitor Blockers

Figure 10.


Maximum transformer GIC [%]
1989 ROGERS GIC
1989 NERC GIC
1989 EYR GIC
2003 ROGERS GIC
2003 NERC GIC
2003 EYR GIC
2017 ROGERS GIC
2017 NERC GIC
2017 EYR GIC
Sum of GICs in Power Network [%]
Transformers with Capacitor Blockers