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EXPANDED SCOPE FINAL REPORT

High tripping rates in solar PV systems >30 kVA

Maximising Solar ROI: Advanced diagnostics for PV systems



Expanded scope final report

Research Theme NT6: Maximising Solar ROI: Advanced Diagnostics for PV Systems
High Tripping Rates in Solar PV Systems >30 kVA

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The authors of this report would like to respectfully acknowledge the Traditional Owners of the ancestral lands throughout Australia and their connection to land, sea and community. We recognise their continuing connection to the land, waters, and culture and pay our respects to them, their cultures and to their Elders past, present, and emerging.

What is RACE for 2030?

[RACE for 2030](#) is a 10-year cooperative research centre (CRC) with \$350 million of resources to fund and support research towards a reliable, affordable, and clean energy future.

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Definitions and abbreviations

Definitions

Term	Definition
Kernel Density Estimate (KDE)	Non-parametric method for estimating the probability density function of a dataset.
Logistic regression	A statistical method used to model the probability of a binary outcome (yes/no, success/failure, 1/0) based on one or more independent variables.
Minimum system load (MSL)	Periods when electricity demand drops so low. Often due to very high levels of rooftop solar generation in mild, sunny conditions, that grid security may be compromised. In such scenarios, there's insufficient demand to maintain secure system operation, despite abundant supply from distributed energy resources such as solar PV and batteries
Interface protection device (IPD) – Also known as central protection device (CPD) or grid protection system	An external, fail-safe layer of protection installed between the PV inverters and the grid. It serves as a backup to the inverters' internal protection mechanisms and ensures the PV system disconnects from the grid under fault conditions.

Abbreviations

Abbreviation	Term
AC	Alternating Current
AEMO	Australian Energy Market Operator
AEST	Australian Eastern Standard Time
API	Application Programming Interface
CPD	Central Protection Device
DPV	Distributed Photovoltaic [generation]
DST	Daylight Saving Time
JSON	JavaScript Object Notation
KDE	Kernel Density Estimate
kV	Kilovolt/s
kVA	Kilovolt-ampere/s
kW	Kilowatt/s
kWh	Kilowatt-hour
LR χ^2	Likelihood-Ratio Chi-Squared Statistic
LR p-value	Likelihood-Ratio Test p-value
MSL	Minimum System Load
NEM	National Electricity Market
NER	National Electricity Rules
NTP	Network Time Protocol
OEM	Original Equipment Manufacturer
p.u.	Per Unit
PMU	Phasor Measurement Unit
pseudo-R ²	Pseudo-R-squared
REST	Representational State Transfer
ROCOF	Rate of Change of Frequency
IPD	Interface protection device
χ^2	Chi-squared statistic

Executive Summary

As distributed energy resources (DER) penetration accelerates across the national energy market (NEM), coincident disconnections of distributed photovoltaic (DPV) during grid-side disturbances have become a material operational risk, especially at minimum load. Commercial-scale arrays (>30 kVA) account for a disproportionate share of potential disconnection risk, relative to their numbers, yet visibility into their protection coordination and event behaviour remains uneven across brands and networks. This report seeks to develop further understanding and identify the cause of increased disconnections of commercial systems by combining fleet-wide five-minute power data with inverter fault logs (where available) to quantify tripping, isolate the dominant drivers, and surface the data gaps that impede cross-vendor learning.

Purpose and scope

This study investigates the frequency, drivers, and geographic patterns of unplanned tripping in DPV systems (or “DPV shake-off”) – Especially >30 kVA commercial and industrial (C&I) assets – across the NEM. Using Diagno Energy’s monitored fleet and relevant power system operating incidents¹, it quantifies tripping during recent transmission-level disturbances, compares performance by size class, brand and settings, and develops actionable measures for operators and standards bodies. The scope integrates 5-minute AC generation data, automated trip detection, geospatial joins, and targeted interrogation of inverter error logs to attribute likely mechanisms. The overarching aim is to reduce disturbance-related PV loss by identifying where interventions (settings, commissioning, data visibility) will yield the greatest benefit.

A persistent challenge is limited, non-standardised visibility for the >30 kVA segment: disparate data feeds, inconsistent timestamps, and fragmented OEM APIs complicate root-cause analysis and hamper targeted interventions—precisely where feeder-level impacts from C&I DPV are largest. Recent standards such as the *Common Smart Inverter Profile - Australia Standard (CSIP-AUS²)*, supported by participating inverter manufacturers, improve baseline visibility and fault reporting for portions of this segment. This study addresses these gaps by marrying power-signal analytics with vendor diagnostics where available.

Key findings

Our event-aligned analysis isolates the main drivers of DPV tripping and quantifies their relative weight, with equipment scale (>30 kVA) emerging as the dominant factor and data visibility/logging gaps limiting cross-vendor attribution. From analysis of an event in Victoria³ (Trip of two 500kV circuits), it was identified that:

- **System size is the dominant risk factor.** In the showcase Victoria event, 39% of >30 kVA systems tripped versus 1 of 60 ≤30 kVA systems (~2%). Logistic regression indicates crossing 30 kVA increases the odds of tripping by ~38–40x.
- **Distance to fault and DNSP membership have weak/limited explanatory power once size is considered.** Large systems tripped both near and far from the disturbance; proximity and DNSP identity added little predictive signal.
- **For systems >30 kVA, the revised AS/NZS4777.2 standard does not necessarily observe better ride-through in the field.** After controlling for size, systems commissioned under AS/NZS 4777.2:2020

¹ AEMO | Power system operating incident reports

² Common Smart Inverter Profile – Australia Standard, <https://www.csipaus.org/>, Accessed: 15/01/2026

³ AEMO, Trip of Moorabool – Sydenham 500kV No.1 and No.2 lines on 13 February 2024. https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2024/final-report---loss-of-moorabool---sydenham-500-kv-lines-on-13-feb-2024.pdf

did not show measurably better performance than 2016-era systems in this dataset; some DNSP–standard combinations (e.g., DNSP 2 2020) exhibited higher trip/fault rates, while DNSP 3 2016 installations rode through more consistently, suggesting commissioning/configuration effects related to the newer Standard.

The development of two methodologies to assess tripping behaviours, identified that:

- **Datasets utilised were incomplete and had limitations:** some site metadata was incomplete and therefore many sites could not support pattern recognition; spatial precision near DNSP boundaries and brand-specific logging gaps introduce uncertainty in certain subgroup analyses, datasets are limited and therefore it is hard to discern between inverter behaviour and other devices upstream
- **5-minute data have limitations in identifying tripping behaviours and needs to be partnered with a secondary method (such as tripping alarms):** Five-minute resolution can miss brief trip/reconnect cycles and therefore may not accurately identify DPV shake-off; partnering this with tripping alarms can help to offer more insight into the event and response.
- **Dual-method detection has the potential to improve confidence and causal insight, particularly given that brief inverter trip–reconnect events may not be fully captured at 5-minute resolution, but more learnings are needed to rely on for event analysis.** Combining the 5-minute power-signal classifier with error-log interrogation (where available) strengthens classification and illuminates voltage-driven mechanisms. However, further work is needed to improve dual-detection methods and their underpinning datasets to reliably use for event disturbance analysis.
- **OEM API fragmentation is a major blocker to cross-vendor learning.** OEM error-flag definitions are not standardised, and fault codes do not necessarily map to equivalent events or categories across manufacturers. Only Inverter Brand 5 yielded complete, timestamped logs suitable for event-aligned forensics; other vendors exhibited limitations in historical depth, access throughput, and timestamp integrity (NTP/DST issues), restricting fault-code statistics to the Inverter Brand 5 fleet.
- **Event coverage and representativeness.** AEMO supplied six major events (Feb 2024–Feb 2025). Large trip counts were concentrated in the Victoria Feb 2024 and NSW Oct 2024 events; several other events yielded few tripped sites, limiting statistical power at the state level.

Next steps for modelling

These findings shift operational and policy priorities toward size-led risk triage, verification and coordination of IPD–inverter protections, and standardised logging/commissioning data so each disturbance yields system-wide learning and measurable trip-rate reduction. The following next steps outline where additional analytical effort will yield improvement in predictive accuracy and event attribution.

- **Risk modelling and operational planning:**
 - Weight feeder risk by installed >30 kVA capacity, not proximity to the transmission fault or DNSP boundary. This aligns prioritisation with the clearest predictor of loss and better targets audits and ride-through checks to the C&I cohort.
 - Embed dual-evidence forensics in post-event reviews: pair power-signal trip flags with inverter/API logs to confirm mechanism (e.g., transient over-voltage followed by outage), improving corrective action plans and vendor feedback loops.
- **Triaging settings matters, and data must come first:**
 - Over Voltage 2 and Sustained Over Voltage settings were more common among tripped sites, but the sample was too small to establish causality, and counterexamples were present. Before settings-based triage can be reliably actioned, IPD make/model and full setpoints (OV/UV/Vector Shift/ROCOF/delays) must be captured in connection and commissioning records and made queryable for post-event forensics.
- **Evidence base (short-cycle research):**
 - Broaden event sampling (add DNSP-level faults and more NEM regions) to improve regional targeting and statistical robustness; deep-dive IPD coordination to identify robust, low-trip configurations for C&I PV.

Recommendations for policy

Translating these analytical insights into durable, system-wide improvement requires changes to standards, commissioning practices, and data infrastructure. The following recommendations target the structural enablers that will reduce disturbance-related DPV loss across the NEM.

- **Standards, commissioning and compliance:**
 - Close the “paper-compliance vs performance” gap. Expand compliance verification to include field-proven IPD/inverter coordination checks and commissioning records that capture full setpoints and delays. This addresses the observed lack of performance uplift under newer standards in the present dataset.
- **Data and visibility (industry-wide enablers):**
 - Standardise inverter fault logging across brands (authorisation models, minimum retention, time-zone/timestamp format, harmonised fault dictionary, baseline rate limits) and enforce NTP-consistent clocks to enable event-aligned analytics across fleets. Embed these requirements in AS/NZS 4777 revisions and/or DNSP connection agreements.
 - Capture and store IPD make and model information and improve the completeness and accuracy of settings data in connection/commissioning databases to make post-event forensics faster and more reliable.
 - In the near term, the *Common Smart Inverter Profile - Australia Standard* (CSIP-AUS⁴), offers the most direct pathway to standardised logging, as it already mandates logging capabilities. However, further work by the DER Integration API Technical Working Group (DERIAPITWG) is needed to define the required detail and develop standard test cases.
- **Bottom line for decision-makers:**
 - Per site, >30 kVA systems are the highest-value target for intervention. In this event they tripped at roughly 39% versus about 2% for ≤30 kVA systems, reflecting where targeted effort is most cost-effective. Each such system carries both a higher trip probability and more capacity at risk, so a settings review or commissioning check there averts more expected disconnection than the same effort on a small system. The emphasis is on return per intervention rather than absolute share, since the large ≤30 kVA base still contribute to total shed. In the longer term standardised fault logging, and richer commissioning records can turn each disturbance into high-value learning across brands and networks.

⁴ Common Smart Inverter Profile – Australia Standard, <https://www.csipaus.org/>, Accessed: 15/01/2026

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1 Introduction

The Australian Energy Market Operator (AEMO) has identified challenges with relation to the behaviour of distributed photovoltaic (DPV) systems connected within the distribution network, in response to power system events particularly in the context of compliance and visibility. Rooftop and commercial PV now contribute a significant proportion of generation in the National Electricity Market (NEM), with systems present in approximately one-third of detached homes and a rapidly growing share of commercial and industrial installations.⁵

AEMO has identified that distributed PV can “shake off”, in response to a transmission level disturbance, increasing contingency sizes and threatening system security.⁶ The 2020 Revision of AS/NZS4777.2 sought to address this risk, and strengthen DPV ride-through performance, however compliance challenges have been observed. The focus of this work is to continue to enhance the understanding of DPV behaviours and compliance.

1.1 Background

AEMO has undertaken a number of reviews on DER Behaviours during disturbances. These investigations have highlighted that:^{7, 8, 9}

- AEMO identified that there is considerable disconnection of DPV in response to voltage disturbance, increasing contingency and impacting the market. To resolve this disconnection, proposed changes to the AS/NZS4777.2 Inverter Standard to help improve the ride-through capability of DPV (and DER more generally). These were integrated and published as part of the AS/NZS4777.2:2020 Standard version.
- Following the introduction and implementation of AS/NZS4777.2:2020, data from a range of in-field data sources identified that in early 2023, less than half of new systems installed were set correctly to the Standard.
- Following substantial engagement with industry to improve compliance, data from various sources indicate that compliance in early 2024 has since improved to 80-90%. This was largely attributed to voluntary OEM actions to improve the commissioning menu.
- Installation compliance, data visibility during these events, and clear governance roles are critical in ensuring the desired DPV behaviours, specifically its ride-through response.
- Despite the improvements to the inverter Standard to improve ride-through behaviours, there continues to be a high rate of tripping for systems >30kVA, in some events this can be up to 20 times greater.

The concern regarding the high incidence of tripping events in distributed PV systems >30 kVA is the lack of visibility to understand the cause of the greater rate of disconnection. Elements that may impact DPV tripping are multi-factorial and may include:

- Grid disturbances such as voltage dips, frequency events, or phase angle jumps.

⁵ AEMO, [Learnings from industry implementation of emergency backstop mechanisms for distributed resources – Q2 2025](#), July 2025.

⁶ AEMO, [Final Report – Trip of Moorabool – Sydenham 500 kV No. 1 and No. 2 lines on 13 February 2024](#), July 2025

⁷ AEMO, [Compliance of Distributed Energy Resources with Technical Settings](#), April 2023

⁸ AEMO, [Compliance of Distributed Energy Resources with Technical Settings: Update](#), December 2023

⁹ AEMO, [Compliance of Distributed Energy Resources with Technical Settings: 2025 Update](#), August 2025

- Inverter protection settings (including firmware), including compliance to relevant ride-through capability defined in the standards (e.g., AS/NZS 4777.2:2024).¹⁰
- Interface protection device (IPD) which was previously required of systems >30kVA size (however revised to >200kVA in the AS/NZS4777.1:2024 Standard), and their configurations and settings.
- Interactions between multiple inverters or between inverter controls and network protection.
- Local network conditions such as feeder congestion or reverse power flows.

The lack of standardised, high-resolution operational data from these systems hinders the ability of AEMO and DNSPs to diagnose root causes, identify high-risk locations, and develop targeted interventions. This is particularly problematic in the >30 kVA segment, where installations are often concentrated in commercial and industrial zones and can represent a large proportion of feeder-level generation.

Diagno Energy, through its RACE for 2030 project, has been developing advanced methods to detect inverter tripping and attribute grid-related causes by analysing collocated system behaviour. Building on this capability, the expanded AEMO-focused scope will apply statistical and machine learning techniques to a large dataset of monitored PV systems to quantify tripping rates, identify systemic patterns, and assess the role of key technical and operational parameters.

Understanding the frequency, triggers, and geographic distribution of the response of inverters to events is essential for:

- Improving operational resilience under high-DER conditions.
- Supporting the design and implementation of immediate rectification actions to address and reduce DPV tripping.
- Informing regulatory compliance monitoring and inverter standards enforcement and scope.

AEMO has emphasised the need for improved data-sharing and coordination between industry, governments, OEMs, and network service providers to address these risks and maintain a secure, reliable NEM as the energy transition accelerates.

1.2 Diagno Monitoring

Diagno is a monitoring and analytics platform for distributed photovoltaic (DPV) systems, providing time-series operational data and diagnostic insights across a diverse fleet of residential and commercial installations. Diagno integrates primarily with inverter APIs, and where available with power meters and third-party monitoring devices, to collect system-level and inverter-level performance data. These data streams are complemented with site metadata (e.g. geographic location, installed capacity, tilt and azimuth) and local weather data to support performance assessment and fault detection.

Data captured by Diagno include historical AC generation time series at 5-minute resolution, alongside associated system metadata such as inverter brand, system size, and site location. For this study, the 5-minute AC generation data were used to identify instances where inverter output dropped to zero and subsequently recovered, consistent with inverter tripping behaviour. Timestamped generation data, combined with site location information, enabled temporal alignment with transmission disturbance events and spatial analysis relative to affected network assets.

Where available, Diagno also accesses inverter fault and status logs via OEM APIs, providing additional diagnostic context (e.g. grid overvoltage or protection-related events). These logs were used in this study to

¹⁰ Standards Australia, [Grid connection of energy systems via inverters, Part 2: Inverter requirements](#), August 2023.

support and cross-validate generation-based trip detection, subject to vendor-specific data availability and retention constraints described later in the report.

Diagno maintains historical records of monitored systems, enabling retrospective analysis of past events where data pipelines were active at the time of occurrence. As of 11 April 2025, the Diagno database contained records for more than 2,000 DPV sites across multiple Australian jurisdictions.

1.3 Study objectives and overview

The primary objective of this study is to investigate the frequency, drivers, and geographic patterns of unplanned tripping in large-scale distributed PV systems (>30 kVA) across the NEM. Using Diagno Energy's established detection methodologies and extensive monitored fleet, the study will:

- **Quantify tripping incidence** under normal operating conditions and during AEMO-identified transmission-level power system events.
- **Identify technical, operational, and locational factors** most strongly correlated with tripping, including inverter and IPD device characteristics, protection settings, installation age, and local network conditions.
- **Compare performance** of larger (>30 kVA) systems with smaller (\leq 30 kVA) systems in ride-through capability during disturbances.
- **Assess event-specific behaviour** across different DNSPs, zones, and system configurations during a sample of recent NEM disturbances.
- **Develop actionable recommendations** to reduce tripping risk, enhance visibility, and inform regulatory and operational frameworks, including potential integration with broader DER orchestration and emergency backstop strategies.

This work builds on the RACE for 2030 research program, ensuring efficiency and leveraging co-funding opportunities while aligning market operator priorities with industry-led data analysis.

1.4 Scope - Inclusions

This document aims to:

- Analysis of >30 kVA PV systems using Diagno Energy's monitored fleet across all NEM jurisdictions, with a confirmed dataset of over 2,000 systems.
- Comparative assessment of \leq 30 kVA and >30 kVA systems' ride-through performance during grid disturbances.
- Use of high-resolution (5-minute) inverter and power meter data, including AC/DC electrical parameters, inverter temperature, error codes, and IPD settings where available.
- Identification and classification of tripping events, including zero and non-zero tripping.
- Statistical correlation analysis of tripping incidence with factors such as inverter/IPD make and model, relay configurations, system size, installation date, DNSP boundaries, feeder-level constraints, and geographic location.
- Detailed evaluation of fleet behaviour during one AEMO-nominated NEM-wide system event, with tripping behaviour correlated to technical and geographic parameters.
- Geospatial and DNSP-specific reporting to identify high-tripping zones and systemic issues.
- Recommendations for regulatory, operational, and technical measures to reduce tripping rates and improve >30 kVA PV system visibility.

The key questions addressed in this document include:

- What is the frequency and nature of tripping events in large-scale commercial PV systems (>30 kVA) across the NEM?

- How do tripping rates in >30 kVA systems compare to smaller systems (≤ 30 kVA) during grid disturbances?
- Which technical factors (e.g., inverter make/model, IPD device type and settings, system configuration) are most strongly correlated with tripping events?
- What geographic, DNSP, or feeder-level patterns can be identified in tripping behaviour?
- How do >30 kVA systems respond during specific AEMO-identified transmission-level power system events, and what causes can be attributed to these behaviours?
- Can tripping causality be reliably validated by comparing collocated systems and cross-referencing inverter/IPD settings with observed performance?
- What are the limitations of current visibility for >30 kVA PV systems, and how might these be addressed through regulatory or operational improvements?
- What recommendations can be made to reduce high tripping rates and improve system resilience during power system disturbances?

1.5 Scope - Exclusions

The following are not covered in this document:

- Real-time operational monitoring or live event response. All analyses will be conducted on historical datasets.
- Physical site inspections, equipment testing, or hardware modifications.
- Development or enforcement of new inverter/IPD standards (recommendations only will be provided).
- Detailed economic modelling of mitigation measures (economic implications may be noted qualitatively where relevant).
- Analysis of PV systems outside the Diagno Energy monitored fleet, except where limited public or partner datasets are used for validation.
- In-depth investigation of rooftop PV ≤ 30 kVA outside the comparative ride-through assessment.

2 Methodology

The methodology for this study was designed to comprehensively assess tripping behaviour in distributed solar PV systems during grid-side fault events, with a particular focus on systems rated above 30 kVA. The approach integrates AC generation data (at 5-minute resolution), automated fault detection, geospatial data processing, and statistical analysis to identify and interpret system responses during and after network disturbances.

A central element of this process was the Diagno fault detection engine, which enabled efficient and systematic identification of inverter tripping events across the monitored fleet. Inverter metadata – including equipment specifications, system configuration, and spatial context – was extracted, cross-checked, and enriched using spatial datasets. This enabled targeted analysis of tripping patterns as a function of equipment type and proximity to fault locations.

For each grid event, inverter responses were detected at the state level (i.e., the state in which the event occurred). The complete data processing and analysis workflow – from event detection and data acquisition through to feature engineering and tripping identification – is illustrated in Figure 1.

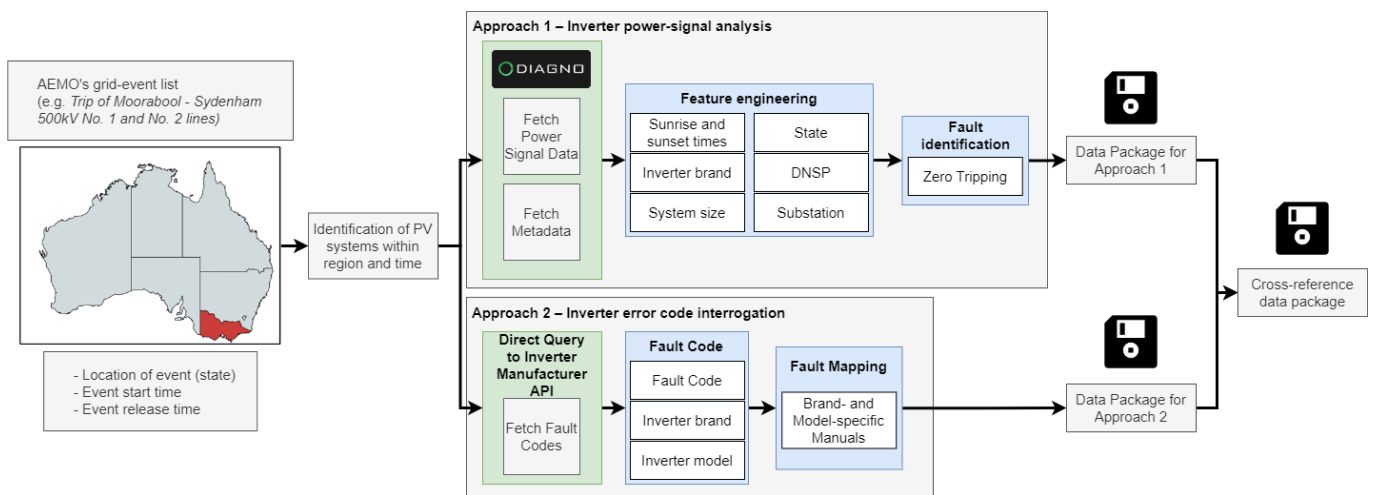


Figure 1. Schematic overview of the analysis pipeline for the inverter response to a grid event.

The study used a dual-path methodology to characterise PV system behaviour:

- **Approach 1 - Inverter power-signal analysis:** Using 5-minute AC generation data, the Diagno engine flagged sudden generation drops indicative of tripping.
- **Approach 2 - Inverter error-code interrogation:** Using inverter vendor APIs, timestamped fault logs were retrieved and harmonised into a consistent set of diagnostic categories using brand- and model-specific manuals.

By combining generation data with inverter diagnostics, this approach captured both the occurrence of tripping and the root cause signatures across equipment classes, installation standards, and network locations, particularly for the >30 kVA systems that are the primary focus of this work.

2.1 Approach 1 - Inverter power-signal analysis

This approach quantifies how DPV systems respond to grid-side disturbances by analysing historical measured AC generation data at 5-minute resolution for every monitored inverter in the affected state. The workflow follows the steps outlined below and illustrated in Figure 2.

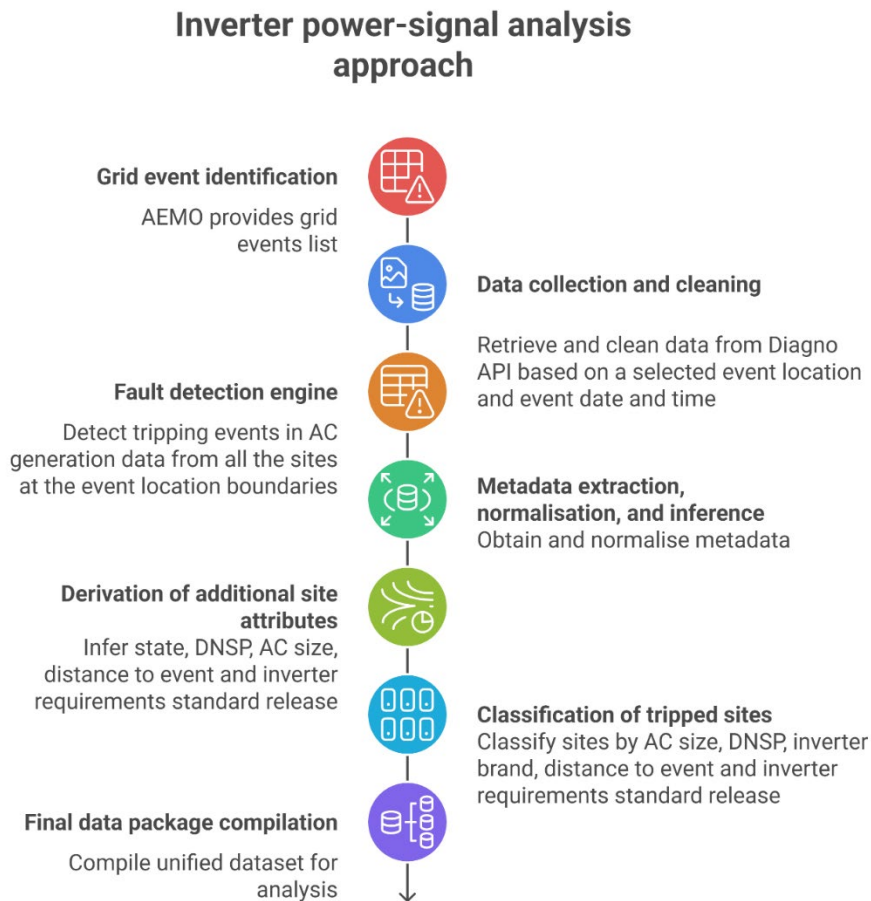


Figure 2. Analysing DPV systems' response to grid disturbances using power-signal analysis approach.

Step 1: Grid event identification

AEMO provided a list of events, with each event document containing:

- Identification of a major power system event (e.g., tripping of a transmission line) selected for investigation based on AEMO reporting.
- Extraction of key event information, including:
- Location of the event at the state level (e.g., Victoria).
- The asset where the event occurred (e.g., transmission line, power substation, transmission substation).
- Event date and time window (start and end).

Step 2: Data collection and cleaning

Using the event location (state) and time window, data was retrieved from the Diagno API as follows:

- Query the Diagno API to retrieve all monitored site IDs and monitor IDs within the event region.
- Filter for monitors active during the event window.
- Retrieve 5-minute interval AC generation data for each monitor covering the event duration.
- Align timestamps with market time and adjust for sunrise/sunset to exclude non-daylight hours.

Step 3: Fault detection engine

Diagno's automated fault detection algorithm was applied to cleaned 5-minute AC generation data for each monitor. This algorithm detects potential tripping events by identifying periods of zero AC generation during daylight hours that immediately follow normal generation. The detection process involved:

- Checking each 5-minute interval for zero generation, representing a complete loss of AC power.
- Classifying monitors and sites exhibiting signs of tripping.
- Labelling monitors with missing AC generation data for distinction from confirmed tripping cases.
- Compiling a list of sites and monitors showing zero generation, including site ID, monitor ID, tripping time(s), and tripping duration(s).

Step 4: Metadata extraction, normalisation and inference

For each monitor from Step 3, the Diagno API was queried to obtain metadata, including:

- AC and DC system sizes.
- Inverter brand.
- Geographical coordinates (latitude, longitude).
- Installation date.
- Commissioning documents, where available.

The API response returns a list of all inverters that experienced a tripping event. Each inverter is associated with a specific site, and many sites contain multiple inverters monitored by one or more site-level monitors. Analysis was performed at the monitor level. If any monitor associated with a site exhibited a tripping event, the site was flagged as having experienced an event. For analytical purposes, all inverters at a flagged site were aggregated to the site level to represent the total installed system capacity, noting that this aggregation is used for sizing and impact assessment rather than to imply that tripping necessarily originated upstream of the inverters.

Step 5: Derivation of additional site attributes

While the metadata contained basic location and size information, additional attributes were inferred to enable further analysis, including:

- **State:** Confirmed via spatial overlay with Australian state polygons (Digital Atlas Australia)¹¹ to ensure site coordinates matched the designated state.
- **DNSP:** Assigned using spatial joins with DNSP boundaries from the National Opportunity Maps.¹² This approach provides an unambiguous DNSP assignment at the site level while maintaining compliance with data privacy requirements.
- **Distance to event:** Calculated as the shortest distance from the site to the affected grid asset, using coordinates from Geoscience Australia.¹³
- **AC system size:** For sites missing inverter size, AC capacity was inferred from DC capacity using a typical DC/AC ratio of 1.3.

Step 6: Classification of tripped sites

Tripped sites were identified based on observed drops in AC generation to zero followed by recovery, using 5-minute resolution data (see Step 3). Because only generation data were available, tripping events could not be definitively attributed to a specific transmission disturbance. Instead, attribution was inferred based on

¹¹ Geoscience Australia, [Land Borders \(Borderlines\) – Digital Atlas Australia](#). Accessed on: 26 June 2025.

¹² ENA, [Network Opportunity Maps – Full GIS “service region” polygons – with data](#), July 2021. Accessed on: 20 June 2025.

¹³ Geoscience Australia, [Electricity Transmission Lines](#). Accessed on: 26 June 2025.

temporal proximity to the provided transmission event timestamp. Statistical analyses were performed to classify tripped sites based on:

- **AC size:** ≤ 30 kVA versus >30 kVA capacity bands.
- **DNISP-level:** Segmentation by DNISP to assess spatial clustering and network-specific patterns.
- **Inverter brand:** Aggregation by manufacturer to detect brand-specific trends.
- **Distance to event:** Calculated as the shortest geodesic distance from each site to the affected transmission line segment, grouped into bins (e.g., 0-20 km, 20-40 km) to assess empirical tripping probability vs distance.
- **Inverter requirements standard release:** Categorised by commissioning under pre-AS/NZS 4777.2:2015, AS/NZS 4777.1:2016, AS/NZS 4777.2:2020, AS/NZS 4777.2:2024 or AS/NZS 4777.1:2024, to assess standard effectiveness.

To test hypotheses on tripping factors, logistic regression models were applied to estimate the probability of tripping as a function of distance from the fault, stratified by system size. Coefficients and confidence intervals quantified risk gradients. A significance threshold of $p < 0.05$ was used, with small sample results supplemented by visual/descriptive summaries.

Step 7: Final data package compilation

Following classification and analysis, a consolidated dataset was produced containing:

- **System-level attributes:** Capacity class, inverter brand, commissioning standard version, DNISP, and geolocation.
- **Event records:** Tripping status, event date/time, fault location, and calculated distance to event.
- **Derived metrics:** Logistic regression outputs, classification results, and spatial clustering indicators.

This unified dataset forms the foundation for statistical and spatial analyses, such as correlation studies by inverter brand or system size and geospatial mapping of tripping patterns by DNISP and distance to disturbance. It also supports report visualisations and DNISP-level summaries.

2.2 Approach 2 - Inverter error code interrogation

Inverter-side diagnostics that may not appear as a complete power drop was captured through querying the proprietary monitoring APIs of every one of the five inverter brands present in the study cohort. For each active inverter during an event, a targeted request was submitted to the vendor's API endpoint to retrieve all error or warning messages recorded during the disturbance and within a 10-minute buffer period afterward. This time window was selected to ensure inclusion of delayed or post-disturbance fault responses that might not coincide exactly with the event timestamp. The workflow for inverter error code interrogation is illustrated in Figure 3.

This approach provided insight into disturbance impacts that might not have been visible through power-signal analysis of 5-minute readings alone, such as transient voltage excursions, frequency deviations, or manufacturer-specific ride-through failures. The process comprised the following steps:

Step 1: Grid event identification

AEMO provided a list of major power system events, similar to that listed mentioned in step 1 in approach 1. For each event, the below data was extracted:

- Location (state level, e.g., Victoria).
- Asset affected (e.g., transmission line, substation).
- Event date and time window (start and end).

Step 2: Identify inverter population

Diagno metadata was used to compile a list of all inverters (including brand and serial number) active during the event window within the affected state.

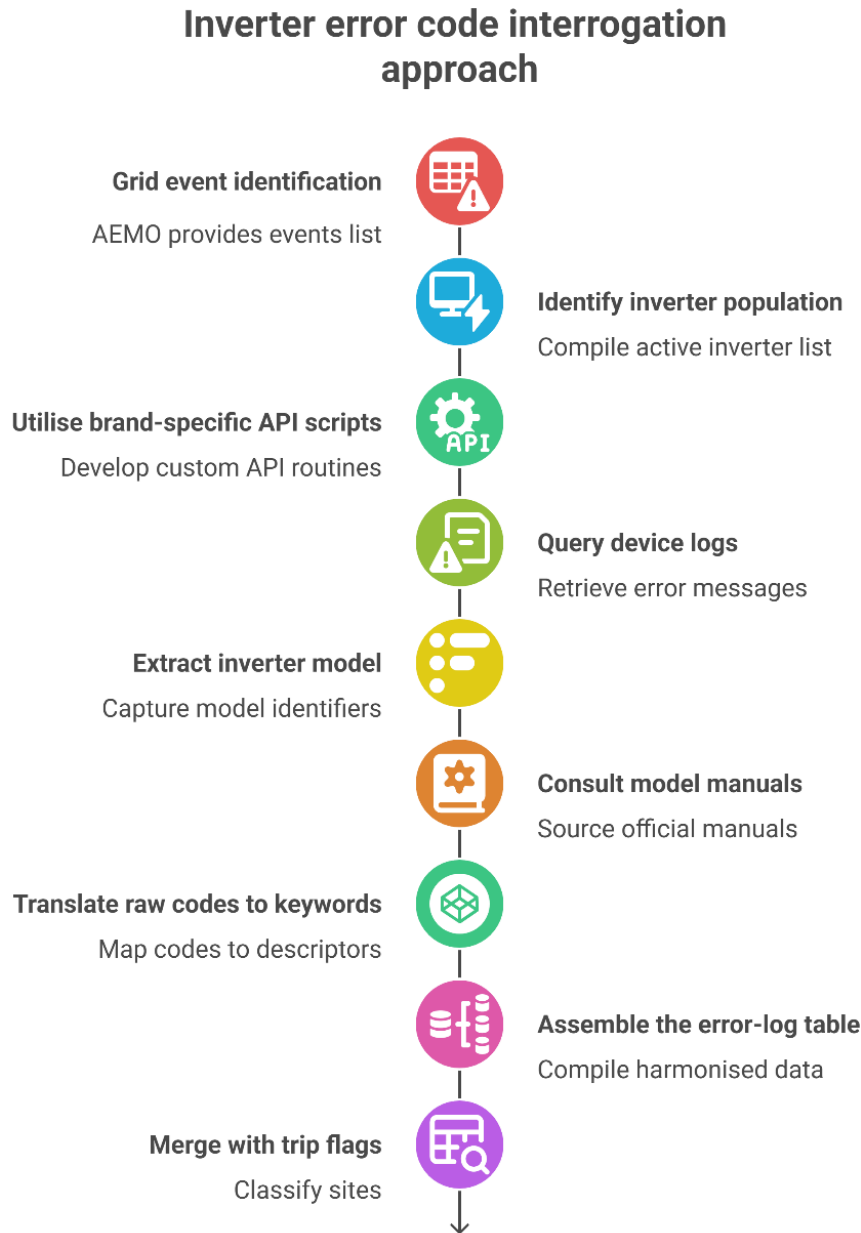


Figure 3. Workflow for inverter error code interrogation, from event identification to merging fault logs with trip flags.

Step 3: Utilise brand-specific API scripts

Custom representational state transfer (REST) API routines were developed for all five inverter brands, following each vendor's authentication protocols and endpoint specifications.

Step 4: Query device logs

For each inverter, a single API request was issued to retrieve all error or warning messages timestamped within timestamp (2 by 5-minutes; ~10 minutes) after the event time and across the entire day of the event. Responses were collected in JSON (JavaScript Object Notation) format.

Step 5: Extract inverter model

The metadata payload was parsed to capture the exact model identifier required for interpreting vendor-specific fault codes.

Step 6: Consult model manuals

Official inverter manuals were sourced from vendor support sites or public repositories and archived for reference.

Step 7: Translate raw codes to keywords

A cross-brand fault dictionary was developed by mapping each numeric or alphanumeric code to a plain-language descriptor. An example of fault-code translation table is shown in Table 1.

Table 1. Example fault-code translation table.

Inverter brand	Inverter model	Raw code	Event context	Keyword
Brand A	Model A	002	The grid voltage is higher than the set protection value	Grid overvoltage
Brand A	Model A	003	The transient grid voltage is higher than the standard value.	Grid transient overvoltage
Brand A	Model A	004	The grid voltage is lower than the set protection value	Grid undervoltage
Brand A	Model A	007	AC output current exceeds the upper limit of the inverter.	AC instantaneous overcurrent
Brand A	Model B	002	The grid voltage is higher than the set protection value	Grid overvoltage
:	:	:	:	:

This harmonisation process enables direct comparison of error events across brands and models, even when vendors use different internal coding schemes.

Step 8: Assemble the error-log table

The processed data were compiled into a harmonised table containing site ID, inverter brand and model, timestamp, raw fault code, and translated keyword.

Step 9: Merge with trip flags

The error-log table was merged with the power-signal dataset, classifying each site into one of four categories:

- Trip + error
- Trip-only
- Error-only
- Neither

All error types returned by the API during the event window were included in the classification with no fault codes excluded prior to analysis. The complete fault dictionary comprises hundreds of unique codes across all models in the study cohort. When filtered for codes logged during the analysed disturbance events, 77 unique fault codes were identified across four *Inverter Brand 5* models, which were further standardised into nine fault-category keywords.

3 DPV sites and grid events

3.1 Diagno DPV sites overview

Diagno’s dataset of monitored DPV systems provides a diverse sample across a range of system sizes and geographic locations. As of 11 April 2025, the database contained details for more than 2,000 sites, distributed by system size and by location as listed in Table 2 and Table 3, respectively. Given the focus of the showcase event analysed in Section 4, Figure 4 shows the geographic distribution of the 165 monitored DPV sites located in Victoria that returned AC generation data on the event day.

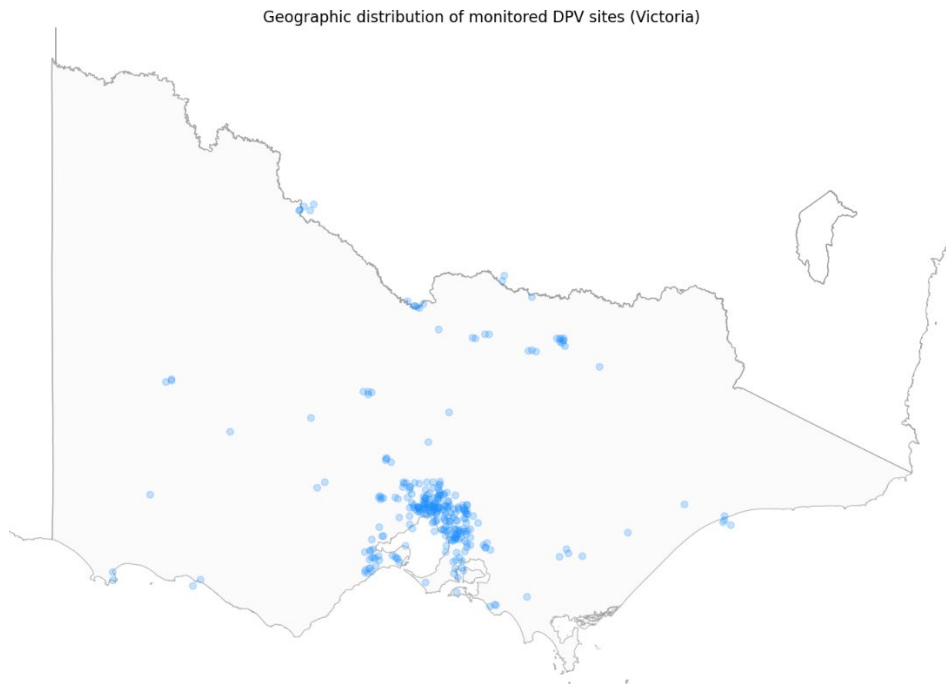


Figure 4. Geographic distribution of monitored distributed photovoltaic (DPV) sites in Victoria. Each point represents the location of a DPV system monitored by the Diagno platform as of April 2025

Table 2. Diagno dataset of DPV systems by system size.

System size	No. of sites
≤30 kW	611
30-200 kW	744
200-500 kW	745
500-5000 kW	47

Table 3. Diagno dataset of DPV systems by location.

Location	No. of sites
NSW	551
WA	373
VIC	296
QLD	183
SA	83
TAS	25
ACT	23

NT	10
Marlborough (New Zealand)	3

3.2 List of AEMO events and high-level analysis

AEMO provided a list of six significant grid-side events that occurred between February 2024 and February 2025, as summarised in Table 4. For each event, the date, time, and state are recorded, along with a brief description of the fault. The geographical scope is limited to the state in which the fault occurred. Most incidents involved high-voltage transmission lines (220-500 kV), often with concurrent trips on multiple circuits.

Table 4. List of grid-side events provided by AEMO

Event #	Date	Time	State	Disconnections observed through 1-min data		Event details
				≤30kV A	>30kVA	
1	13-Feb-24	13:08:48	VIC	8-16%	40%	Trip of Moorabool – Sydenham 500 kV No. 1 and No. 2 lines ¹⁴
2	25-Mar-24	14:12:40	SA	13-18%	40%	Torrens Island 275kV CBs tripped, Torrens island - Lefevre 275kV line trip and auto reclose ¹⁵
3	27-Mar-24	15:29:27	SA	9-12%	40%	Torrens Island CT explosion. Outage of Torrens Island A West 275kV bus and Torrens Island AC3 275kV CB Addendum on DPV and load behaviour: 275 kV current transformer failures in South Australia ¹⁶
4	27-Jul-24	9:51:00	QLD	2%	9%	Goodna 275kV No.2 Busbar and Goodna No.1 Trans ¹⁷
5	19-Sep-24	13:40	TAS	Minimal	40%	Gordon - Chapel Street No. 1 and No. 2 220kV Lines ¹⁸
6	23-Dec-24	16:32:23	SA	8%	39%	Happy Valley - Morphett Vale East 275kV Line Morphett Vale - Cherry Gardens 275kV Line ¹⁹

Site eligibility was confirmed by intersecting each Diagno site’s latitude-longitude coordinates with state borders from Digital Atlas Australia shapefiles.¹¹ For each event, the corresponding site IDs and monitor IDs were compiled based on the relevant state. The AC generation data and available error logs were then retrieved via the Diagno API for the event date and time.

- **Approach 1 – Inverter power-signal analysis:** The 5-minute AC-generation records for every inverter in the affected state were processed using the Diagno fault-detection algorithm to flag tripping events. An inverter was classified as having tripped if its AC generation dropped to zero in either of the two 5-minute intervals immediately following the market-time stamp of the disturbance.

¹⁴ AEMO, Preliminary Report – Trip of Moorabool – Sydenham 500 kV No. 1 and No. 2 lines on 13 February 2024, February 2024.

¹⁵ AEMO, 275 kV current transformer failures in South Australia 14-27 March 2024, September 2024.

¹⁶ AEMO, Addendum on DPV and load behaviour: 275 kV current transformer failures in South Australia 14-27 March 2024, October 2024.

¹⁷ AEMO, Trip of Goodna 275 kV No. 2 Busbar and Goodna 275/110 kV No. 1 Transformer on 27 July 2024, January 2025.

¹⁸ AEMO, Trip of Gordon – Chapel Street No. 1 and No. 2 220 kV Lines on 19 September 2024, February 2025.

¹⁹ AEMO, Trip of Happy Valley – Morphett Vale East 275 kV line and Cherry Gardens – Morphett Vale East 275 kV line on 23 December 2024, May 2025.

- **Approach 2 – Inverter error-code interrogation:** Error logs were collected for the two consecutive 5-minute intervals (approximately 10 minutes in total) immediately following the event timestamp, as well as across the entire day of the event. While API scripts were developed for all five available inverter brands, only the *Inverter Brand 5* interface consistently returned timestamped logs during the study period. Other vendors experienced authentication failures, limited historical data access, or nondeterministic status messages rather than clear fault-log codes. These limitations are detailed in Section 5.2.2.
- By combining **Approach 1 (inverter power-signal analysis)** with **Approach 2 (inverter error code interrogation)**, the dataset captures both visible generation drops and latent fault conditions. This dual-method approach improves classification accuracy, helps identify brand- or model-specific weaknesses, and provides a more comprehensive understanding of disturbance ride-through performance.

3.3 Data completeness and limitations

A summary of the monitored assets contributing usable data for each event is presented in Table 5. “Unique sites” refers to the total Diagno fleet in the relevant state as of 4 July 2025. “Sites with generation data” are those that successfully returned time-series AC generation data on the event day. Sites were not required to have complete coverage for all timestamps on that day. Inclusion reflects whether a site was actively onboarded and returning data at the time of the event. Differences between the total number of *unique sites* and *sites with generation data* primarily reflect sites that were onboarded to Diagno after the event date and therefore did not have historical data available for that event. Moreover, “inverters with generation data” expands that count to individual inverters that successfully returned time-series AC generation data in each site. “Sites with error code logs” and “Inverters with error code logs” (Inverter Brand 5 only) capture site and inverters that were able to successfully extract fault log data, respectively. Tripped sites are defined as locations where at least one inverter exhibited either (i) a complete drop in AC generation to zero within the two 5-minute intervals immediately following the event timestamp (Approach 1), or (ii) a relevant, event-consistent fault log entry (e.g. grid overvoltage) recorded within the same post-event intervals (Approach 2)

A further limitation arises from the 5-minute resolution of AC generation data. Inverters that trip and subsequently reconnect within a single 5-minute interval may still report non-zero energy over that period, particularly under AS/NZS 4777.2:2015 and AS/NZS 4777.2:2020 requirements, which allow reconnection within a few minutes. As a result, brief trip-and-reconnect events may not be detected using generation data alone, leading to potential undercounting of event-related tripping. This limitation reinforces the value of complementary error-log data where available and is a key motivation for the dual-method approach adopted in this study. Using both datasets together offers a cross-validated perspective on disturbance ride-through, supporting analysis of system size, geographic distance, DNSP, and manufacturer effects with greater confidence than either method alone.

Table 5. Monitoring coverage, trip counts, and error log availability for the six AEMO-reported grid events (as of 4 July 2025)

Event #	State	Type of event	Unique Sites	Sites with generation data	Inverters with generation data ²⁰	Sites with error code logs (Inverter Brand 5 only) ²¹	Inverters with error code logs (Inverter Brand 5 only) ^{21, 22}	Tripped Sites - Approach 1	Tripped Sites - Approach 2 (Inverter Brand 5 only) ²²
1	VIC	Voltage deviation	405	165	298	52	77	42	21
2	SA	Voltage deviation	89	53	143	14	24	3	0
3	SA	Voltage deviation	89	53	144	14	25	0	0
4	QLD	Voltage deviation	235	134	270	16	50	4	1
5	TAS	Voltage deviation	25	21	25	10	11	0	0
6	SA	Voltage deviation	89	66	182	22	52	4	0

Table 5 shows that although Diagno monitors hundreds of DPV systems in South Australia, Queensland, and Tasmania, most events in these states recorded only zero to four confirmed trips, too few for robust statistical analysis. In contrast, the Victorian event of February 2024 generated the only sizeable trip counts. Event #1 provided the largest sample of tripped sites and was therefore selected for detailed classification and fault-code analysis in the next section (Section 4). Fault-code statistics in the main text are limited to the sites that have *Inverter Brand 5* inverters only that returned complete, timestamped logs. Although API scripts were developed for all five inverter brands, *Inverter Brand 5* was the only manufacturer that consistently provided complete and timestamped logs during the study period. Other brands experienced one or more of the following issues:

- **Limited historical depth** - Several OEM services expose only live or recent alerts, making it impossible to reconstruct events after the fact. In practice, observed retention windows varied by manufacturer, ranging from approximately three months to six months, and in some cases up to one year, or more.
- **Access control or authentication failures** – Requirements such as paid licences, IP whitelisting²², or per-device tokens created bottlenecks when hundreds of API calls were needed within a short time frame. In practice, these barriers are primarily commercial. Some OEMs (e.g. *Inverter Brand 2* and *Inverter Brand 3*) operate paid API models, typically involving either a per-site monthly licence fee (often scaled by AC capacity) or negotiated, usage-based data packages, which might limit the feasibility of large-scale, retrospective event analysis.
- **Inconsistent time stamps** – Even when fault codes were retrieved, inverter clocks were often unsynchronised with a common time source, complicating alignment with market-time references.
- **Non-specific status flags** – Some devices returned only generic status indicators that could not be mapped to explicit fault codes.

²⁰ The inverter counts are higher than the site counts because some sites host multiple inverters.

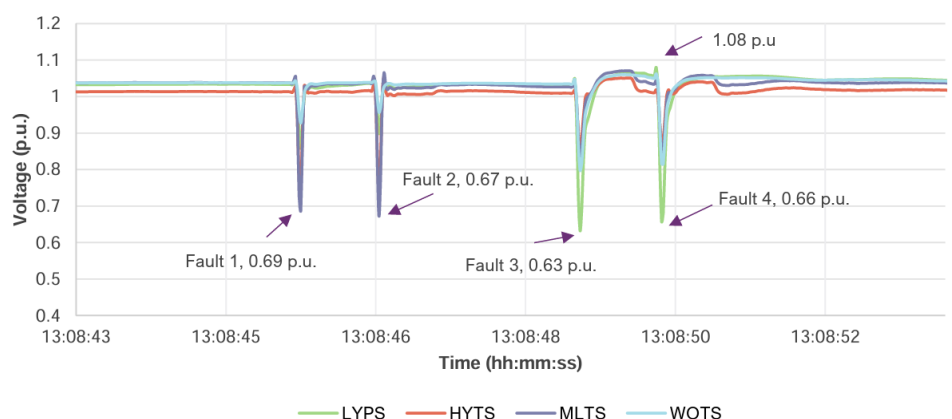
²¹ The tripped sites are not representative across the five inverter brands available in the Diagno API; however, they are listed here for reference to highlight the limitations of Approach 2, which arise from data-fetching issues in certain inverter APIs.

²² IP whitelisting refers to an access-control mechanism where API requests are only accepted from pre-approved network addresses. This requires advance coordination with the OEM to register specific IP addresses, enabling authorised large-scale or high-volume API queries.

4 Showcase event: Trip of Moorabool – Sydenham 500 kV lines

4.1 Description

On 13 February 2024 at 13:08 hrs in Victoria, the Moorabool (MLTS) – Sydenham (SYTS) No. 1 and No. 2 500 kV lines tripped after the collapse of six 500 kV towers. This caused the loss of all four Loy Yang A generating units, Dundonnell Wind Farm (tripped as designed under the Southwest 500 kV control scheme), and Yaloak South Wind Farm. In total, about 2,690 MW of generation and 1,000 MW of load were lost. Voltage depression during the incident reached as low as 0.63 p.u. across Victoria, with four faults identified in preliminary phasor measurement unit (PMU) data analysis (see Figure 5).



WOTS: Wodonga Terminal Station. LYPS: Loy Yang Power Station. LYPS is connected to Loy Yang A Power Station, Loy Yang B Power Station, Valley Power and the Basslink interconnector.

Figure 5. Positive sequence voltage throughout Victoria on 13 February 2024 (Source: AEMO).¹⁴

The MLTS – SYTS No. 1 and 2 500 kV lines grid event occurred at market time; however, inverters are storing the data the portal following the local time. Therefore, we converted the market time (13:08:48) to the local time (14:08:48) on the day of analysis to align the event time correctly with the inverter’s APIs.

For this event, we collected AC generation and tripping information for all monitored DPV sites located within Victoria, specifically identifying sites that tripped within the two consecutive 5-minute sampling intervals immediately following the event timestamp (14:08:48), corresponding to the 14:10 and 14:15 data points. In total, historical AC generation data was available for 165 sites, encompassing 298 inverters at the event window, which can be useful for approach 1 (power-signal analysis). However, for approach 2 analysis, one OEM (*Inverter Brand 5*) was able to be successfully accessed, *Inverter Brand 5* which only has 52 sites and 77 inverters available in VIC. This disparity highlights the need for more standardised, interoperable inverter logging protocols to support large-scale disturbance analysis. The breakdown of sites by inverter brand is shown in Table 6.

Table 6. Breakdown per inverter brand and number of sites.

Inverter Brand	Number of sites (AC generation data)	Number of sites (Error code logs)
Inverter Brand 1	1	N/A
Inverter Brand 2	66	N/A
Inverter Brand 3	24	N/A
Inverter Brand 4	22	N/A
Inverter Brand 5	52	52

Total	165	52
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As a result, fault-code statistics in the main text are limited to the 52 *Inverter Brand 5* sites, while the power-signal analysis covers the full 165-site sample. These 165 sites represent the subset of the 405 onboarded Diagno sites that returned AC generation data on the event day and therefore formed the input population for both the power-signal analysis and subsequent fault-code queries. Of these 165 sites, 42 exhibited tripping behaviour in at least one post-event timestamp. Within the *Inverter Brand 5* subset, 21 sites recorded a tripping code in at least one post-event timestamp (as mentioned in Table 5).

A spatial heatmap of DPV systems experiencing tripping across Victoria during the time of the event is presented in Figure 6. The map shows the kernel density estimate (KDE) of sites that tripped within two timestamps after the grid-side event, focusing on systems with AC capacity >30 kVA. In Victoria, of the 165 sites with generation data on the event day, 105 systems were larger than 30 kVA. Of these, 41 systems exhibited tripping behaviour during the event window.

This size-dependence is consistent with AEMO’s event analysis²³, which reported substantially higher disconnection (“shake-off”) rates for larger 30-100 kW systems than for <30 kW systems in Victoria during the incident. The KDE heatmap highlights a broad geographic spread of near-simultaneous tripping among larger systems, with a higher density of affected sites around the Sydenham region. Colour intensity represents the relative density of tripped sites in each group, with higher values indicating greater concentrations of affected sites.

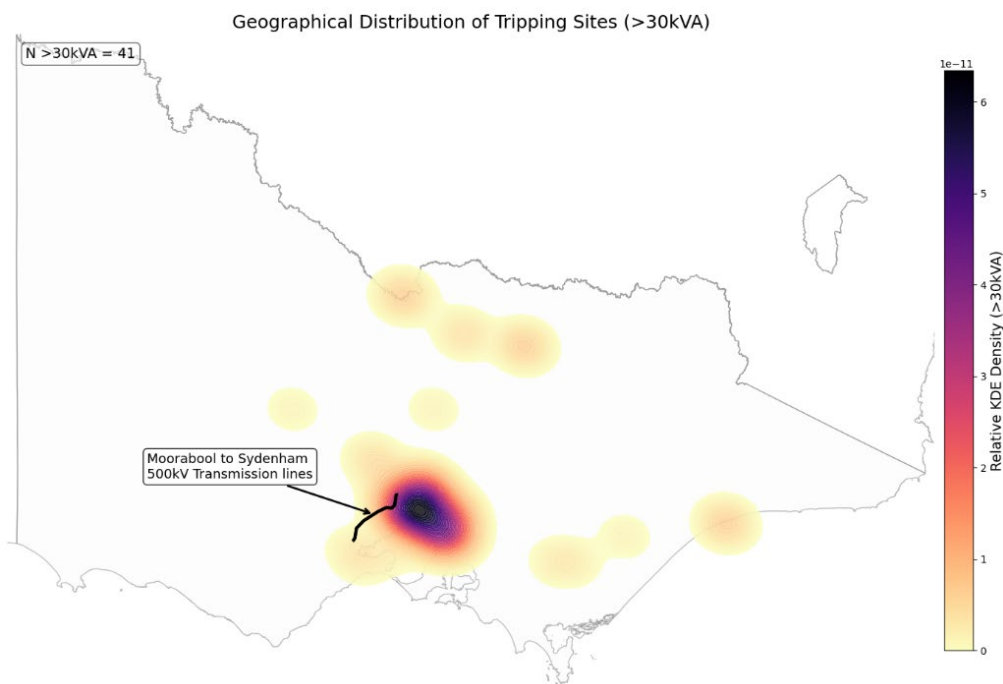


Figure 6. Spatial distribution of tripped DPV sites across Victoria following the grid-side event (Market time: 13 February 2024 [13:08:48 - 13:15:00]).

4.2 Classification

This section classifies tripped sites against a set of targeted research questions; each aimed at testing a plausible driver of inverter tripping susceptibility. The two complementary detection approaches – (i) inverter

²³ AEMO, *Final Report – Trip of Moorabool – Sydenham 500 kV No. 1 and No. 2 lines on 13 February 2024*, July 2025.

power-signal analysis (approach 1) and (ii) inverter error-code interrogation (approach 2) – provide a broadly consistent view of site-level responses to Event #1 (trip of Moorabool–Sydenham 500 kV lines).

To compare the effectiveness of both approaches, we have compared the results obtained from approach 1 (inverter power-signal analysis) and approach 2 (inverter error-code interrogation) for the *Inverter Brand 5* subset (n = 52 sites). Of these, 29 sites were flagged by approach 1 and 21 sites by approach 2, with 18 sites identified by both. This means 11 sites were detected only by approach 1 and three only by approach 2. Consequently, Figure 7 (left panel) shows that most sites flagged by the algorithm (approach 1) also recorded at least one fault code within two timestamps of the event (approach 2). Few sites reported a fault log without a matching power-to-zero signature. These cases likely reflect rapid curtailment that the 5-minute sampling interval could not fully capture (see Appendix 8.1). The right panel illustrates the distribution of fault categories, with Grid transient over-voltage and Grid power outage being the most common.

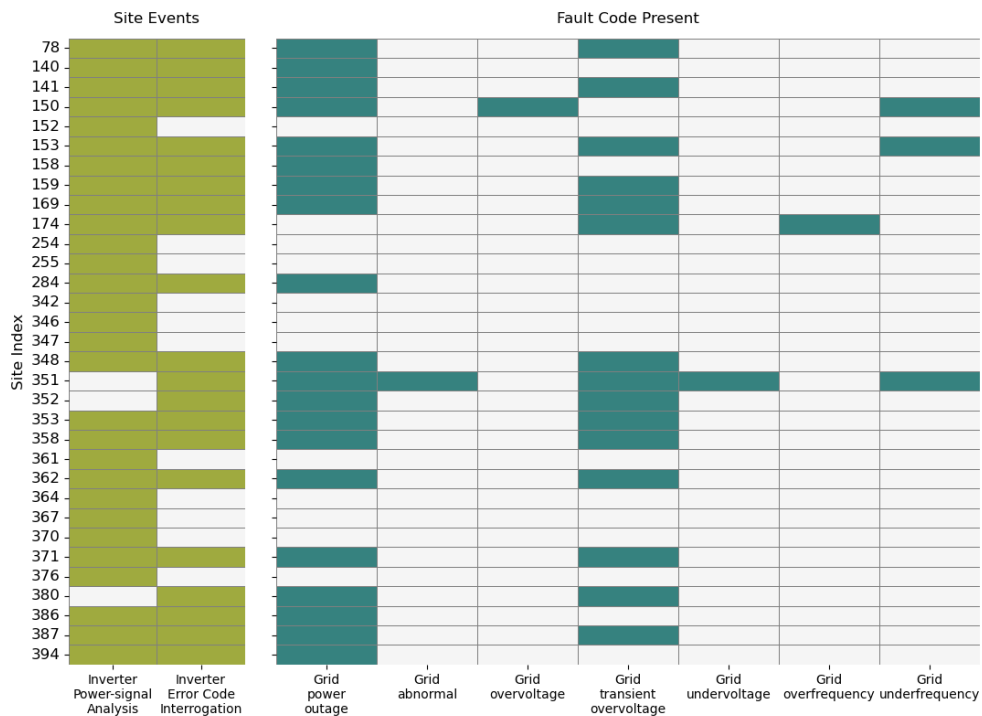


Figure 7. Combined event matrix for 32 *Inverter Brand 5*-monitored sites. (Left: binary presence of inverter power-signal analysis (approach 1) and of any *Inverter Brand 5* error code interrogation (approach 2); and Right: fault-category heatmap showing which sites recorded error logs in the 2 timestamps window following the event time). Of the 52 *Inverter Brand 5* sites with available data, 20 did not exhibit either a generation drop to zero or a relevant fault log during the event window and are therefore not shown.

4.2.1 Classifications based on inverter power-signal analysis (approach 1)

Once the trip flags are validated, subsequent analyses rely exclusively on the algorithm’s results to examine how tripping propensity varies across the following factors:

- **DNBP analysis:** Do sites in different DNBP service areas exhibit significantly different trip rates? (see Section 4.2.1.1)
- **Inverter settings:** Does installation date – used as a proxy for compliance with more recent AS/NZS 4777 standards – reduce tripping significantly? (see Section 4.2.1.2)
- **System size:** Are larger systems (>30 kVA) more likely to trip than smaller installations? (see Section 4.2.1.3)
- **Inverter brand:** Are there manufacturer-specific patterns indicating hardware sensitivities? (see Section 4.2.1.4)
- **Distance correlation:** How does trip probability change with increasing distance from the faulted transmission line? (see Section 4.2.1.5)

4.2.1.1 DNSP analysis

Tripping probability did not differ significantly across Victoria’s three DNSPs. While raw counts suggested slight variation between DNSPs, even after stratifying by inverter size (see Figure 8), the differences were minimal. No sub-30 kVA systems on the *DNSP 1* or *DNSP 3* networks, and only one of forty-two such systems on the *DNSP 2*, experienced a trip—reinforcing the earlier finding of strong resilience among smaller installations. In contrast, DPV systems >30 kVA exhibited consistently higher vulnerability across all DNSPs. To formally test the effect, a logistic-regression model with DNSP as a categorical predictor was fitted; the likelihood-ratio test returned no statistical significance (p-value = 0.70), indicating that DNSP membership accounts for virtually none of the observed variation. While the raw data hint at a possible gradient, a denser dataset would be required to confirm any DNSP-specific influence on tripping susceptibility.

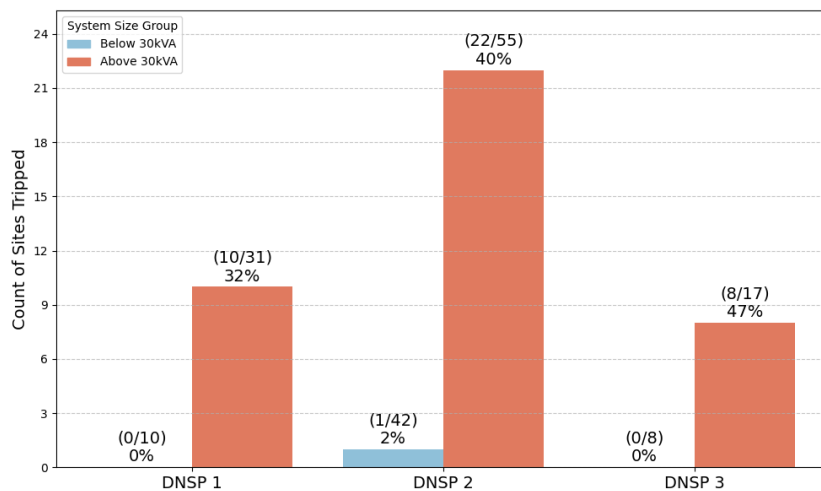


Figure 8. Tripping counts and rates by DNSP and system size group (Orange bars represent sites >30 kVA. Blue bars represent sites ≤30 kVA; and Values above each bar show “(tripped / total)” and the corresponding percentage).

4.2.1.2 Inverter settings

The analysis found no statistically significant relationship between the AS/NZS 4777 standard in force at installation and the likelihood of a tripping event. Using each site’s installation date, and the enforcement timeline in Appendix 8.2 (See Table 10), we assigned the applicable AS/NZS 4777 version at the time of commissioning. AEMO similarly stratified observed shake-off by standard proxy / installation cohort and system size for this incident²⁴.

Figure 9 presents the raw tripping proportions by standard and system-size category. While point estimates range from 24 % for large systems subject to AS/NZS 4777.2:2015 to 54 % for the large AS/NZS 4777.2:2020 cohort, statistical testing does not support a consistent pattern. A logistic-regression model, with one-hot-encoded standards as predictors for the binary trip outcome, returned no significant coefficients, where the likelihood-Ratio test p-value (LR p-value)²⁵ equals to 0.01566, and a negligible pseudo-R-squared (pseudo-R²)²⁶ equals to 0.05540. Even though the visual representation might indicate that the standard might play a role, the statistical analysis does not support a standalone effect of the applicable standard once sample size limitations, manufacturer-specific confounding, and uncertainty in inferred compliance are considered. In this

²⁴ AEMO, *Final Report – Trip of Moorabool – Sydenham 500 kV No. 1 and No. 2 lines on 13 February 2024*, July 2025.

²⁵ Likelihood-Ratio test p-value.

²⁶ McFadden R-squared, that used the previously mentioned likelihood ratio values.

study, standards were inferred from installation dates rather than confirmed inverter settings and therefore act as proxies rather than definitive indicators of configured behaviour.

In principle, systems installed after the 2020 amendment should ride through disturbances more reliably. However, the limited sample size, mixed directional trends, and incomplete metadata prevent firm conclusions. Metadata gaps are notable, 26 of the 165 sites (15 %) lacked a reliable installation date and were grouped as “Unknown or flagged date,” showing an intermediate trip rate (25 % for >30 kVA systems). Notably, AEMO reported evidence of improved ride-through for <30 kW systems installed from April 2023 (lower shake-off than earlier cohorts) but also found no reduction in shake-off for the 30-100 kW size category²⁷.

Consistent with earlier findings, ≤30 kVA installations rarely tripped regardless of the standard in force. A more definitive assessment would require a larger dataset with verified protection-setting records to evaluate the real-world impact of AS/NZS 4777 updates on disturbance ride-through performance.

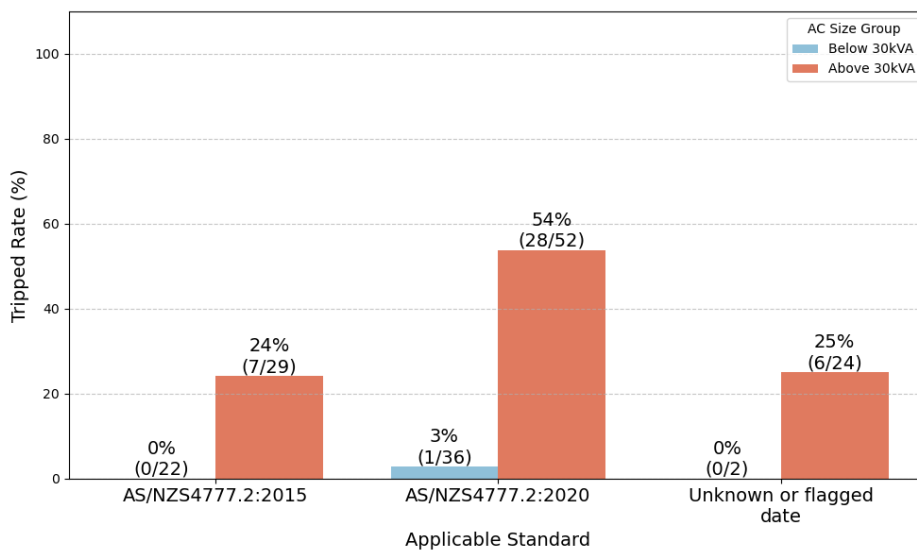


Figure 9. Tripping rate by expected applicable standard and system-size group (Blue bars show ≤30 kVA systems and orange bars show >30 kVA systems; and Labels give tripped/total counts and percentages for each category).

4.2.1.3 System size

System size emerges as a strong predictor of tripping behaviour during the event. Figure 10 compares outcomes for installations rated at ≤30 kVA against those above this threshold, with the larger group further broken down into individual capacity bands.

The contrast is stark: only 1 of 60 small systems (2 %) tripped, compared with 41 of 105 larger systems (39 %). A chi-squared contingency test confirms this difference is highly significant (chi-squared statistic (χ^2)²⁸ = 26.2, and p-value²⁹ = 3.1×10^{-7}). This direction and magnitude are broadly consistent with AEMO’s incident analysis, which observed very low shake-off rates for <30 kW systems compared with much higher disconnection rates for 30-100 kW systems during the same event.

²⁷ AEMO, *Final Report – Trip of Moorabool – Sydenham 500 kV No. 1 and No. 2 lines on 13 February 2024*, July 2025.

²⁸ It is the test statistic for a chi-squared contingency test on a 2x2 matrix. This matrix is built with below or above 30kVA and tripped versus not tripped.

²⁹ It is the probability of obtaining a test statistic at least as extreme as the one observed. p-value defined as 0.05 previously, anything below that considered to be significant.

To quantify the effect, a binary logistic regression was run with a single predictor—capacity >30 kVA. The resulting coefficient of 3.63 ± 1.03 (logistic regression coefficient \pm standard error)³⁰ corresponds to an odds ratio of 38, indicating that, all else equal, a system >30 kVA is nearly forty times more likely to trip than a smaller one. The model explains about 20 % of the deviance (pseudo-R² = 0.20) and passes the likelihood-ratio test (p-value = 1.5×10^{-9}).

These results reinforce the size dependency first suggested by the spatial analysis: as inverter capacity increases, ride-through capability under this disturbance declines sharply.

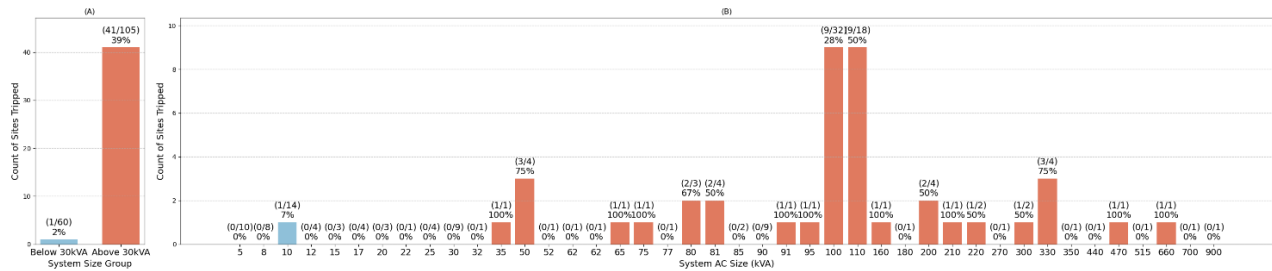


Figure 10. Tripping incidence by system size (Panel (A) compares sites ≤30 kVA with those >30 kVA; Panel B shows counts and trip fractions for individual AC system sizes (kVA); and Labels give tripped/total counts and corresponding percentages for each bar).

4.2.1.4 Inverter brands

Raw counts hint at brand-specific differences, but formal modelling yields inconclusive results. Figure 11 groups trip outcomes by inverter brand and size class. Out of the 52 *Inverter Brand 5* systems, 45 were large systems (>30 kVA), and 29 out of these tripped (at a rate of 64%). Large *Inverter Brand 2* and *Inverter Brand 4* systems followed, while, in contrast, all large *Inverter Brand 3* and *Inverter Brand 1* sites rode through the disturbance, although their sample sizes are small (23 and 1 units, respectively). Small systems (≤30 kVA) rarely tripped regardless of brand.

To adjust for size effects, a logistic regression was fitted with brand as a categorical predictor. While the likelihood-ratio test was significant (likelihood-ratio chi-squared statistic, $LR \chi^2 = 23.1$, and p-value < 0.001), the model failed to converge cleanly, returning extreme coefficients and standard errors due to quasi-separation—cases where certain brands perfectly predict non-tripping (e.g., all *Inverter Brand 3* sites). This makes maximum-likelihood estimates unstable or unidentifiable.

The key takeaway is therefore qualitative: the high trip rate in *Inverter Brand 5* units may reflect brand-specific protection settings, or simply their predominance in the large-capacity segment most prone to tripping. A further contributing factor may relate to measurement resolution: if certain inverter models take longer to reconnect following a disturbance, trips to zero are more likely to be captured within a 5-minute sampling interval, whereas shorter-duration trips on other models may go undetected. With the current dataset, these effects cannot be disentangled. A more balanced cross-manufacturer sample, higher-resolution telemetry, or a mixed-effects modelling approach would be required to draw firm conclusions regarding manufacturer-specific versus size-driven susceptibility.

³⁰ It is calculated in relation to the predictor (capacity >30 kVA).

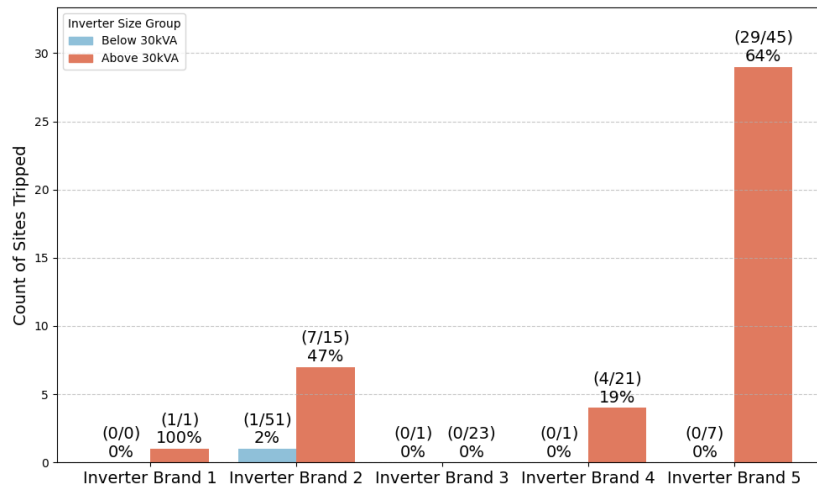


Figure 11. Tripping counts and rates by inverter brand and system-size group.

4.2.1.5 Distance correlation

Distance from the fault location was not a strong or consistent predictor of tripping behaviour, even when systems were grouped by size.

To test whether proximity to the grid event influenced ride-through, we calculated the straight-line distance from each DPV site to the Moorabool–Sydenham 500 kV transmission lines No. 1 and 2 corridors:

- Site coordinates were taken from Diagno metadata.
- Transmission line geometry was extracted from the Electricity Transmission Lines layer of the Australian Digital Atlas.¹³
- For each site, we computed the shortest geodesic distance to the nearest point on the transmission-line polyline.
- This distance (km) was appended to the master dataset for statistical analysis and visualisation.

Overall, Figure 12 plots distance (x-axis) against DPV system size (y-axis), with tripped sites marked by orange “X” symbols and non-tripped sites by light-blue circles.

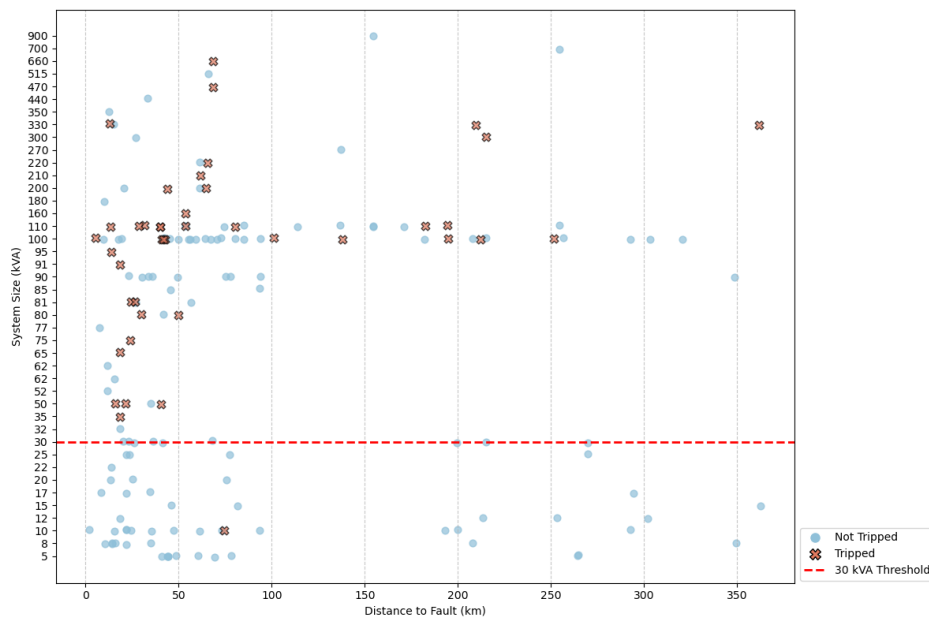


Figure 12. Scatterplot of tripping outcome by distance and system size (Light-blue circles represent sites that did not trip; Orange X-markers represent sites that did trip; and the x-axis gives the straight-line distance (km) from each site to the nearest point on the Moorabool–Sydenham 500 kV corridor).

A logistic regression was used to assess whether distance to the fault influenced the likelihood of tripping. The model found no statistically significant relationship (p -value = 0.332), with a negligible effect size and minimal explanatory power (pseudo- R^2 = 0.005). This indicates that distance was not a meaningful predictor of tripping for this event. To explore potential DPV system size effects, systems were stratified into ≤ 30 kVA (blue) and > 30 kVA (red) groups (see Figure 13). Small systems showed uniformly low trip probabilities across the 0–350 km range, with only one tripped site observed (p -value = 0.825), resulting in a flat logistic fit. Large systems exhibited a slight negative trend—trip probability decreasing with distance—but the effect was not statistically significant (p -value = 0.447). These results suggest that system size, rather than proximity to the fault, is the primary driver of tripping differences observed here.

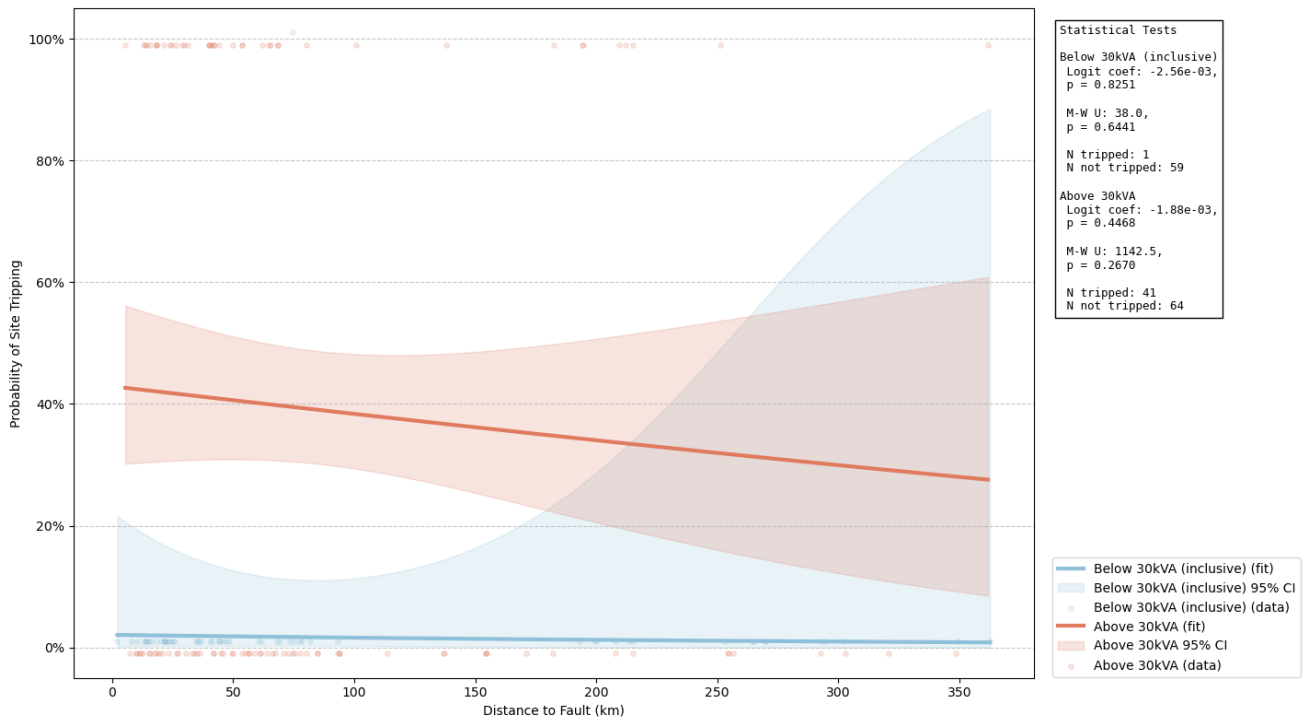


Figure 13. Probability of tripping versus distance to fault, stratified by system size. Points denote individual sites. Solid lines are logistic fits. Shaded bands are 95 % confidence intervals, reflecting uncertainty structure and data density, with tighter bands representing less uncertainty.

4.2.2 Classifications based on inverter error code interrogation (approach 2) - *Inverter Brand 5* Fleet only

Fault-code API queries were attempted for all five inverter brands listed in Table 6, but only *Inverter Brand 5* consistently returned complete, timestamped error logs. As a result, tripping behaviour for the *Inverter Brand 5* subset ($n = 52$ sites) was analysed to examine how tripping propensity varied with the following factors:

- **Inverter settings** based on fault-code-detected sites (see Section 4.2.2.1)
- **System size** based on fault-code-detected sites (see Section 4.2.2.3)
- **Inverter settings and distance correlation** based on fault-code-detected sites (see Section 4.2.2.2)

On the event date, a full day of *Inverter Brand 5* inverter error codes was captured to demonstrate the value of this approach in detecting underlying faults at the distribution network level. Figure 14 plots every fault code returned by the *Inverter Brand 5* API on the day of the Moorabool–Sydenham disturbance, colour-coded by harmonised keywords derived from the vendor’s model-specific manuals. The workflow involved querying each *Inverter Brand 5* inverter once via the proprietary API endpoint, mapping raw numerical codes to plain-language categories (e.g., Grid transient overvoltage, Grid power outage, Grid undervoltage), and aligning results to local time for comparison with power-signal trip flags.

The timeline shows three distinct clusters of activity:

- **Early isolated faults (09:30–11:30)** – Four sites recorded isolated grid power outage messages several hours before the network event.
- **One-hour-offset cluster (13:08 plot time)** – Thirteen sites reported a single grid power outage at what appears to be exactly one hour earlier than the actual 14:08 event. This offset is likely a timestamp/time-zone artefact, happening almost exactly one hour before the event. The Inverter Brand 5 logs carry no time-zone metadata, consistent with a daylight-saving misconfiguration on these devices.
- **Main event cluster (14:08 onwards)** – Within seconds of the 14:08:48 disturbance (red dashed line), 21 of the 52 *Inverter Brand 5* inverters logged grid power outage errors almost simultaneously. Many remained latched in this state, producing repeated restart attempts and multiple post-event fault entries throughout the afternoon.

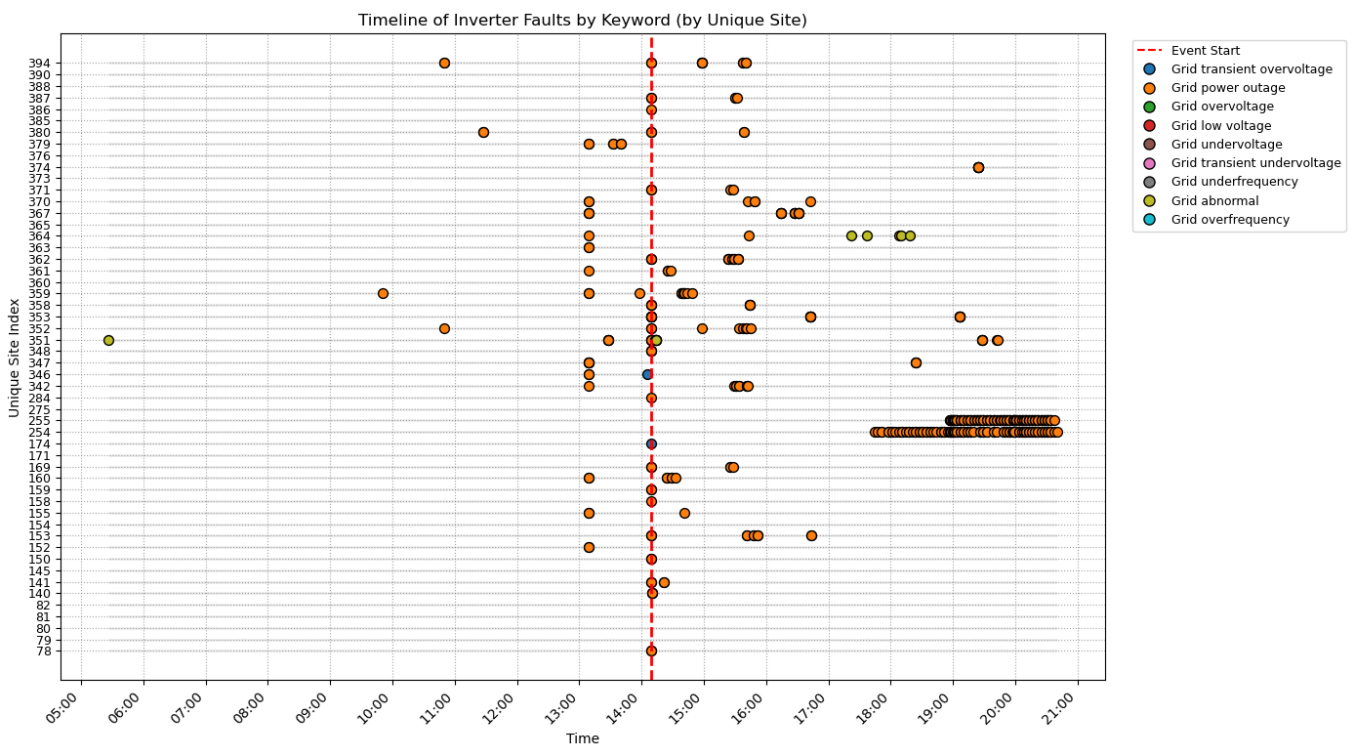


Figure 14. Twenty-four-hour timeline of *Inverter Brand 5* inverter fault messages on 13 February 2024 (Each dot represents a fault code reported by one *Inverter Brand 5* site; colours correspond to the harmonised keyword shown in the legend; and the vertical red dashed line marks the transmission-level grid event at 14:08 local time).

Overall, the 24-hour view shows that *Inverter Brand 5* fault codes generally align with the timing of the transmission-level event, but a subset appears clock-shifted (most likely a daylight-saving/timestamp offset), highlighting the importance of validating device-level timestamps when integrating fault logs with power-signal analyses.

Building on the full-day timeline, Figure 15 zooms into the critical 15-second interval immediately following the 14:08:48 disturbance to highlight the near-instantaneous inverter responses. The red dashed line again marks the official transmission-level event timestamp. Within one second of the trip, a wave of Grid transient overvoltage messages (blue dots) appears almost simultaneously across many sites, suggesting that *Inverter Brand 5* inverters detected the sudden voltage spike as the primary trigger. This is quickly followed by a slightly delayed band of Grid power outage codes (orange dots) between $t + 1$ s and $t + 3$ s, indicating a sequential protective response.

Beyond this initial burst, only one isolated log appears outside the first three seconds, underscoring that almost all *Inverter Brand 5* units reacted and recorded their status change within the brand’s one-second logging resolution. When viewed alongside the full-day fault log (see Figure 14), this zoomed-in view reinforces the value of API-sourced error codes for pinpointing the exact nature and timing of inverter behaviour during distribution-level disturbances.

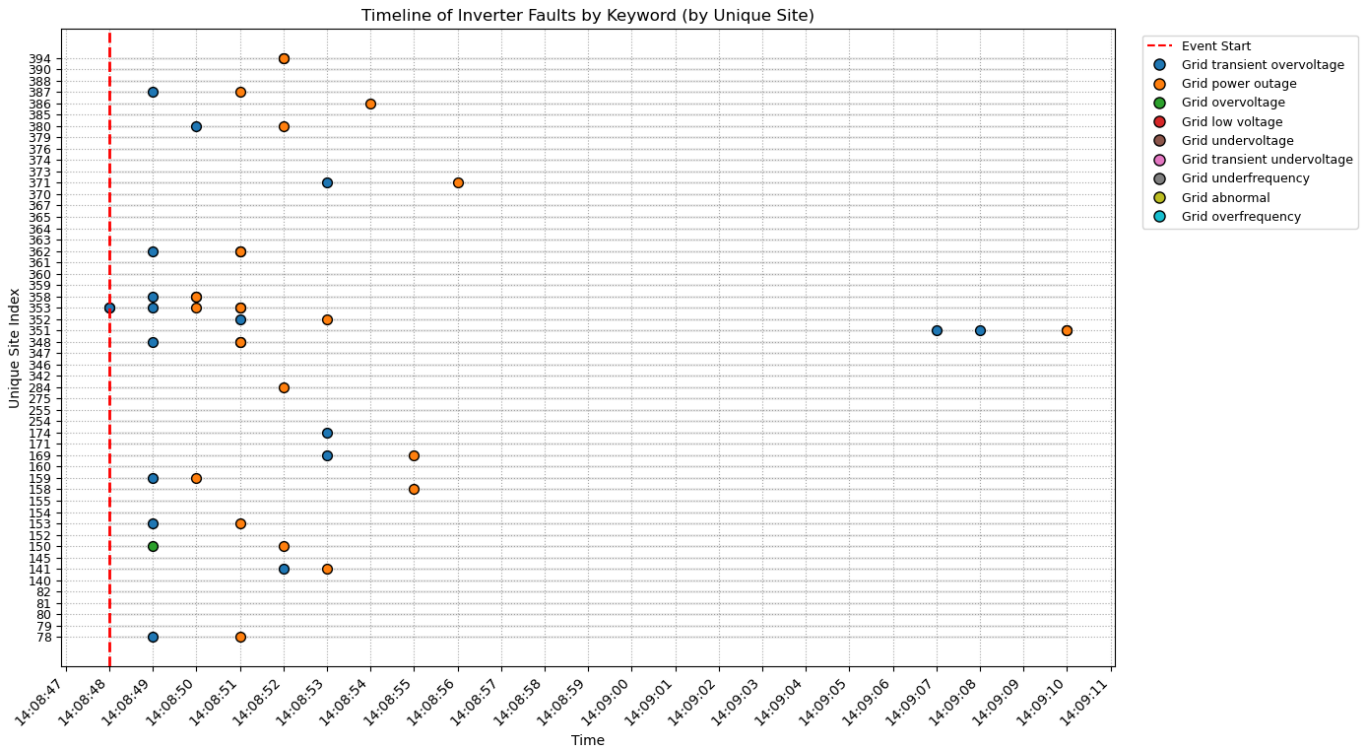


Figure 15. Fifteen-second timeline of *Inverter Brand 5* fault messages following the 14:08:48 transmission-line trip (Each dot represents a fault log from an *Inverter Brand 5* site; and colours correspond to the harmonised keywords in the legend).

4.2.2.1 Inverter settings based on fault code detected sites

To examine whether inverter settings influenced tripping behaviour, *Inverter Brand 5* sites with available fault-code logs were grouped by their declared compliance standard. Figure 16 presents a 15-second window after the 14:08:48 disturbance, with each dot representing a fault event colour-coded by harmonised keyword and positioned according to the site’s registered standard.

Two main patterns emerge. First, across both AS/NZS 4777.2:2015 and AS/NZS 4777.2:2020 installations, the earliest responses occur within one second of the transmission-level event (red dashed line), dominated by Grid transient over-voltage entries (blue dots). This suggests that regardless of the version, *Inverter Brand 5* inverters tended to detect and report the initial voltage excursion in the same way.

Second, the majority of Grid power outage codes (orange dots) appear 1–3 seconds later, consistent with a protective sequence in which an over-voltage trigger is followed by disconnection or loss-of-supply detection. Sites commissioned under AS/NZS 4777.2:2020 after AEMO’s ‘compliance improvement’ activities do not exhibit a materially different timing profile from earlier 2020-era sites. In this event, the data do not show a measurable effect attributable to the compliance-improvement period; a reasonable interpretation is that many systems were already being configured correctly from 2020.

One isolated Grid overvoltage entry (green) appears in the AS/NZS 4777.2:2020 cohort, but the scarcity of such code’s limits interpretation.

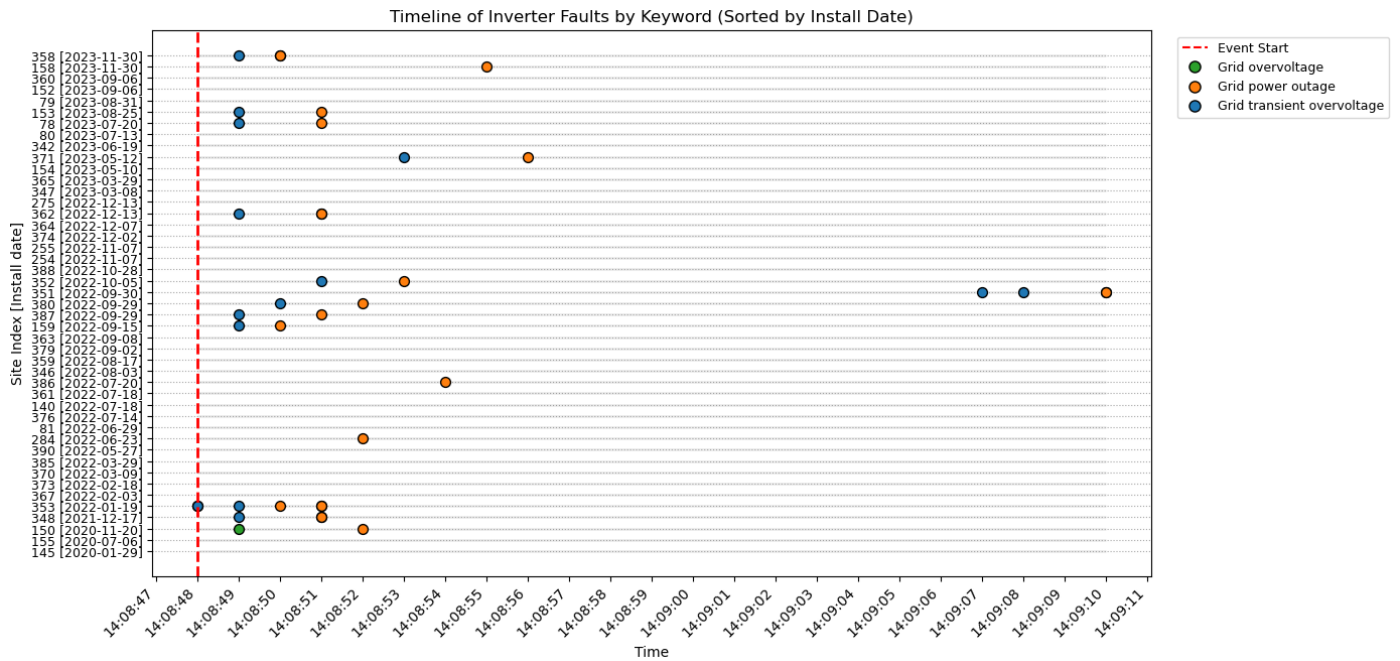


Figure 16. Fifteen-second timeline of *Inverter Brand 5* inverter fault logs (Each dot represents a single fault message, colour-coded by harmonised keyword; the vertical red dashed line marks the 14:08:48 transmission-level event; and earlier dots indicate pre-event codes, while subsequent clusters reflect near-simultaneous responses across both standard versions).

4.2.2.2 Inverter settings and distance correlation based on fault code detected sites

To explore whether proximity to the disturbance source influenced fault detection patterns under different inverter compliance settings, *Inverter Brand 5* sites with available fault-code logs were plotted by both their AS/NZS 4777.2 standard version and their distance to the Moorabool–Sydenham transmission line (see Figure 17).

Across the 15-second window following the 14:08:48 disturbance, the majority of sites—irrespective of compliance standard—recorded Grid transient over-voltage (blue) messages within one second of the event, followed closely by Grid power outage (orange) entries within 1–3 seconds. This consistent timing suggests that the physical characteristics of the disturbance dominated the detection response, with little evidence that compliance setting or site distance materially altered the sequence.

While some variation in reporting order is visible, there is no clear trend where sites further from the MS line exhibited delayed fault logging or a different error-type distribution. For example, near and far sites alike reported both over-voltage and outage codes within the same sub-second bands. The only Grid overvoltage (green) entry occurred at an intermediate distance, further indicating no simple spatial correlation.

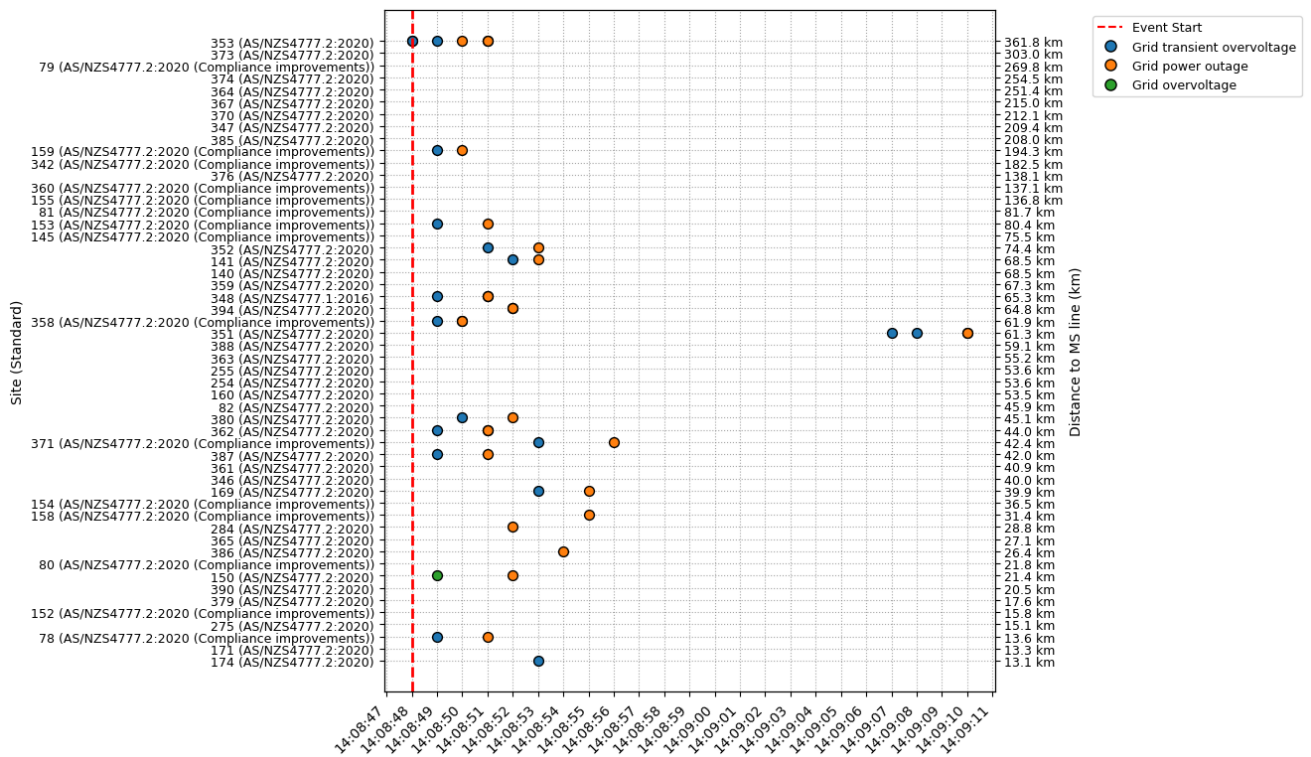


Figure 17. Fifteen-second timeline of *Inverter Brand 5* inverter fault logs following the 14:08:48 grid disturbance, grouped by AS/NZS 4777.2 compliance standard and annotated with each site’s distance to the Moorabool–Sydenham transmission lines No. 1 and 2. (Colours correspond to harmonised fault-code categories; the red dashed line marks the official event timestamp).

Overall, this combined compliance-and-distance view reinforces findings from Sections 4.2.2.1 and 4.2.2.2: for this event, *Inverter Brand 5* inverter fault responses were largely synchronous and homogenous across the geographic spread, implying that the magnitude and characteristics of the voltage excursion together with local protection settings were the dominant triggers, rather than distance from the event or the nominal compliance standard.

4.2.2.3 System size based on fault code detected sites

Building on the *Inverter Brand 5*-specific API analysis, where complete and timestamped fault logs were retrieved for all detected events, we now examine whether the likelihood of capturing both a power-to-zero trip signature, and a corresponding inverter fault code varies with system size. This step is important because the earlier fault-timeline plots revealed clear patterns in the timing and type of *Inverter Brand 5* error messages but did not distinguish whether such responses were consistent across different capacity classes, in which, Figure 18 summarises this concordance.

Accordingly, smaller *Inverter Brand 5* systems (≤ 30 kVA) showed no evidence of tripping or fault logging, reinforcing their apparent immunity to the over-voltage disturbance. In contrast, larger systems (> 30 kVA) exhibited significantly higher trip and fault-code incidence – 64% registered a clear trip in the power-signal data, and 47% recorded an inverter error message. Within this dataset, this pattern indicates that system size, in combination with manufacturer-specific protection behaviour and inverter production date, is an important predictor of tripping response for *Inverter Brand 5* systems during this period. This suggests that system size is an important factor in both the physical and logged response to grid disturbances for this brand in this era and confirms the value of using the power-signal algorithm as a robust primary classifier while retaining fault-log analysis for deeper diagnostic insight.

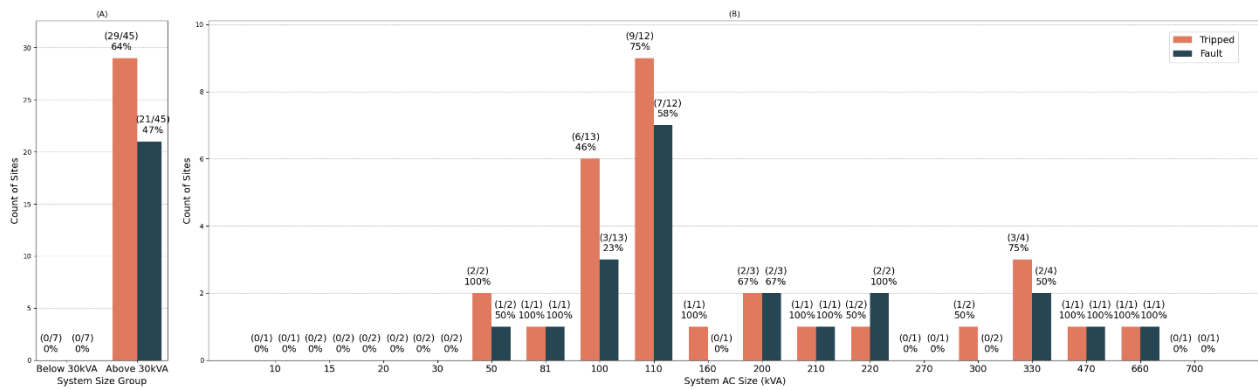


Figure 18. Influence of system size on detection concordance [(A) Aggregated counts for two capacity bands (≤ 30 kVA, > 30 kVA); (B) Breakdown by nominal AC rating (kVA). Orange bars = algorithm-detected trips; Blue bars = Inverter Brand 5 fault logs; and Numbers above each bar indicate (tripped / total) and percentage].

4.3 Impact of Interface protection device (IPD) settings on inverters tripping

IPD devices are designed to disconnect DPV from the grid under abnormal voltage or frequency conditions to protect both network assets and customer equipment. While essential for safety, IPD setpoints and configurations can significantly influence whether inverters ride through or disconnect during grid disturbances. This section examines the relationship between IPD settings and inverter tripping behaviour using data from a subset of 13 sites where IPD configuration information is available. The analysis integrates two detection methods – Approach 1 (power-signal analysis) and Approach 2 (inverter fault log interrogation). Accordingly, Table 7 shows each site’s DNSP, system size, inverter standard, and distance from the event, while Table 8 details the IPD brand, model, and setpoints for over-voltage, under-voltage, frequency, vector shift, ROCOF, and reconnection delay.

Table 7. Sites Included in Secondary Protection Settings Analysis and Detection Outcomes for Approaches 1 and 2. Site IDs are consistent with those used in the fault-code analysis to allow direct cross-referencing.

Site ID	Inverter brand	System size (kVA)	DNSP	# of inverters	Distance to event (km)	Expected inverter standard	Tripped Sites – Approach 1	Tripped Sites – Approach 2 (Inverter Brand 5 only) ²²
140	Inverter Brand 5	470	DNSP 2	5	68.5	AS/NZS4777.2:2020	TRUE	TRUE (Grid power outage)
141	Inverter Brand 5	660	DNSP 2	5	68.5	AS/NZS4777.2:2020	TRUE	TRUE (Grid power outage / Grid transient overvoltage)
174	Inverter Brand 5	330	DNSP 2	1	13.1	AS/NZS4777.2:2020	TRUE	TRUE (Grid overfrequency / Grid transient overvoltage)
329	Inverter Brand 2	65	DNSP 3	3	18.3	Unknown ³¹	TRUE	N/A

³¹ Unknown due to inconclusive installation date (e.g. 1st of January 2000).

Site ID	Inverter brand	System size (kVA)	DNSP	# of inverters	Distance to event (km)	Expected inverter standard	Tripped Sites – Approach 1	Tripped Sites – Approach 2 (Inverter Brand 5 only) ²²
275	Inverter Brand 5	330	DNSP 2	3	15.1	AS/NZS4777.2:2020	FALSE	FALSE
349	Inverter Brand 3	180	DNSP 2	3	10.0	AS/NZS4777.2:2015	FALSE	N/A
32	Inverter Brand 2	81	DNSP 3	3	24.6	AS/NZS4777.2:2015	TRUE	N/A
34	Inverter Brand 2	81	DNSP 2	3	56.6	AS/NZS4777.2:2015	FALSE	N/A
263	Inverter Brand 3	440	DNSP 3	4	33.1	AS/NZS4777.2:2020	FALSE	N/A
264	Inverter Brand 2	350	DNSP 3	4	12.7	AS/NZS4777.2:2020	FALSE	N/A
267	Inverter Brand 2	85	DNSP 2	4	45.5	Unknown ³²	FALSE	N/A
285	Inverter Brand 2	95	DNSP 2	4	14.0	AS/NZS4777.2:2015	TRUE	N/A
306	Inverter Brand 2	52	DNSP 2	2	11.5	AS/NZS4777.2:2015	FALSE	N/A

Table 8. Secondary Protection Settings for Analysed Sites. N/A denotes a blank or missing value in the source data.

Site #	IPD Brand	IPD Model	Protection Function	Over Voltage 1 (V)	Over Voltage 2 (V)	Under Voltage (V)	Sustained Over Voltage (V)	Over Frequency (Hz)	Under Frequency (Hz)	Vector Shift (DEG)	ROCO F (Hz/s)	Reconnect on Delay (s)
140	IPD BRAND 1	MODEL 1-A	Set point	260	N/A	180	255	52	47	20	4	
			Time delay (s)	2	N/A	2	15	2	2	0	0.25	60
141	IPD BRAND 1	MODEL 1-A	Set point	260	N/A	180	255	52	47	20	4	
			Time delay (s)	2	N/A	2	15	2	2	0	0.25	60
174	IPD Brand 2	Model 2-A	Set point	260	265	180	258	52	47	8	1	
			Time delay (s)	2	0.2	2	15	0.2	2	2	2	60
329	IPD BRAND 1	MODEL 1-A	Set point	260	N/A	180	255	52	47	8	1	
			Time delay (s)	1.8	N/A	1.8	0	1.8	1.8	0.045	0.5	60
275	IPD Brand 2	Model 2-A	Set point	260	N/A	180	255	52	47	8	1	
			Time delay (s)	2	N/A	2	15	2	2	2	2	60
349	IPD Brand 2	Model 2-A	Set point	260	265	200	N/A	52	48	8	1	
			Time delay (s)	1	N/A	1	N/A	N/A	1	N/A	1	60
32	IPD Brand 2	Model 2-A	Set point	260	N/A	180	255	52	47	8	1	
			Time delay (s)	2	N/A	2	15	2	2	2	2	60
34	Unknown	Unknown	Set point	260	N/A	180	255	52	47	8	3	
			Time delay (s)	2	N/A	2	15	2	2	2	1	60
263	IPD Brand 2	Model 2-A	Set point	260	N/A	180	255	52	47	8	1	
			Time delay (s)	2	N/A	2	15	2	2	0	2	60
264	IPD BRAND 1	MODEL 1-A	Set point	265	275	180	258	52	47	20	4	
			Time delay (s)	2	0.2	11	3	2	2	2	0.25	60
267	Unknown	Unknown	Set point	260	N/A	216	255	52	48	8	1	
			Time delay (s)	1.8	N/A	1.8	N/A	1.8	1.8	0.045	N/A	60
285	Unknown	Unknown	Set point	260	N/A	180	255	52	47	8	1	
			Time delay (s)	1.8	N/A	1.8	0	1.8	1.8	0.045	0.5	60
306	Unknown	Unknown	Set point	260	N/A	180	255	52	47	8	3	
			Time delay (s)	2	N/A	2	0	2	2	0	1	60

4.3.1 Comparative patterns between tripped and non-tripped sites (Approach 1)

This section compares IPD settings, DNSP distribution, and specific voltage/frequency protection settings between sites that experienced tripping events and those that did not, as identified through inverter power-signal analysis (Approach 1). Given the limited sample (≈ 13 sites with known IPD settings) and multiple exceptions for each rule-of-thumb, the analysis is inconclusive. We do not identify a single factor (standard, DNSP, or specific IPD threshold) that reliably separates tripped from non-tripped sites in this event. While some tripped sites have settings such as $OV_2 \approx 265$ V or sustained $OV \approx 258$ V, there are counter examples where similar settings did not result in tripping. Accordingly, any apparent patterns should be treated as indicative only and not causal. In addition, this disturbance was voltage driven. There is no evidence in our dataset of frequency or ROCOF excursions breaching many devices' protection ranges; therefore, ROCOF and some frequency settings are likely not explanatory for this event.

4.3.2 Comparative patterns between faulted and non-faulted sites (Approach 2)

This subsection examines IPD configuration differences between *Inverter Brand 5* sites that recorded inverter fault events and those that did not, based on inverter fault log interrogation (Approach 2). Results are again inconclusive. Although several faulted sites show higher sustained-OV or include OV_2 thresholds, we also observe non-faulted sites with similar configurations. Given the small Brand 5 cohort with complete, timestamped logs and the absence of clear frequency/ROCOF stress in this event, we cannot attribute fault logging to those settings.

With the current dataset, we cannot assert that any specific IPD or compliance setting caused tripping/faults. A larger, more balanced sample plus verified per-site commissioning records and high-rate voltage traces would be required to test these relationships robustly.

5 Key insights and data-specific challenges

5.1 Key insights

The detailed analysis of the showcase event (Event #1: Sydenham-Moorabool transmission line disturbance) reveals a clear set of technical and operational patterns that underpin tripping behaviour in DPV systems which are summarised as follows:

- **System size is the dominant risk factor.** In the showcase VIC event, 39% of >30 kVA systems tripped, versus 1 of 60 ≤30 kVA systems. Crossing the 30 kVA threshold increased odds of tripping by ~40× (logistic regression).
- **Distance and DNSP were not explanatory once size was considered.** Large systems tripped both near and far from the fault; proximity and DNSP membership offered limited predictive power.
- **Newer standard ≠ better real-world ride-through (yet) for systems >30 kVA.** Installations under AS/NZS 4777.2:2020 (incl. compliance improvements) did not show measurably better ride-through than 2016-era systems after controlling for size.
- **Brand fault logs confirm a voltage-driven mechanism (where available).** *Inverter Brand 5* devices showed near-instant Grid transient over-voltage followed by Grid power outage, aligning with the power-signal trip flags—valuable forensic insight. (Other brands lacked usable, timestamped logs.)
- **API fragmentation blocked cross-vendor learning.** Per-site keys, shallow retention windows and inconsistent timestamps prevented event-aligned analysis for several brands; a common logging framework is needed.
- **Dual-method detection is powerful.** Combining the 5-minute power-signal classifier with inverter fault logs improves classification accuracy and causal insight; the study operationalised both approaches.
- **Network/standard interactions observed.** Some AS/NZS 4777.2:2020 installations in *DNSP 2* and *DNSP 3* show higher trip/fault rates, while older AS/NZS 4777.1:2016 systems in *DNSP 3* exhibited better ride-through, pointing to potential commissioning/configuration differences.
- **Data limits to keep in mind.** 5-minute resolution can miss brief trips; some metadata and spatial precision gaps exist; brand fault-log access and timestamp integrity vary.

5.2 Data-specific challenges

5.2.1 Limits of the power-signal dataset

Several challenges should be considered when interpreting these results, including the below:

- **Temporal resolution (5-minute data).** Sub-5-minute trips can be missed or have their onset rounded to the nearest interval (±2.5 min). Very brief trip–reconnect cycles may appear as muted dips rather than clear zeros.
- **Algorithmic detection limits.** The trip classifier looks for sudden collapses in AC output toward zero. Partial trips (e.g., string-level events), mixed-brand sites, or per-inverter trips behind a site-level aggregate may be under-detected. Export limits/zero-export controllers, DOE-driven curtailment, battery charging, or site load changes can mask a true trip. Rapid cloud transients and PV clipping can mimic a drop if coincident with the event.
- **Metadata completeness.** Some sites lack AC ratings, orientation/tilt, commissioning standard, or IPD details. We inferred AC size from DC nameplate where required, which introduces uncertainty in capacity binning and can affect precision of size-based comparisons.
- **Spatial precision.** Coordinates are owner/integrator supplied and can be rounded (e.g., to 0.1°). This affects spatial joins, distance-to-event calculations, and DNSP boundary attribution – Especially for boundary-adjacent sites.

- **Event attribution.** Power drops are a proxy for tripping and can be confounded by shading, maintenance outages, unrelated feeder faults, or site-level switching. While the engine is tuned to minimise false positives, some ambiguity remains.
- **Sample size and imbalance.** Certain distance bins and DNSP slices contain few sites. Resulting rates have wide confidence intervals and should be treated as indicative, not definitive.
- **Device aggregation and ID mapping.** Some sites aggregate multiple inverters and/or brands. Without per-device traces, we cannot resolve intra-site heterogeneity in behaviour.
- **Timestamp and daylight saving.** Vendor portals use differing timestamps (local vs UTC) and may not apply DST consistently. After normalisation, residual misalignments are possible.
- **Availability bias.** The monitored fleet is not a random sample of all DPV (it skews to C&I sites with active monitoring). Outcomes may not fully generalise.

5.2.2 Fault-code retrieval: brand-specific hurdles

Collecting inverter error logs was markedly less uniform than collecting power data. Each manufacturer exposes a different web service with varying documentation, authentication, and data quality. Only *Inverter Brand 5* returned a complete, timestamped record for every queried device; other vendors exhibited one or more blocking issues that prevented reliable event-level analysis. Consequently, fault-code statistics in the main text are restricted to the *Inverter Brand 5* fleet; cross-brand trip detection relies on the power-signal algorithm.

The main limitations clustered into the following areas:

- **Historical depth and retention.** Several portals expose only live or short-window alerts (e.g., 7–30 days), with no backfill/bulk export – Making reconstruction of past events impossible.
- **Access control and throughput.** Paid tiers, per-device tokens, IP whitelisting, or human-approved org access create friction. Tight rate limits, throttling (HTTP 429), and pagination quirks impede high-volume pulls in narrow analysis windows.
- **Timestamp integrity and time zones.** Device clocks are not always Network Time Protocol (NTP)-synced. Logs may be in local time without time zone tags, apply Daylight Saving Time (DST) inconsistently, omit milliseconds, or arrive out of order – Complicating alignment to market/event time.
- **Identifier mapping.** Inconsistent mapping among site/plant/device IDs (including renamed or decommissioned devices, reused serials) introduces join errors without a robust, up-to-date mapping table.
- **Semantics and dictionaries.** Fault codes and severities vary by vendor and firmware. The same code label can indicate multiple mechanisms; some messages are localised (non-English); many alerts are transient or latched, producing duplicates without clear “end” markers.
- **Data integrity and stability.** Undocumented API changes, intermittent empty payloads, and maintenance outages reduce reliability. Some portals queue events and deliver them late, breaking strict event-time analysis.
- **Lack of push mechanisms.** Where webhooks³² are absent, polling is required—expensive under rate limits and prone to gaps during peak periods.

Because of these constraints, Section 4.2.2 presented fault-code analysis only for *Inverter Brand 5*, with detailed limitation per inverter brand further detailed under Table 9.

Table 9. Summary of brand-specific limitations encountered in the error-code querying process.

Inverter Brand	API / access status	Timestamp and retention	Fault-code payload	Practical limitations
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³² Webhooks are event-driven notifications that push data automatically when an event occurs, rather than requiring repeated polling.

Inverter Brand 1	One API key per site. Rate-limited	Queries allowed back one year	Two streams: profile (brand specific code IDs) and source (device errors), both returned	Insufficient data for event reconstruction
Inverter Brand 2	Requires profile-specific rights. Token tied to main account	Historical depth unconfirmed	Code availability unconfirmed due to access limitation.	Insufficient data for event reconstruction
Inverter Brand 3	Open REST endpoint. Single token for all sites	History capped at ~6-3 months, depending on underlying data management system.	Codes structured, but access window too short for event in focus.	Insufficient data for event reconstruction
Inverter Brand 4	One API key per site. Rate-limited	Status pushed every ~5 min at non-uniform times.	Returns inverter status, not granular fault codes	Timing offsets and lack of codes constituted insufficient data for event reconstruction
Inverter Brand 5	Open REST endpoint. Single API key for all sites. Rate-limited	Full second-level logs, but timestamps lack explicit time zone field	Rich payload. Code set varies by model, so model-level manual lookup required	Complete dataset (52 sites) used in Section 4.2.2

5.3 Recommendations

The following recommendations distil the study's findings into targeted, actionable measures for DNSPs, asset owners, standards bodies, and the broader industry.

1. Immediate operational actions (DNSPs / asset owners)

- **Continue targeted investigation of the >30 kVA fleet.** Medium and large-scale PV systems (>30 kVA) should remain a priority cohort for disturbance-response investigation, given their consistently higher observed trip rates in this study and in independent analyses by AEMO³³. Further targeted monitoring and validation is recommended before drawing firm conclusions at fleet scale.
- **Undertake focused data collection and site audits on >30 kVA systems.** Work with DNSPs, asset owners, and OEMs to expand datasets and conduct site-level audits on >30 kVA installations, including verification of inverter protection settings, and commissioning configurations.
- **Embed dual-evidence forensics in post-event reviews.** Pair the power-signal trip detector with inverter/API fault logs wherever available to confirm mechanism (e.g., transient Over Voltage → outage).
- **Adjust operational risk models.** Weight feeder risk by installed >30 kVA capacity, not proximity to transmission faults or DNSP boundary.

2. Standards, compliance & commissioning

- **Close the “paper-compliance vs performance” gap.** Given no clear ride-through improvement from AS/NZS 4777.2:2020 in this dataset, expand compliance verification to include field-proven settings and commissioning checks for IPD/inverter coordination.

3. Data & visibility (industry-wide)

- Investigate inverter fault logging capability via IEEE2030.5 and for incorporation into future Common Smart Inverter Profile – Australia (CSIP-AUS) with a focus on standardisation and harmonisation of responses. Define a minimum, interoperable fault-logging and access specification across inverter brands, including authentication models, data-retention depth, timestamp and time-zone handling, and, where feasible, a harmonised fault dictionary to enable consistent cross-vendor interpretation of

³³ AEMO, [Final Report – Trip of Moorabool – Sydenham 500 kV No. 1 and No. 2 lines on 13 February 2024](#), July 2025.

events. Investigate pathways to access this data with an initial focus on CSIP-AUS and identify any other standard dependencies.

- **Capture and store IPD settings.** Ensure connection/commissioning records include full IPD make/model and setpoints (OV/UV/ROCOF/Vector Shift/delays) and make them able to be queried for event forensics. (See examples of fields used in this study.)

4. Evidence base (short-cycle research & monitoring)

- **Broaden event sampling.** Add multiple disturbances across all NEM regions, including DNSP-level faults, to strengthen statistics and regional targeting.
- **Deep-dive IPD coordination.** Systematically test how specific IPD setpoints/delays co-act with inverter ride-through to identify robust, low-trip configurations for C&I PV.

6 Future research opportunities

The findings from this study highlight several avenues for further investigation that could materially improve the understanding, prediction, and mitigation of high tripping rates in >30 kVA distributed PV systems. Future research should focus on the following priority areas:

1. Expanded event and geographic sampling

This study was dominated by a small number of large-trip events, limiting statistical robustness for some analyses. Expanding the dataset to include multiple disturbance events across all NEM jurisdictions—and incorporating non-AEMO logged disturbances such as DNSP-level faults—would support DNSP and asset-owner learning, improving understanding of inverter error-flag behaviour under a wider range of local disturbance conditions, enable comparison across network contexts, and help refine event-response and diagnostics at the distribution level.

2. Impact of IPD device configurations

While IPD settings were collected for a subset of sites, the sample size was insufficient for definitive conclusions. Further research should evaluate how specific IPD protection thresholds, delays, and coordination with inverter protection behaviours, particularly for commercial rooftop and industrial PV systems.

3. Compliance monitoring and effectiveness of standards

At this stage, the analysis identified that performance of systems >30kVA did not necessarily improve following the revision to AS/NZS 4777 standards. Further investigation could determine whether non-compliance, implementation variability, or inherent standard limitations are responsible.

4. Enhanced, standardised fault-logging across manufacturers

A major limitation in this study was the lack of consistent, timestamped inverter fault logs across brands. Developing and trialling a standardised API specification—covering authentication, minimum retention depth, timestamp formatting, and a harmonised fault dictionary—would enable cross-vendor disturbance analysis. Pilot projects could evaluate the feasibility of embedding such requirements in other standards such as CSIP-Aus, or future AS/NZS 4777 revisions or DNSP connection standards.

By addressing these gaps, future studies can deliver both the technical depth and operational tools required to materially reduce disturbance-related PV loss, improving NEM stability under high-DER.

7 Conclusions

This study shows that disturbance-related DPV loss in this event is strongly associated with system scale, while the specific mechanisms that caused individual systems to trip remain unresolved. By pairing a five-minute power-signal classifier with inverter fault logs where available, we find that medium-scale systems (>30 kVA) were disproportionately prone to coincident disconnections, whereas straight-line distance to the initiating event and DNSP jurisdiction provided little explanatory power once size was accounted for. In the showcase event, 39% of >30 kVA systems tripped versus one of sixty ≤30 kVA systems; logistic regression indicates that crossing the 30 kVA threshold increased the odds of tripping by around 40 times. Where vendor fault logs were retrievable (notably Inverter Brand 5), the recorded events were voltage-related and temporally aligned with the power-signal detections, reinforcing the value of a dual-evidence approach for post-event reconstruction, even though the precise protection pathways could not be isolated.

The immediate operational implication is therefore one of prioritisation rather than diagnosis. Risk, as observed in this event, is concentrated in commercial-scale rooftop PV, meaning that size-led triage-focusing operational attention, follow-up, and data collection on >30 kVA fleets-offers a more efficient starting point than approaches that prioritise sites based on geographic proximity to the disturbance or DNSP boundaries. This does not imply that distance or network location is irrelevant in general, but rather that, for this event, they did not reliably discriminate between tripped and non-tripped systems once capacity was considered.

Importantly, comparisons of IPD settings, standards, and DNSP distributions across both analytical approaches did not identify a single protection parameter, standard version, or commissioning rule-of-thumb that consistently separated tripped from non-tripped sites. While some tripped systems exhibited higher over-voltage thresholds or additional protection elements (e.g. OV2), counterexamples were common, and frequency- or ROCOF-based explanations were not supported by the disturbance characteristics observed in this dataset. As such, the results should not be interpreted as evidence that particular IPD values or protection settings caused the observed tripping; rather, they highlight the current limits of inference given available data.

A second, system-wide lesson concerns data and visibility. Diagnostic confidence improves materially when power-signal evidence can be corroborated with timestamped, device-level fault logs. In this study, that capability was uneven. Fragmented OEM interfaces, limited log retention, inconsistent timestamps, and non-harmonised fault code definitions constrained cross-vendor learning and, for several fleets, required reliance on power-signal detection alone. Establishing a minimum cross-vendor logging baseline, such as NTP-synchronised clocks, UTC timestamps with offsets, ≥90-day retention, stable versioned APIs, bulk export or webhook access, consistent device identifiers, and a shared fault-code taxonomy, would substantially improve the industry's ability to interpret future disturbance events.

These findings should be read alongside the study's constraints. Five-minute resolution can miss short trip-reconnect cycles; some site metadata required inference; spatial coordinates carried rounding uncertainty near DNSP boundaries; and inverter fault-log access was limited to a subset of brands and sites. We mitigated the metadata issues through conservative classification, sensitivity checks, and explicit reporting of sample sizes, but they remain important when considering generalisation.

Overall, this study does not yet explain why individual systems tripped, but it does identify where learning efforts should be focused and what must change to enable stronger conclusions in future events. In the near term, prioritising >30 kVA fleets for enhanced monitoring, post-event review, and data access agreements will

yield the greatest improvement in situational awareness. Embedding dual-evidence forensics as standard practice and adopting a national minimum logging specification are necessary precursors to establishing causal links between disturbances, protection behaviour, and inverter responses. Taken together, these steps will not immediately eliminate coincident trips, but they will materially improve event reconstruction, support robust future analysis, and create the conditions required to reduce disturbance-related PV loss as DER penetration continues to increase across the NEM.

8 Appendices

8.1 Sites with fault codes logged but unidentified by the Diagno tripping-detection engine

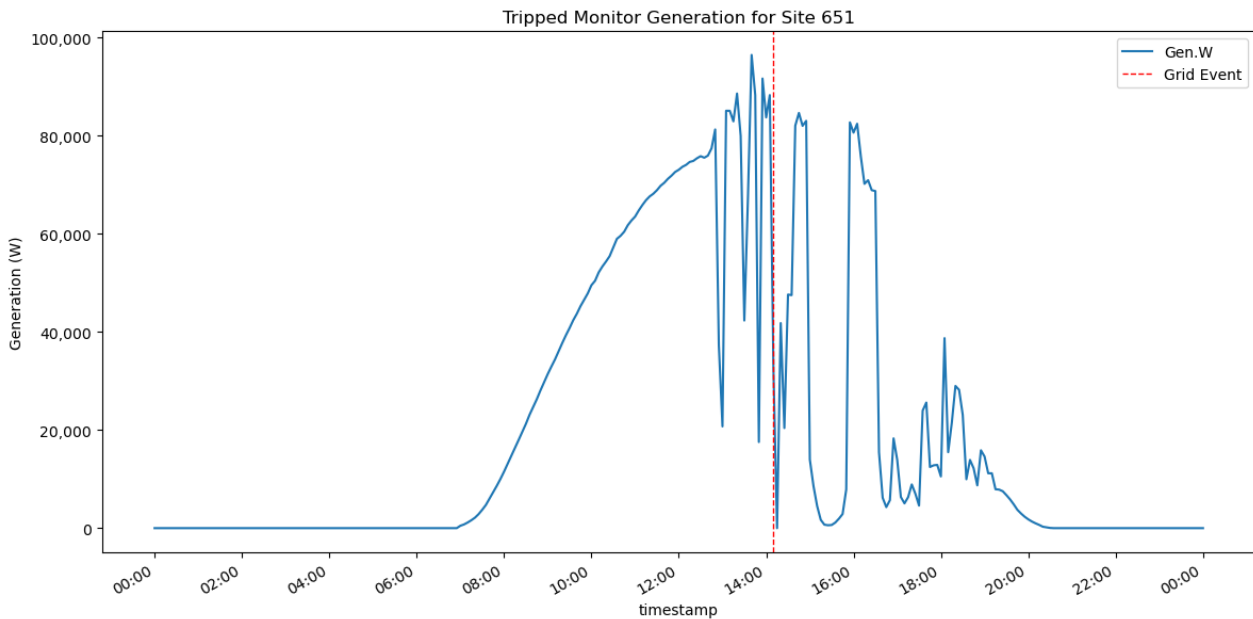


Figure 19. Example of a tripping signature captured by the power-signal algorithm (The blue curve shows 5-minute AC generation for one inverter on the day of a grid-side event; and the red dashed line marks the grid disturbance. A sharp collapse from full output to zero immediately after the disturbance, followed by intermittent recovery, satisfies the algorithm’s “zero-trip” criterion and flags the site as tripped).

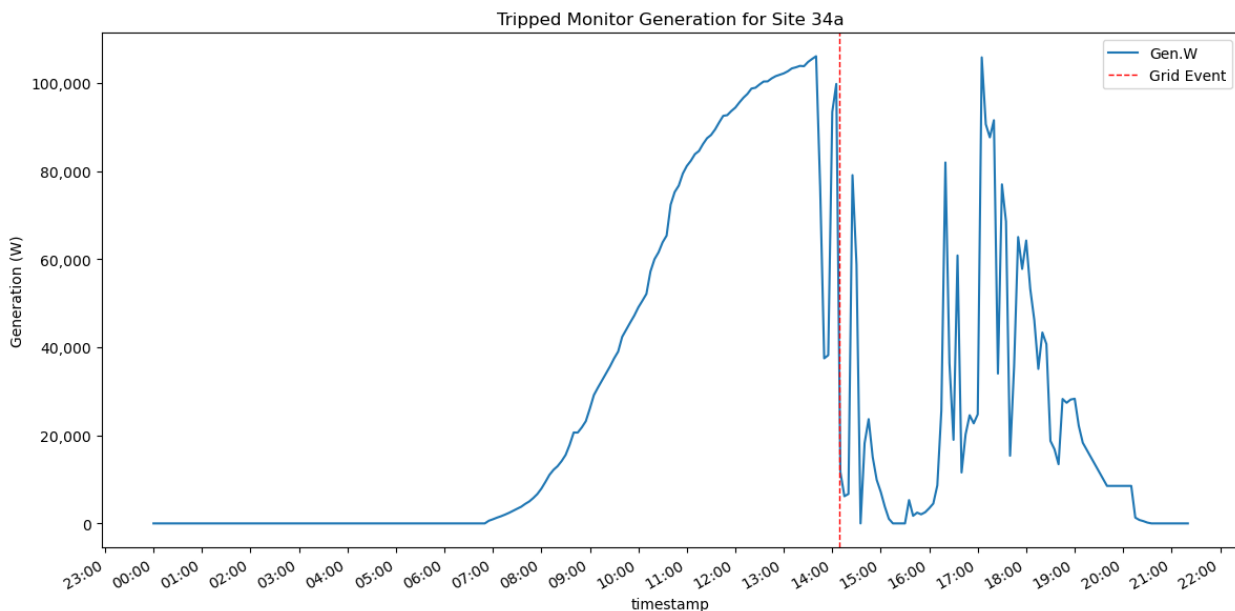


Figure 20. Example of an instance of an inverter fault logged where generation dropped sharply but not to zero in the two 5-minute intervals immediately after the grid disturbance (see section 4.2). Although the inverter recorded a fault, the partial drop meant the event did not meet the algorithm’s “zero-trip” criterion.

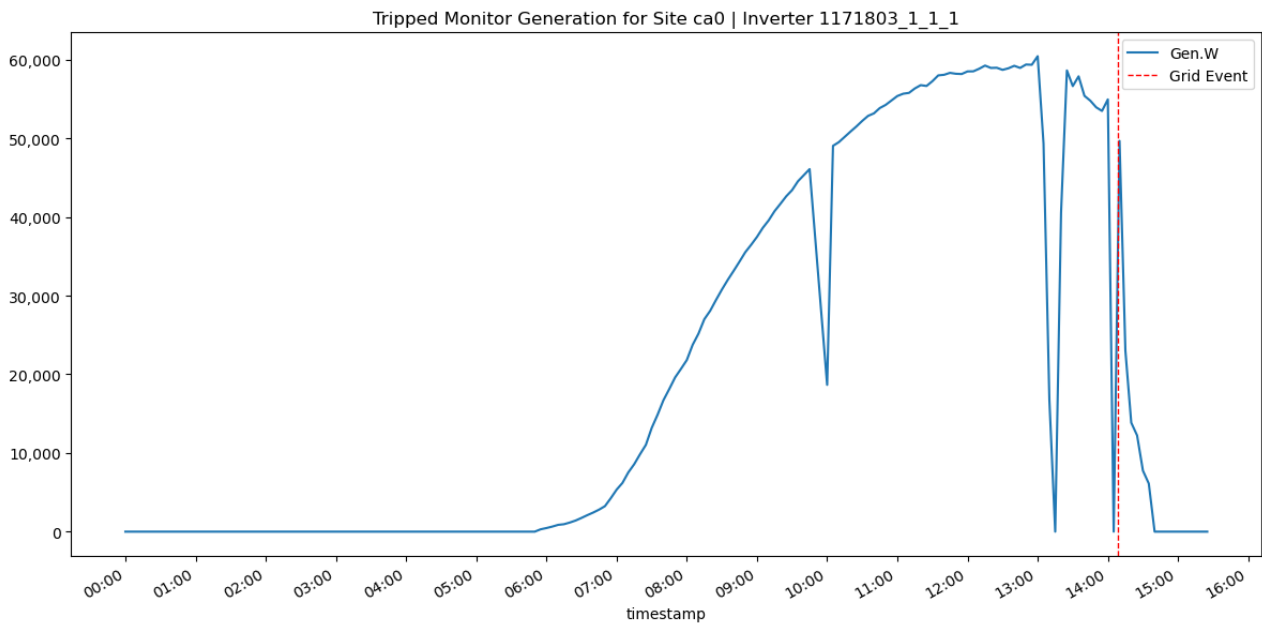


Figure 21. Second example of an instance of an inverter fault logged where generation dropped sharply but not to zero in the two 5-minute intervals immediately after the grid disturbance (see section 4.2). Although the inverter recorded a fault, the partial drop meant the event did not meet the algorithm’s “zero-trip” criterion.

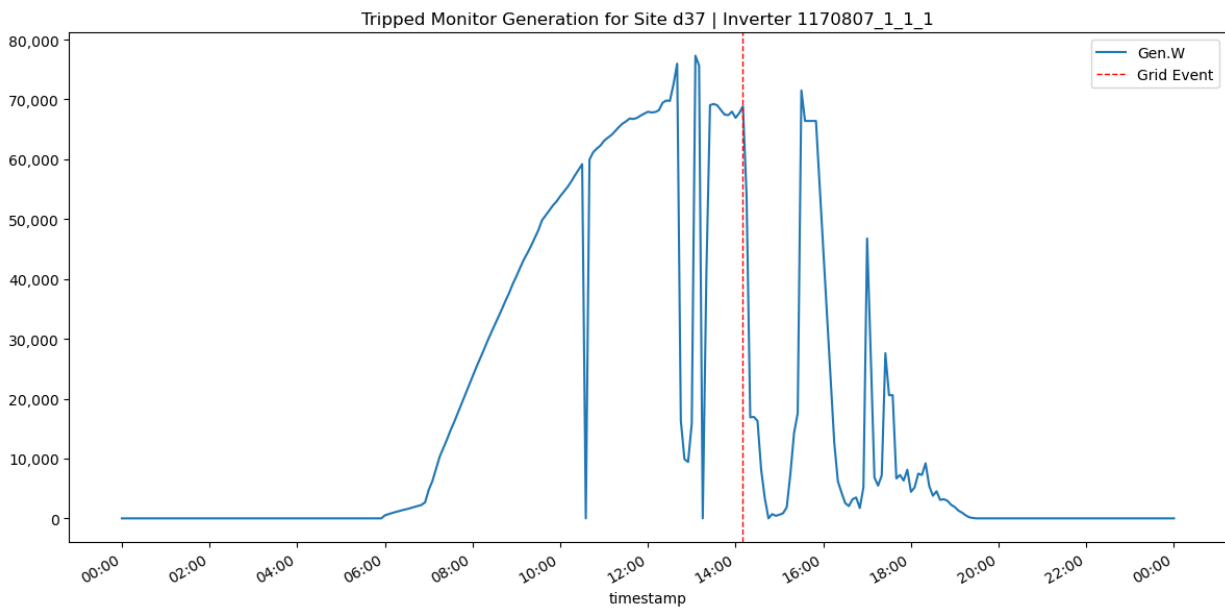


Figure 22. Third example of an instance of an inverter fault logged where generation dropped sharply but not to zero in the two 5-minute intervals immediately after the grid disturbance (see section 4.2). Although the inverter recorded a fault, the partial drop meant the event did not meet the algorithm’s “zero-trip” criterion.

8.2 Applicable standards

Table 10. Applicable AS/NZ4777.2 Inverter standard in accordance with their publication and enforcement date

Standard	Publication date	Enforcement date	Comments
AS/NZS4777.3:2005	20 May 2005	20 May 2006	First version of the Standard.
AS/NZS4777.2:2015	9 October 2015	9 October 2016	<p>A trip delay time was specified for under-voltage disturbances (ride-through), however not captured in testing. Volt-var and Volt-watt capability included but listed as <i>optional</i>. Defined frequency and demand response modes</p> <p><i>Note: Between 2016 and 2020 DNSPs progressively introduced their own volt-var and volt-watt settings.</i></p>
AS/NZS4777.2:2020	18 December 2020	18 December 2021	<p>Ride-through capability significantly enhanced and implemented – include ROCOF, Phase angle jump, and more comprehensively under and over voltage requirements. Volt-var and volt-watt were made mandatory, and settings optimised. Improved accuracy and stability of measurement systems to improve their performance characteristics (including for ride-through). More explicitly defined scope to include EVs in V2G. Aligned requirements by regions within Australia:</p> <ul style="list-style-type: none"> • Australia A: Mainland NEM (NSW, Vic, Qld, SA) - large, interconnected power system • Australia B: WA - small, interconnected power systems • Australia C: Tas and Horizon Power - isolated or remote power systems. <p><i>Note: Following its implementation, AEMO identified poor compliance to the AS/NZS4777.2:2020 Grid codes in early 2022. In collaboration with industry (specifically OEMs and installers), it is anticipated that compliance to grid code settings (and therefore in many cases ride-through) improved from about April 2023.</i></p>

Table 11 Applicable AS/NZ4777.1 Installation standard in accordance with their publication and enforcement date

Standard	Publication date	Enforcement date	Comments
AS/NZS4777.3:2005	20 May 2005	20 May 2006	First version of the Standard.
AS/NZS4777.1:2016	30 September 2016	30 March 2017	Includes requirements for a Central Protection Device (CPD) to be included in the installation for systems >30 kVA.
AS/NZS4777.1:2024	23 August 2024	23 February 2025	Made changes to the Integrated Protection Device (IPD previously CPD), increasing the threshold for systems to include an IPD from 30kVA up to 200kVA. We are hoping to see systems >30kVA have improved ride-through responses from this date.

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