



Protection Relay Testing Guide



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About This Guide

Protection relay testing proves that the relays protecting a power system will trip the right circuit breaker, in the right time, for a fault in their zone, and stay stable for everything else. A test set injects currents and voltages that represent faults and times the relay's response. This guide covers the test methods, safe isolation, how often relays are tested and how to judge a result.

What Relay Testing Is

Injecting currents and voltages that represent faults into a protection relay, or through its CTs, and proving that every enabled element picks up, trips and resets at its setting and operating time.

When It Is Used

At commissioning, at the routine interval in the asset owner's plan, after a setting change, firmware update or repair, and after the relay has operated.

Why It Matters

A relay sits idle for years and operates only when a fault occurs. A failed input, output or setting stays hidden until that moment. SEL reports its self-tests detect about 85% of component failures (2014); testing covers what self-supervision cannot.

Guide at a Glance

Methods

Secondary injection, primary injection, trip and scheme tests, end-to-end tests.

Standards

AS/NZS 60255.1:2025 and the IEC 60255 functional parts for the relays; the asset owner's testing standard for the test.

Example Interval

4 years unmonitored, 6 years monitored microprocessor relays (USB R FIST 3-8).

Judged Against

The approved settings and the assigned error the manufacturer declares, allowing for test set uncertainty (AS/NZS 60255.1, cl 6.5.2.1).

Test Sets

OMICRON CMC 356 and CMC 500, CPC 100 for primary injection.

Need relays tested, or the test set to do it? Megavar tests protection schemes across Australia and hires every instrument in this guide.



Why Test Protection Relays?

Protection Relay Testing in Four Numbers

85%

Component failures detected by SEL relay self-tests (SEL, 2014)

1 year

First routine test after commissioning (USBR FIST 3-8)

4 years

Interval for unmonitored microprocessor relays (USBR FIST 3-8)

6 years

Interval for monitored microprocessor relays (USBR FIST 3-8)

Why Relays Must Be Tested

A Hidden Failure

A protection relay can sit idle for years and operate only when a fault occurs. A failed measuring input, output contact or wrong setting stays hidden until that moment unless a test finds it first.

Two Ways to Fail

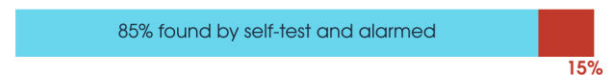
A relay can fail to trip for a fault in its zone, or trip when it should not. TasNetworks' testing standard treats tests that prove non-operation as being as significant as tests that prove operation.

What Self-Tests Miss

Numerical relays supervise their own processor and memory. SEL reports that its self-tests detect about 85% of component failures; analogue inputs, logic inputs and output contacts are not covered, and those are what routine testing targets.

What Self-Tests Cannot See

Relay component failures, by how they are found (SEL)



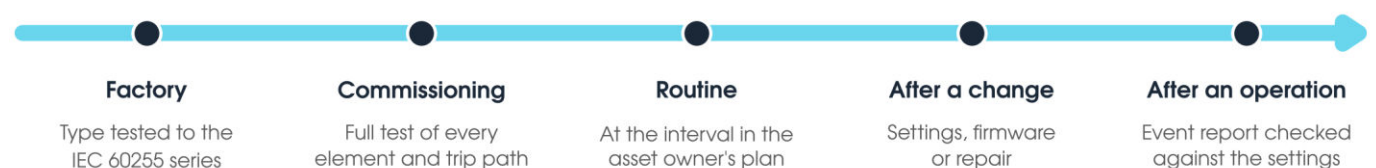
Not covered by self-test, so left to testing:

- Analogue current and voltage inputs
- Logic (binary) inputs
- Output contacts

Source: SEL, Periodic Maintenance Testing of Protective Relays, 2014

SEL reports about 15% of component failures are not detected by its self-tests; testing covers the inputs and outputs.

When to Test



Where Is It Used?

Protection Functions Tested

Protection function	Device no.	What the test proves
Overcurrent and earth fault	50/51	Pickup, and inverse-time operating times at several fault levels
Directional overcurrent	67	Forward and reverse operation for the set characteristic angle
Distance	21	Zone reaches and zone times on the impedance plane
Transformer differential	87T	Pickup, bias slope, and stability for through faults
Busbar differential	87B	Stability for external faults, and a trip of every breaker in the zone
Under and over voltage	27/59	Pickup and operating time at the set voltages
Frequency	81	Pickup and operating time at the set frequencies
Breaker failure	50BF	Initiation, timers and backup trips to adjacent breakers
Auto-reclose and check synchronising	79/25	Reclose sequence and dead times; synchronising limits

The Five Requirements

Dependability

The relay trips for every fault in its zone.

Security

It stays stable for load, inrush and out-of-zone faults, apart from its coordinated backup duty.

Selectivity

The breakers the scheme requires open, so the smallest area is lost.

Speed

The fault clears before equipment is damaged or the system loses stability.

Sensitivity

The relay detects the minimum fault current its zone can produce.

Standards That Apply

AS/NZS 60255.1:2025

Common requirements, adopting IEC 60255-1:2022 (MOD). The measured error must be within the assigned error the manufacturer declares, allowing for test set uncertainty (cl 6.5.2.1). Pickup and operate time are verified from five consecutive measurements (cl 6.5.2.2 to 6.5.2.4).

IEC 60255 Functional Parts

-151 over and under current, -121 distance, -187-1 differential for motors, generators and transformers, -127 over and under voltage, -181 frequency, -149 thermal.

The Asset Owner's Standard

Sets what is tested and the acceptance criteria, as TasNetworks' Secondary Equipment Testing Standard does for its network.

Good to Know

A result is judged against the accuracy the manufacturer declares under the relevant IEC 60255 part. Take it from the relay manual, not from memory.

Instrument Transformer Classes the Relay Depends On

Class	Limit	Source
CT 5P, 5PR	Ratio error $\pm 1\%$ and phase displacement ± 60 minutes at rated current; composite error 5% at the rated accuracy limit current	AS 61869.2, Table 205
CT 10P, 10PR	Ratio error $\pm 3\%$ at rated current; composite error 10% at the rated accuracy limit current. PR cores limit remanence to 10%	AS 61869.2, Table 205, cl 5.6.202.3
CT PX, PXR	Specified by knee point e.m.f., exciting current at the knee point and burden; turns ratio error 0.25% (PX) or 1% (PXR). This 10%/50% knee point reads about 20 to 25% higher than the IEEE 45° knee point	AS 61869.2, cl 5.6.202.4; IEEE C57.13, cl 6.10.2 and C37.110, cl 4.3.2
VT 3P, 6P	Voltage error $\pm 3\%$ or $\pm 6\%$, phase displacement ± 120 or ± 240 minutes, from 5% of rated voltage to the rated voltage factor	AS 61869.3, Table 302

How Does It Work?

Secondary Injection

What It Is

A relay test set injects currents and voltages straight into the relay through the test block, in place of the CT and VT secondaries, and times the trip contact.

What It Proves

Every enabled element picks up, trips and resets at its setting and operating time.

Built From the Settings

Megavar records results in OMICRON Test Universe and compares them with the approved protection settings, the manufacturer's specification and the relevant standards.

Primary Injection and Scheme Tests

Primary Injection

Current is passed through the CT primary, for example with an OMICRON CPC 100, proving CT ratio, polarity and the wiring to the relay. Secondary injection cannot see a crossed phase because it bypasses the CT. IEEE C57.13.1-2017 covers field testing of relaying CTs.

Trip and Functional Tests

Every trip path is proven to the right breaker trip coil, with intertrips, breaker fail and alarms.

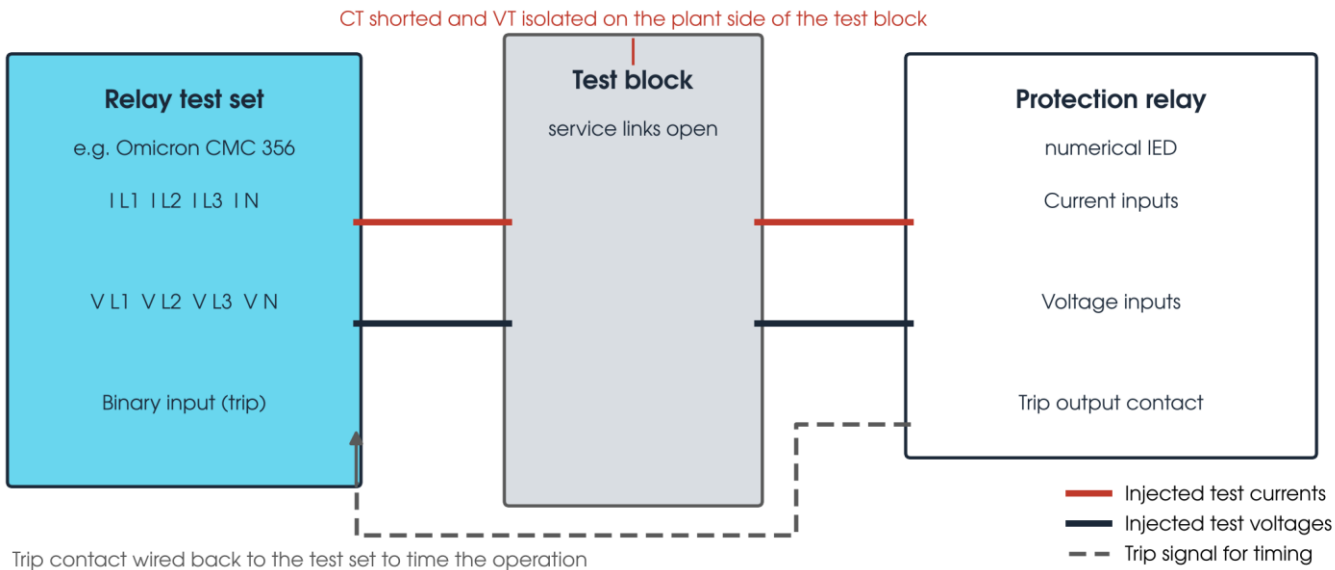
End-to-End Tests

Line schemes are tested from both ends at once, with the test sets time-synchronised by GPS, for example with the OMICRON CMGPS 588.

Good to Know

TasNetworks' testing standard states that overall, end-to-end testing is superior to piecemeal testing. Where piecemeal tests are unavoidable, they must overlap.

Secondary Injection Connection



Secondary injection through the test block. The test set supplies the currents and voltages and times the trip contact; the CTs and VTs are isolated on the plant side.

Primary or Secondary Injection?

	Secondary injection	Primary injection
What it proves	Every enabled element at its setting and time	Ratio, polarity and wiring to the relay; see the CT testing guide
What it cannot see	A crossed CT phase or a CT on the wrong relay	CT performance at fault level: it checks ratio at the test current

How Do I Set Up Safely?

Permits, Isolation and Checklists

1 Permit

Work on equipment connected to in-service circuits only under the asset owner's safety rules and the access permit.

2 Plan the Isolations

List every isolation on a pre-prepared alteration and isolation checklist: protection trips, protection signalling, CT secondaries and breaker fail initiations (TasNetworks).

3 Isolate at the Test Block

Open trip, intertrip and breaker fail links before injecting, so the test cannot trip a live breaker or another bay.

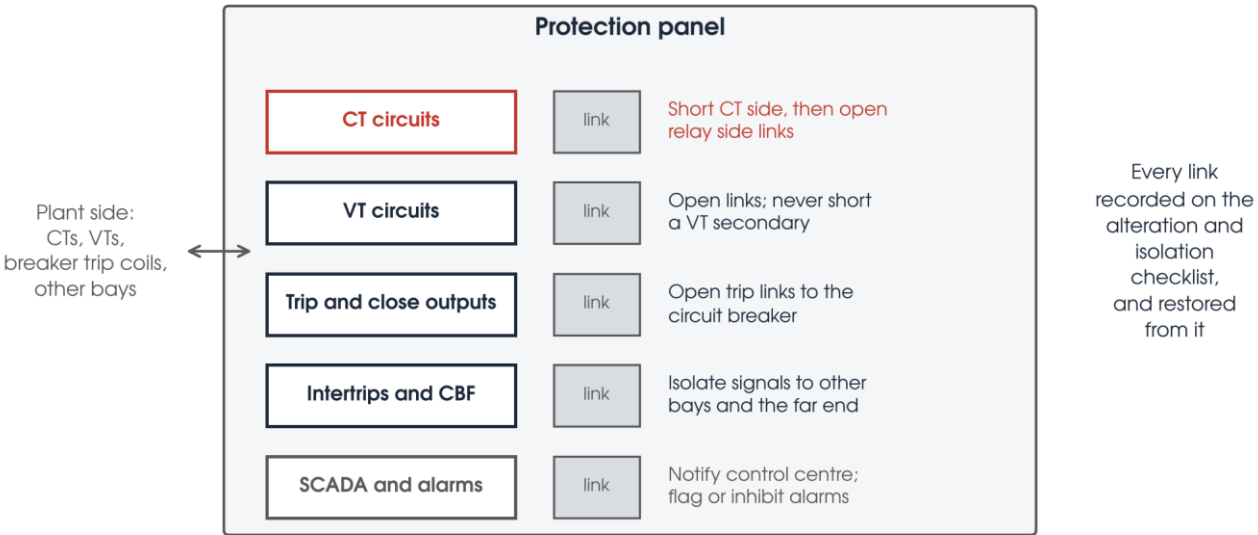
4 Restore From the Checklist

Restore every link from the same checklist, and include the signed checklist in the test report.

Who Should Test

AS 2067 cl 2.1.1 requires installation, testing, commissioning and maintenance to be carried out by qualified and competent personnel; who is authorised is set by the asset owner's rules.

Isolation at the Protection Panel



Each circuit is isolated at its test block link and recorded on the checklist. CT circuits are shorted before the relay side is opened.

Important

This guide describes general practice for competent protection testing personnel. It is not a work procedure. Work under the asset owner's safety rules, the access permit and a site-specific safe work method statement. Manufacturer and asset owner criteria take precedence over the general guidance here.

CT and VT Hazards

Never Open-Circuit a CT

An open-circuited CT secondary in service or during injection can develop lethal voltages, damage insulation and cause a flashover (TasNetworks).

Never Back-Energise a VT

Injecting into a VT secondary that is still connected can energise the primary at full voltage.

Never Short a VT Secondary

A short on an energised VT secondary drives a damaging current through the winding.

Revenue Metering

Contact the metering provider before working on instrument transformer circuits shared with revenue metering.

How Do I Make the Measurement?

Seven Steps



Steps 1 to 4

1 Plan and Prepare Forms

Define pass and fail criteria for each test and prepare the test forms in advance. TasNetworks requires its forms approved before testing starts.

2 Isolate to the Checklist

Make every isolation on the checklist and confirm it before any injection.

3 Wiring and Insulation

Insulation and continuity tests, with electronic devices disconnected, come before any energisation test.

4 Secondary Injection

Test every enabled element at its setting: pickup, drop-off and operating time.

Steps 5 to 7

5 Primary Injection

Prove CT ratio, polarity and the wiring to the relay.

6 Trip and Scheme Tests

Under the agreed outage, trip the breaker from each element and prove intertrips, breaker fail and alarms.

7 Restore and On-Load Checks

Restore from the checklist. After livening, confirm CT and VT polarity and relay direction with load current.

Good to Know

On a routine test, record the first injection result before adjusting anything. It shows how the relay would have behaved in a real fault (TasNetworks).

Common Mistakes

Testing From a Template

Elements the template did not list go untested.

Settings Not Read From the Relay

The applied settings may differ from the setting study.

Trip Links Left Closed

A live breaker or another bay is tripped.

Only Proving Operation

Stability for external faults is never proved.

More Common Mistakes

CT Secondary Open-Circuited

Lethal voltage and possible CT damage.

As-Found Result Lost

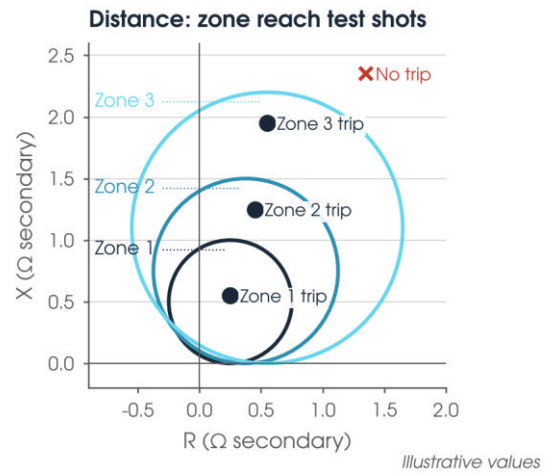
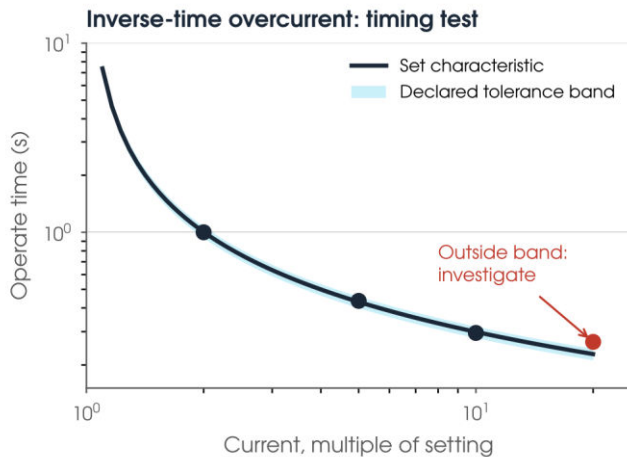
Adjusting before recording hides the drift since the last test.

Isolations Not Restored From the Checklist

A trip or signal is left isolated when the bay returns to service.

How Do I Read the Result?

Timing and Zone Reach Results



One timing point sits outside the declared tolerance band and needs investigation. Each distance shot tripped in the zone it was placed in, and the shot outside zone 3 did not trip.

Comparing the Result

Against the Settings

Compare with the approved setting file, using the settings printed from the relay.

Against the Tolerance

Use the assigned error the relay manual declares for that element, allowing for test set uncertainty (AS/NZS 60255.1, cl 6.5.2.1). Pickup and operate time are verified from five consecutive measurements (cl 6.5.2.2 to 6.5.2.4).

Against Last Time

Compare as-found results with the previous test. A relay starting to drift shows here first (EPRI NP-7216).

Against the Event Record

After an operation, check the event report against the settings and confirm inputs and outputs operated (SEL, 2014).

What a Bad Result Looks Like

Pickup Outside Tolerance

Check the applied setting, then the input and the test set.

Operate Time Outside the Band

Check the curve type and time multiplier.

Trip in the Wrong Zone

A reach or zone timer setting, or a CT or VT input error.

Trip Contact Did Not Close

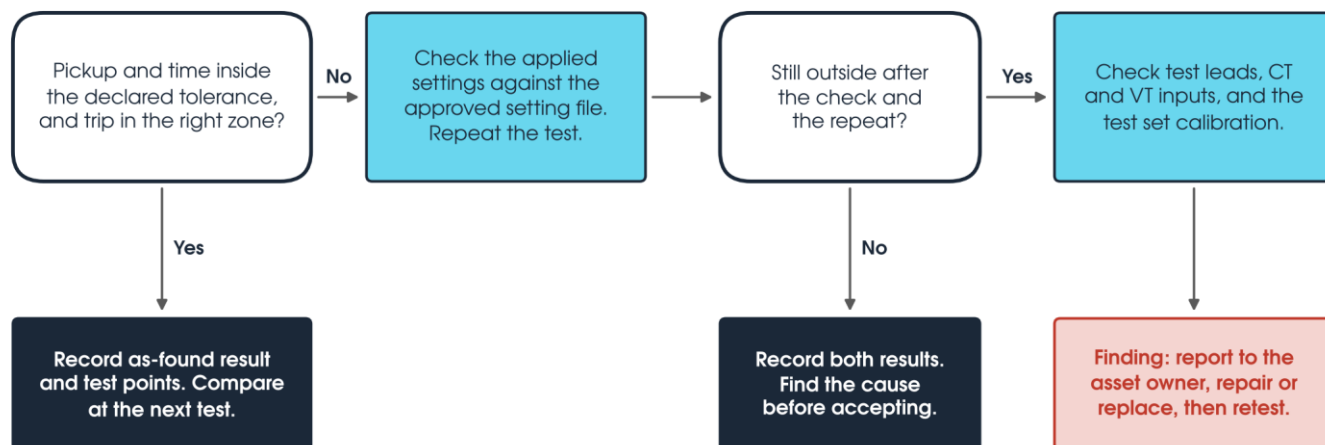
An output contact or wiring fault that self-test may not see.

Unstable for a Through Fault

Differential CT ratio, polarity or vector group error.

Is My Result OK?

Decision Path



Testing After a Change

A Limited Setting Change

Testing can be limited to the affected element when the change is limited in scope and all settings are verified correct afterwards (USBR FIST 3-8).

Firmware, Repair or Logic

Test the whole relay after a firmware update, repair, enabling or disabling a function, or a logic change (USBR FIST 3-8).

After an Operation

Analyse the event report and verify the inputs and output contacts that operated (SEL, 2014).

What to Report

Equipment Tested

Make, model, firmware revision, serial number and the asset owner's identification code.

Settings Applied

Listed, or referenced to the settings record by date and file number.

Test Equipment

Manufacturer, type, serial number and calibration date of each instrument used for each test.

Readings and Interpretation

Every reading, with the calculation and comment showing the equipment is or is not fit for service.

Defects and Isolations

Defects and outstanding actions, and the signed isolation checklist (TasNetworks).

How Often Should Protection Relays Be Tested?

Published Example Intervals

Relay technology	Functional test interval	Source
Electromechanical	Every year in harsh conditions; every 2 years in controlled environments	USBR FIST 3-8, citing NFPA 70B
Solid-state (static)	Every 2 years	USBR FIST 3-8, citing NFPA 70B
Microprocessor, unmonitored	Every 4 years	USBR FIST 3-8
Microprocessor, monitored	Every 6 years	USBR FIST 3-8
Microprocessor, self-test alarm monitored	For example once every ten years, on inputs, outputs and measuring	SEL, 2014
All types	1 year after commissioning, and after setting changes, repairs or firmware updates	USBR FIST 3-8

In Australia the interval is set by the asset owner. TasNetworks, for example, sets routine intervals in its asset management plan. The figures above are published examples, not Australian requirements; FIST 3-8 also verifies inputs and outputs every 2 years.

Recommended Solutions

Instrument	Capability	Best used for
OMICRON CMC 356	Six current and four voltage outputs	Secondary injection of overcurrent, distance and differential relays
OMICRON CMC 500 with IEDScout	Multiphase test set with IEDScout	IEC 61850 GOOSE testing, and Sampled Values as an option
OMICRON CMGPS 588	GPS time synchronisation	End-to-end tests with synchronised test sets
OMICRON CPC 100	Up to 800 A	Primary injection, CT ratio and polarity
Megger SVERKER 760	Single phase, up to 100 A or 250 V	Overcurrent, voltage and frequency relays
Schneider VAP6	VIP relay tester	Merlin Gerin VIP relays
OMICRON CMLIB REF6xx	Sensor input adapter	ABB REF6xx relays with sensor inputs

Every instrument is available calibrated, with leads, from Hobart, Launceston, Adelaide and Newcastle: [relay testing equipment hire](#).

Frequently Asked Questions

Common Questions

How often should protection relays be tested?

The asset owner's maintenance plan sets it. USBR FIST 3-8 gives functional tests every 4 years for unmonitored and 6 years for monitored microprocessor relays, and 1 to 2 years for older types.

What is the IEC standard for protection relay testing?

The IEC 60255 series. Part 1, common requirements, is adopted in Australia as AS/NZS 60255.1:2025; the functional parts include -151 overcurrent and -121 distance.

How is relay testing done?

By secondary injection of every enabled element, primary injection through the CTs, trip and scheme tests, and end-to-end tests on line schemes.

What are the basic requirements of protective relays?

Dependability, security, selectivity, speed and sensitivity.

Standards and References

AS/NZS 60255.1:2025, Measuring relays and protection equipment, Part 1: Common requirements (IEC 60255-1:2022 MOD).

IEC 60255 functional Parts 121, 127, 149, 151, 181 and 187-1, Measuring relays and protection equipment.

AS 61869.2:2021 (Amd 1, 2022) and AS 61869.3:2021, Instrument transformers, current and voltage transformers.

AS 2067:2016, Substations and high voltage installations exceeding 1 kV a.c.

IEEE C57.13-2016, C57.13.1-2017 and C37.110-2023, Instrument transformer requirements, field testing of relaying CTs, and CT application for protective relaying.

US Bureau of Reclamation, FIST 3-8, Operation, Maintenance, and Field Test Procedures for Protective Relays and Associated Circuits, 2011 (revised 2021).

SEL, Recommendations on Periodic Maintenance Testing of Protective Relays, 2014.

TasNetworks, Secondary Equipment Testing Standard, 2021.

EPRI NP-7216, Protective Relay Maintenance Application Guide, 1993.

OMICRON, IEC 61850 Introduction and Testing Solutions, 2026; Diagnostic Testing of Instrument Transformers, 2025.

NFPA 70B, as cited in USBR FIST 3-8.

More Questions

What is the best way to test a relay?

Test from the relay's own settings with automated software, then prove the CTs by primary injection and every trip path to the breaker.

What is the difference between primary and secondary current injection testing?

Secondary injection tests the relay; primary injection also proves the CT ratio, polarity and wiring.

Can a relay be tested without tripping the breaker?

Yes, by opening the trip links at the test block. The trip paths are then proven separately.

Does Megavar test IEC 61850 schemes?

Yes. Megavar verifies scheme logic including IEC 61850 GOOSE messaging. Call 1300 730 499.

Hire or Have It Tested

Have It Tested

Megavar's engineers carry out [protection relay testing](#) and [substation commissioning](#) from 11 kV distribution to 500 kV transmission.

Next Step

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Testing: service@megavar.com.au



Speak to our team today

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