Protection of High Voltage Plant

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Endeavour Energy

POWER together

Revision History

This standard supersedes amendment 2.

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Document Control

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Contents

1 Scope

This Company Standard details the electrical protection requirements for high voltage plant on the Endeavour Energy network.

The purpose of this network standard is to outline the requirements for the planning, design, and operation of the Company's high voltage plant protection systems to achieve the requirements and objectives of Company Policy 9.2.2 – Network Protection.

This network standard applies to Endeavour Energy's high voltage protection systems and specifically applies to the items listed below:

- Transmission feeders (33 kV, 66 kV and 132 kV)
- Transformers (high voltage side operating at 33 kV, 66 kV and 132 kV)
- Busbars (all voltages within zone and transmission substations)
- Capacitor banks (all voltages within zone and transmission substations)
- Distribution feeders (operating at 11 kV and 22 kV)
- Distribution transformers (high voltage side operating at 11 kV and 22 kV)
- Underfrequency load shedding
- Instrument transformer standard performance specifications

Requirements for high voltage customer installations and embedded generator connections are not included in this standard. These aspects are covered separately in the following standards:

- Protection Design Instruction PDI 4005 – Protection of high voltage customer installations
- Protection Design Instruction PDI 5000 – Protection of embedded generation systems

2 References

Internal References
Company Policy 9.1.2 – Reliability Principles
Company Policy 9.2.2 – Network Protection
Company Policy 9.2.5 – Network Asset Design
Company Policy 9.2.10 – Network Asset Ratings
Company Procedure GAM 0001 – Network Standards Framework: Preparation and Amendment of Network Standards
Branch Procedure TBC 0004 – Secondary Systems design process
Branch Procedure NCB 0642 – Protection Withdrawal Authority (PWA)
Equipment Technical Specification ETS 0085 – Battery systems
Mains Construction Instruction MCI 0005 – Overhead distribution construction standards manual (Section 8) – Substations, regulators, reclosers & other equipment
Mains Construction Instruction MCI 0006 – Underground distribution: construction standards manual (Section 7) – Substation & Switching Stations
Protection Design Instruction PDI 5000 – Protection of embedded generation systems
Substation Design Instruction SDI 501 – Network Configuration

Substation Design Instruction SDI 513 – Substation batteries and battery chargers
Substation Design Instruction SDI 526 – Design of substation secondary systems

External References
Electricity Supply Act 1995 (NSW)
Electricity Supply (Safety and Network Management) Regulation 2014
Work Health and Safety Act 2011 (NSW)
Work Health and Safety Regulation 2017 (NSW)
National Electricity Rules (NER)
AS 2067:2016 – Substations and high voltage installations exceeding 1 kV a.c.
Australian Standard AS 60044.1-2007 (R2016): Instrument Transformers – Current Transformers (Superseded)
Australian Standard AS 60044.2-2007 (R2016): Instrument Transformers – Inductive voltage Transformers (Superseded)
Australian Standard 1675-1986 Current Transformers – Measurement and Protection (Superseded)
ENA DOC 001-2008 – National Electricity Safety Code
ENA DOC 018-2015 – Guideline for the Fire Protection of Electricity Substations
IEC 60909-0:2016 - Short-circuit currents in three-phase a.c. systems, Part 0: Calculation of currents
AS 61869.1:2021 – Instrument transformers: General requirements
AS 61869.2:2021 – Instrument transformers: Additional requirements for current transformers
AS 61869.3:2021 – Instrument transformers: Additional requirements for inductive voltage transformers
AS 61869.5:2021 – Instrument transformers: Additional requirements for capacitor voltage transformers
IEEE Standard C37.2:2008 - Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations
IEEE Standard C37.99:2012 - IEEE Guide for the Protection of Shunt Capacitor Banks
IEEE C37.110:2007 - IEEE Guide for Application of Current Transformers used for Protective Relaying Purposes.
Service and installation rules of NSW - NSW Division of Resources & Energy, Department of Industry, Skills & Regional Development
ENA National Electricity Network Safety Code (Doc 01-2008)
Network Management Plan December 2013 Review

3 Definitions and Abbreviations

The following definitions and abbreviations are used within this document. A more comprehensive list of protection terminology has been included in the Appendix.

Abbreviation	Meaning
Base rating (transformer)	The transformer rating with natural cooling only (ONAN).
Capacitor element	Each individual capacitor within a can, that is, two electrodes separated by a dielectric.
Capacitor unit (can)	A self-contained assembly of multiple capacitor elements, often in series and parallel combinations.
CB	Circuit breaker
CB Fail	Circuit breaker failure
CT	Current Transformer
EF	Earth fault
IDMT	Inverse definite minimum time (overcurrent curve characteristic)
Instantaneous	A protection with no intentionally set time delay (there will be an actual time delay dependent on the detection and operating time of the relay).
NER	National Electricity Rules
OC	Overcurrent
OHEW	An overhead earth wire
ONAN	Oil Natural, Air Natural (cooling)
OPGW	An overhead earth wire which contains optical fibres for communications.
OTI	Oil temperature indicator
Practicable	Reasonably able to be done, giving regards to the circumstances. It is implied that to be practicable, it also needs to be cost effective.
PU	Pickup
PWA	Protection withdrawal authority
REF	Restricted earth fault
SCADA	Supervisory Control and Data Acquisition (control systems)
SEF	Sensitive earth fault
SIR	Source Impedance Ratio
TOBAN	Total Fire Ban
VT	Voltage transformer
WTI	Winding temperature indicator

UFLS	Underfrequency load shedding

4 Application

4.1 General

This Standard is applicable to the planning, design, and operation of high voltage protection systems. The design requirements of this standard must also be applied to existing protection systems when refurbishment takes place if practicable.

Designs must be conducted in accordance with Branch Procedure TBC 0004 – Protection design process.

4.2 Operations

The design requirements specified in this standard also set the standard of protection required for general operations. A lesser standard of protection may be acceptable in the case of infrequent planned and unplanned situations to maintain reliability of supply. Examples of such situations include:

- when the failure of a protection scheme occurs
- during network contingencies or other emergencies
- when the network is configured abnormally
- when outages of plant are undertaken, for example, during scheduled or unscheduled maintenance

Unless stated otherwise, the requirements contained within this standard apply to general operations and do not apply to abnormal infrequent situations. System Operations Branch will maintain branch procedure NCB 0642 – Protection Withdrawal Authority (PWA), which prescribes the conditions under which a System Operator can keep high voltage plant in service with a lower-than-normal standard of protection.

4.3 Exceptions

This standard covers some aspects of detailed design which cannot be completely standardised, often requiring tailoring to each individual application. Exceptions to this Standard are allowed with the approval of the Delivery Manager Secondary Systems if compliance with Company Policy 9.2.2 – Network Protection, is achieved.

The Protection Engineer or Protection Specialist must document any proposed deviation from the requirements of this Standard, as well as the basis for the deviation, and obtain written approval from the Delivery Manager Secondary Systems before the design is issued.

4.4 Practicability

Where the term ‘practicable’ is used in this standard, it means cost effective and reasonably able to be done, giving regards to the circumstances. Unless otherwise stated, the determination of practicability will be made by the application Protection Engineer or Protection Specialist using appropriate engineering analysis and judgement and with reference to any requirements or guidance material in relevant Company Policies, Procedures, Workplace Instructions, guidelines, equipment manuals and other directions.

5 Principles and objectives

5.1 Purpose

The purpose of protection systems is to react to and isolate parts of the electrical network in the case of electrical faults and some other abnormal network conditions (for example, frequency excursion) to:

- prevent system instability
- prevent equipment damage to plant which is carrying the fault current

- minimise the extent of damage at the fault site and reduce the likelihood of collateral damage to other equipment through fire or explosion
- minimise the safety risk to humans and livestock
- minimise the extent of any power outage

5.2 Compliance

Protection schemes must comply with the requirements of the following documents:

- National Electricity Rules (Section 5)
- Service and Installation Rules – NSW Government Department of Trade & Investment
- AS 2067:2016 – Substations and high voltage installations exceeding 1 kV a.c
- ENA DOC 001-2008 – National Electricity Safety Code
- ENA DOC 018-2015 – Guideline for the fire protection of electricity substations
- Company Policy 9.2.2 – Network Protection

Protection schemes must be designed with due consideration being given to the following Company documents:

- Company Policy 9.1.2 – Reliability Principles
- Company Policy 9.2.5 – Network Asset Design
- Company Policy 9.2.10 – Network Asset Ratings
- Substation Design Instruction SDI 501 – Network Configuration
- Substation Design Instruction SDI 526 – Design of Substation Secondary Systems

5.3 Design objectives

Electrical protection schemes must be designed to achieve the following target objectives as far as is practicable. It is noted that there is usually a trade-off between the various objectives below which requires a balance between the trade-offs of competing requirements utilising good engineering judgement:

Table 1: Protection Objectives

Aspect	Objectives
Sensitivity	• Detect and clear electrical faults and detect other abnormal operating conditions that could lead to damage to the network or a potentially unsafe condition. It is recognised that some faults are not able to be detected by protection systems. • Protection schemes must be as sensitive as possible without being so sensitive that they could operate when they are not supposed to.
Speed	• Disconnect the faulted part of the network from the rest of the system in the minimum practicable time (taking into consideration the need to coordinate with other devices and other network phenomenon such as transients) to: – minimise damage to the faulted equipment and to the remainder of the network – prevent the loss of power system stability – reduce the probability and extent of injury to humans and livestock within the vicinity of the fault or exposed to remote voltages because of the fault, noting that it cannot protect against harm fully and that serious injury is likely to result from any contact where the person is in the fault path – minimise the probability or extent of damage to the company's property or to other property because of the fault – reduce the likelihood of starting a fire, noting that the level of current required for fire ignition is below the level at which protection can detect and operate minimise the extent of power system voltage disturbances

Stability	• Allow the primary plant being protected to operate within its rated voltage range and carry its rated normal, cyclic and emergency load currents, without the protection system operating. • Not operate for faults, or other transient or abnormal conditions for which the protection is not intended to operate for.
Selectivity	• Operate at the appropriate points of isolation to minimise the extent and duration of the interruption to supply because of a fault.
Dependability	• Be as reliable and redundant as is practicable.

5.4 Sensitivity

5.4.1 Mandatory criteria

Protection schemes must have sufficient sensitivity to detect and clear the following faults within their zone of operation under both normal and maximum reasonably foreseeable source impedance operating conditions in the normal operating configuration or any planned abnormal operating configuration:

- all bolted faults between two or more phase conductors; and
- where the power system is solidly earthed, or low-impedance earthed, all bolted faults between a phase conductor and an earthed conductor where that earthed conductor returns to the source of fault current by way of a deliberate low-resistance metallic connection.

For differential and overcurrent protections, a minimum sensitivity factor of 1.5 in comparison to the minimum fault level for all relevant fault types is taken to meet this requirement; however, a larger sensitivity factor is desirable and achievable in most cases. In the case that several sources of supply exist, this factor need not be achieved by all sources of supply simultaneously. A sensitivity factor lower than 1.5 may be acceptable in some cases where explicitly prescribed within this standard or as approved by the Delivery Manager Secondary Systems giving regard to the circumstances.

5.4.2 Desirable criteria

To detect as many other fault types as is practicable, the protection must be as sensitive as is practicable, but without causing an undue risk of causing a spurious trip or impacting on selectivity. An example of other fault types which this applies to include:

- earth faults where there is no deliberate metallic return path to source, for example pole substation earth grids
- high impedance faults (for example arcing faults) between two or more phase conductors, or between phase conductors and earth
- faults within or between different components of network plant such as transformer interturn winding faults and short-circuit faults within the elements of a capacitor bank

It is noted that protection cannot detect all faults, for example, some high impedance faults will be indistinguishable from load current.

5.4.3 Overloads

Protection systems will in general not be designed to prevent equipment overloads and will instead be designed to permit overloading as far as reasonable fault sensitivity permits. This is required to:

- allow for full utilisation of equipment to specified ratings (including cyclic and emergency ratings)
- prevent cascading protection operations
- minimise the likelihood of reliability impacts under these permissible temporary overloading scenarios

Protection or control systems will in some instances be used to prevent damage due to overloading of selected substation plant, such as large power transformers and capacitors, where this is practicable.

5.5 Speed

Protection systems must have sufficient speed to detect and clear electrical faults to meet system stability requirements (see section 5.6 below).

Protection systems must have sufficient speed to protect network elements which supply fault current to a faulted network element within the equipment's short time thermal rating limit for a bolted fault of any fault type. This must include allowance for the full automatic reclose cycle. It is accepted that some legacy network elements, such as HARDEX overhead earth wires and distribution feeders are not able to be protected to this standard.

5.6 Transient stability

There must be sufficient primary protection systems and backup protection systems (including circuit breaker failure protection systems) so that a fault of any fault type anywhere on the system is automatically disconnected in a time that would not cause the power system to become unstable. An exception to this rule is allowed in the case of circuit breaker failure or blind spot faults. Stability is primarily a design consideration at 132 kV, but it could also be applicable at lower voltages where fault levels are very high, or near to embedded generation.

For new or modified 132 kV lines as well as substation equipment, busbars and other connected plant, the following tabulated maximum fault clearing times apply unless longer times are proven (through a detailed study) not to cause network instability and the Australian Electricity Market Operator has been notified and has endorsed the proposal in writing. A modified feeder is taken to be a feeder where the primary plant has been materially altered and this results in an impedance change for the entire feeder to any downstream circuit breaker which exceeds 10% since the National Electricity Rules performance standards commencement date (16 November 2003).

Table 2:132 kV maximum clearing times for new or modified facilities (from NER Table S5.1a.2)

Relay end	Remote end	CB fail
120 ms	220 ms	430 ms

If the fault clearance times in Table 2 apply, the primary protection system must have sufficient redundancy so that short circuit faults of any fault type are cleared within the relevant fault clearing time with any single protection element (including any communications facility upon which the protection system depends) out of service.

5.7 Selectivity (coordination)

Protection will be set to be selective as far as is practicable in the normal network operating configuration. This is required to maximise network reliability and to achieve correct fault location diagnosis.

It is noted that protection cannot always maintain selectivity under all conditions and under all operating configurations. This is due to many factors, including the time grading characteristics of the protection systems being coordinated, sensitivity considerations, and the need for speed. In these circumstances, an appropriate judgment must be made by the Protection Engineer or Protection Specialist that best suits the application.

5.8 Dependability and redundancy

There must be sufficient primary protection systems, backup protection systems and breaker failure protection systems such that a bolted fault of any fault type is cleared in the times stated in section 5.6 above to maintain system stability.

Where system stability is not a consideration, there must be primary protection that protects electrical network assets within their short time current rating for all bolted faults as a minimum for existing sites. For new sites there must be sufficient redundancy to allow for failure of any one component unless the cost of doing so outweighs the risk. During protection system refurbishments, the system must be brought up to this standard where it is practicable to do so.

In the selection of scheme components, consideration must be given to the possibility of a common mode failure. Relays which complement each other in providing redundancy will normally be of a different make. Consideration must also be given to the use of different operating principles.

Full-range fuses are considered fail-safe and are therefore not required to be redundant if they are operated within their design limitations.

5.9 Other design requirements

5.9.1 Circuit breaker failure

Circuit breaker failure functionality must be employed on new protection scheme installations as far as is practicable to minimise the fault clearance time and the extent of outage in the case of a failure of the circuit breaker to operate within normal time limits. If the cost of doing so is excessive, remote backup protection is an acceptable alternative.

5.9.2 Calculation of fault levels

Fault level calculations will be required for the purposes of design in relation to equipment ratings, earthing safety levels and protection sensitivity and coordination.

Fault levels will be calculated using methodology as close as is practicable to the methodology prescribed in IEC 60909-0 - Short-circuit currents in three-phase a.c. systems, Part 0: Calculation of currents.

The following conditions apply to minimum and maximum fault calculations:

Table 3: Minimum fault level calculation method

Parameter	Requirements
Configuration	• Generation plant close to the fault will be the minimum required for a viable network. • Network elements close to the fault (such as feeders and transformers) will be switched out to provide the highest possible source impedance whilst still providing a viable network operating condition. For a distribution network this will mean using only one zone substation transformer to source the fault. • Synchronous machine impedance.
Voltage Factor (c)	**0.9**

Table 4: Maximum fault level calculation method

Parameter	Requirements
Configuration	• Maximum operating levels of generation plant and with all electrical networks in service. • Normally open points which are only closed to maintain supply during rearrangement of the system, and for less than 1% of the time may be assumed to be open. • Motor contribution must be included if there is a significant proportion of motor load on the network. • Machine impedances as required (sub-transient will yield higher fault levels close to generation and this will be relevant to high-speed protection operation).

Voltage Factor (c)	**1.1**

5.9.3 Current transformers (CT)

Current transformers used for protection schemes must have suitable ratings and performance to prevent damage to the CT or protection systems during normal system operation and fault conditions, and for the protection to operate as desired.

Current transformers used to supply protection systems must not be used for any other purpose such as transducers and metering circuits. Exceptions to this rule may be approved by the Delivery Manager Secondary Systems in exceptional circumstances. Approval will not normally be given unless the importance of such a circuit is high, and if all other reasonable avenues have been exhausted.

5.9.4 Voltage transformers (VT)

Voltage transformers used for protection schemes must be of the 5-limb core configuration in the case of a single VT unit, and must have a suitable performance class so that connected protection schemes operate as required. In the case where two redundant protection schemes utilise the same VT, the design must be such that a failure of the VT signal to both protection schemes simultaneously does not prevent a fault clearance within the prescribed limitations of this Standard.

5.9.5 DC supplies and trip circuits

The protection relay supply must come from a DC battery bank system which complies with the following standards:

- Equipment Technical Specification ETS 0085 – Battery systems
- Substation Design Instruction SDI 513 – Substation batteries and battery chargers
- Substation Design Instruction SDI 526 - Design of Substation Secondary Systems

Redundant protection schemes must not be supplied from the same battery bank where multiple banks are available.

5.9.6 Trip circuits

Circuit breaker trip circuits must comply with SDI 526 - Design of Substation Secondary Systems and must be continuously supervised where it is practicable to do so.

5.9.7 Secondary plant thermal and mechanical protection

All secondary systems must be designed to operate within their continuous and short-time thermal ratings. This includes but is not limited to protective relays, current transformers and wiring.

5.9.8 Flagging, indication and fault recording

As far as practicable, protective relays will be capable of recording events and provide SCADA indication so that the relay and function within that relay which caused the protection operation can be determined both locally and remotely.

5.9.9 Scheme monitoring

As far as practicable, protection schemes which protect systems operating at 11 kV and above, other than those installed within distribution substations, will incorporate monitoring of the critical elements such as the protection relay, the trip circuit, and the communications system. A failure of any of these systems will result in both a local and remote indication of the failure.

5.9.10 Scheme naming conventions

Where two fully or partially redundant protection schemes are installed to protect the same item of plant, those schemes will be referred to as the #1 and #2 protection schemes. It is preferred that the #1 and #2 protection schemes trip the circuit breaker through the #1 and #2 trip coil respectively.

Where two schemes have a substantial difference in functions and/or operating performance, it is preferred but not mandatory that the fastest or more comprehensive protection scheme be referenced as the #1 protection scheme.

6 Transmission feeder protection

6.1 Scope

This section applies to Endeavour Energy owned transmission mains operating at 33 kV, 66 kV and 132 kV.

6.2 Scheme requirements

Feeder protection systems may utilise any combination of the following protection types, provided they are suitable for the application:

- differential
- distance
- directional overcurrent (and earth fault)
- non-directional overcurrent (and earth fault)
- intertripping

New installations will generally be designed with two protection schemes on any feeder for which there is a source of fault current from behind the relay. It may however be acceptable in some instances at 66 kV and below, (and it is the case in many existing installations) that a single protection scheme be used if the cost of a second scheme is disproportionate to the benefit and provided that remote backup protection is available.

The types of protection used will be selected for each item of plant on a case-by-case basis giving due consideration to the variable system factors in each case. Some factors which can influence the selection and configuration of protection systems include (but are not limited to) the following:

- the configuration of the feeder (for example, teed feeder, or transformer ended feeder)
- the feeder length and impedance
- the source impedance ratio
- the continuous rating and short time thermal constraints of the feeder and other plant
- the load levels both normal and contingency
- the critical clearance time for system stability
- the National Electricity Rules clearance time requirements
- the fault levels and stability, sensitivity, and coordination requirements
- the possible system configurations both normal and contingency
- the availability and type of communications
- the availability and performance of instrument transformers (CT's and VT's)
- the consideration of high resistance faults, particularly if there is no low impedance earth return path (for example, no overhead earth wire (OHEW) on the feeder)
- the location of current transformers and the presence of blind spots
- the backup and CB failure requirements
- the need for additional or abnormal relay functions such as check synchronisation
- special requirements to interface with high voltage customers or other utilities
- the quality, reliability and redundancy of the scheme

6.2.1 Typical scheme combinations

The most common protection scheme combinations are shown in the table below:

Table 5: Typical transmission feeder scheme combinations

Voltage	#1 protection	#2 protection	Notes
132 kV	Differential	Differential	If duplicate communications are available.

	Distance	Distance	If communications are unavailable and stability is not impacted.
33 kV or 66 kV	Differential	Distance	If communications are available.
	Distance	Overcurrent	If communications are unavailable.

6.2.2 Numerical differential protection

Microprocessor based multi-function protection relays are the preferred relay type for feeder differential protection schemes. These will normally but not exclusively communicate through a dedicated fibre-optic path or through a multiplexer system connected through optical fibres. Alternative means of digital communication must be approved by the Delivery Manager Secondary Systems and will only be approved if the communications system is assessed to have reasonable levels of reliability and availability performance as applicable to the individual scheme application. A failure of the communications system (as indicated by the protection relay) must enable a local and remote SCADA alarm.

Numerical differential relays can incorporate distance and overcurrent protection which can be enabled either full time, or only in the event of a failure of communications and/or VTs to provide an additional degree of redundancy, depending on the scenario. If Critical Clearance Times are less than the distance Zone 2 timer, Zone 2 Acceleration may be implemented to maintain adherence to the NER.

6.2.3 Copper pilot based analogue differential protection

Copper pilot based differential schemes are not preferred and must only be installed where there is no available dedicated fibre-optic link, or a multiplexed link utilising C37.94. In this case, a Translay protection scheme can be used, provided that the pilot is technically suitable. Copper pilot based differential schemes must incorporate a pilot supervision scheme which must enable a SCADA alarm in the case that the supervision relay indicates a communications failure.

6.2.4 Distance protection

If no communications are available, it is preferable that at least one distance scheme be used on each feeder to achieve high speed fault clearance for a substantial proportion of the feeder. Distance protection however may not be suitable in all cases, for example, if the transmission line is a very short distance (and very low impedance), the measurement accuracy limitations may not allow for accurate distance measurement. A suitable VT is also required.

6.2.5 Feeder CB automatic reclose

Automatic reclose of the circuit breaker is undertaken by the SCADA system, not the protection system. Reclose is generally initiated by elements that do not overreach the feeder, e.g. Differential and Distance Zone 1.

6.3 Setting and application considerations

6.3.1 Maximum clearing time absolute limits

The following maximum clearing times are applicable to all transmission feeders in addition to any other requirements such as the National Electricity Rules, equipment short time thermal ratings and stability requirements for 132 kV feeders. If these times cannot reasonably be met, network and secondary system augmentation options to reduce the clearing time must be explored and implemented if reasonably practicable. Exceptions are allowed with approval from the Delivery Manager Secondary Systems.

Table 6: Transmission feeder clearing time limits (bolted fault)

Situation	OC & EF **Primary**	OC & EF **Backup & CB Fail**

Normal operation (maximum foreseeable source impedance)	2 s	3 s
Abnormal configuration or disabled protection scheme (actual source impedance)	3 s	Not required

6.3.2 Equipment short-time thermal ratings

The short time thermal rating of conductors including overhead earth wires must not be exceeded, regarding both primary and backup protection in the normal system configuration. In temporary abnormal system configurations or during protection outages, redundancy is not mandatory.

It is acknowledged that some legacy network elements (for example, HARDEX and steel overhead earth wires) are not able to be protected to this standard. Where permanent protection system changes which decrease the speed of protection are proposed, the non-compliance must be approved by the Delivery Manager Secondary Systems. Abnormal or concerning non-compliances, for example where the level of exceedance is extreme, must be brought to the attention of the Delivery Manager Secondary Systems.

6.3.3 Differential protection

Differential protection schemes will normally be set in accordance with the relay manual provided by the manufacturer giving due regard to the range of expected fault levels, instrument transformer performance, and through fault considerations.

6.3.4 Typical distance settings

The following table details the typical distance setting parameters that will be used on transmission feeders. These settings are not mandatory, and the settings must be tailored to the application as appropriate.

Table 7: Distance protection setting methodology

Zone	Impedance Setting	Time	Notes
1	80%	0 ms	• 80% to closest CB in the case of a three or four-ended feeder. • Mutual coupling may result in substantial overreach errors, so a lower impedance setting may be required. • Supervision or starters may be applied to improve scheme security. • This zone may be disabled when there is significant risk of overreach due to high SIR.
2	120%	As required	• 120% of furthest CB in the case of a three or four-ended feeder. • Mutual coupling and remote infeed effects may result in substantial under reach errors, so a higher impedance setting may be required. • Time delay setting as required for coordination with downstream protection. • Overreach errors must be allowed for in the selection of the time delay setting. • 400ms is the normal time delay setting when grading only with instantaneous protection schemes. • Provision to accelerate this zone for comms failure shall be applied to new 132kV instalments.
3	As required	As required	• Impedance setting as required to: • Provide sufficient backup protection • Allow for high impedance faults • Underreach and overreach errors will be allowed for in the selection of the impedance setting and time delay. • Does not encroach upon load current. • Note: Zone 3 settings are not mandatory.

6.3.5 Communications aided distance protection

Distance protection can also be used to provide instantaneous protection clearance for the entire feeder by utilising end to end communications. The permissive overreach transfer trip scheme (POTT scheme) is the preferred communications aided distance scheme.

Where instantaneous protection operation is required to meet stability requirements, the POTT scheme will incorporate additional functionality which results in an instantaneous protection operation under all system conditions, particularly in the case of weak infeed from the remote end, and in the case that the remote end CB is open.

6.3.6 Mutual feeder inductive coupling

When two or more feeders are near each other, either over the whole or a part of their length, there is mutual inductive coupling between the circuits. The impact of mutual coupling on the positive and negative sequence impedance is usually small enough to neglect. The impact of mutual coupling on the zero-sequence impedance can be significant enough to result in incorrect protection operation if it is not considered in the settings.

The zone impedance reach settings and time delays will be adjusted to confirm that feasible overreach and underreach conditions do not compromise protection requirements. Mutual coupling effects only apply to earth faults. It is desirable to apply reach adjustments only to earth fault reaches in allowing for mutual coupling effects.

Table 8: Distance protection mutual coupling effects

Condition **(parallel feeder)**	**Effective impedance**	**Result**
Fault current in same direction	Increased	Underreach
Fault current in opposite direction	Reduced	Overreach
Out of service and earthed	Reduced	Overreach

6.3.7 Remote infeed

If there is a source of fault current between the relay and the fault point, the relay will measure apparent impedance that is larger than the actual impedance and will therefore under reach. The zone impedance reach settings and time delays will be adjusted so that feasible under reach conditions due to remote infeed do not compromise proper operation.

Table 9: Distance protection remote infeed effects

Condition	**Effective impedance**	**Result**
Remote infeed	Increased	Underreach

If the remote infeed is from a tee on the protected feeder, the impedance reach will need to be increased on zone 2 and zone 3 to compensate. If the remote infeed is into or beyond a remote end busbar, normally only zone 3 will need to be adjusted, and then only if the adjustment is required to provide sufficient redundancy for downstream equipment.

A downstream transformer with an earth reference (for example, an earthed star winding) on the feeder side can supply zero sequence current into the fault and will be considered as an equivalent infeed, though in most cases the contribution will be small.

6.3.8 Power swing blocking

Disturbances in the power system which are electrically close to generation can result in power swings which can cause the load impedance to enter the relay operate characteristic. Operation of relays during a power swing can exacerbate the situation and can potentially lead to cascading protection operations and the shutdown of major portions of the power system. In these instances, power swing blocking functionality will be applied within the relay to differentiate between fault and power swing conditions, and to prevent relay operation for power swings.

6.3.9 VT Failure

Where duplicate distance protection is employed, fault clearance must be adequate despite a VT failure. This can be achieved by adding relay logic that enables a definite time overcurrent and earth fault element with a 40 ms time delay. Alternatively, the distance relay can be set up to trip immediately when it loses VT supply, this is not the preferred method as it may result in unnecessary loss of load.

When distance protection is applied to 33 kV and 66 kV feeders with non-voltage dependent backup protection the distance elements can usually be blocked for VT failure to maintain optimum reliability. The failure must still result in a SCADA alarm. When the backup protection is also voltage dependent, special consideration needs to be taken to maintain fault detection and clearance capability during VT failure conditions.

6.3.10 Communications links

The preferred end to end communications for protection is through dedicated single mode optical fibres. Communications via a multiplexer is acceptable if there is an insufficient quantity of available dedicated optical fibres, or to interface to another utility such as TransGrid. Legacy schemes utilise underground or overhead copper pilots and these may also be utilised if necessary. Other means of communication between relays must be approved by the Delivery Manager Secondary Systems.

Where end to end communications is required for acceptable protection operating times, the communications schemes for each complimentary protection scheme must be redundant, must not utilise pilots or fibres in the same cable or overhead earth wire, and as far as practicable have geographical path diversity to minimise the likelihood of a simultaneous failure. This is normally a requirement for the protection of transmission lines operating at 132 kV. At lower voltage levels, redundant communications systems are not normally required, however if redundant communication paths are available, it is preferred that a backup path be made available for the case that the normal path fails.

Protection schemes that rely on communications channels for protection operation will initiate a SCADA alarm for communications channel failure.

6.3.11 Voltage transformers

Directional and distance protection schemes rely on VT's as well as CT's. It is preferable that line VT's are used, however if no line VT is available, a bus VT on the bus section that the relevant feeder is connected to is acceptable.

All new relay applications which rely on VT measurement must incorporate VT supervision and must initiate a SCADA alarm in the case of VT failure.

6.3.12 Circuit breaker failure

New protection schemes will generally incorporate CB failure functionality to minimise the clearance time and reliability impact of a circuit breaker failure event. Cascading circuit breaker failure should be accounted for where practicable.

In the case of two-ended feeders, an intertrip may be used to trip the remote end CB for a local end adjacent busbar protection trip. For three-ended feeders, an intertrip to the remote end CB would normally only be sent in the case of a local feeder CB fail event.

6.3.13 Sync check

Where deemed appropriate, check or blocking facilities must be applied to the automatic reclose equipment in those circumstances where there is any possibility of the two ends of the line being energised from sources that are not in synchronism. This is normally achieved with a sync check function in a modern microprocessor relay, which sends appropriate signals to the SCADA system, and has a relay contact in series with circuit breaker close signal to prevent a close attempt when the system is not in synchronism.

6.3.14 Switch on to fault (SOTF)

Where practicable, protection systems will incorporate switch on to fault functionality to achieve instantaneous protection operation in the case of inadvertent closing onto pre-existing earth faults or maintenance earths.

7 Transformer protection

7.1 Scope

This section applies to Endeavour Energy owned power transformers with a high voltage side which operates at 33 kV, 66 kV and 132 kV.

7.2 Scheme requirements

7.2.1 Transformers 5 MVA or lower

The protection scheme associated with transformers that have a base rating of 5 MVA or lower will be considered on a case-by-case basis and must be approved by the Delivery Manager Secondary Systems.

7.2.2 Transformers greater than 5 MVA

Transformers that have a base rating greater than 5 MVA will be protected by two dedicated and independent protection schemes as well as protection for the case of circuit breaker failure.

For transformers with any terminal connected at or above 66 kV, both schemes will include differential protection across the primary and secondary windings. In all other cases, at least one scheme will include differential protection across the primary and secondary windings, and the other scheme will include IDMT overcurrent protection on the high voltage and low voltage side of the transformer if duplicate differential is not employed.

Restricted earth fault (REF) and neutral earth fault (NEF) protections are optional and can be applied when necessary (for example, to provide backup protection for other equipment) or when this protection can be applied at negligible cost, for example, if a restricted earth fault protection element is available in the differential relay. Note: REF protection is highly desirable in the case of a star winding which is impedance earthed. REF will normally be applied in the case of new substation builds.

Where available, main tank and tap changer Buchholz, pressure relief, overpressure, and gas collection protections will be applied to one of the schemes, and where applicable, will be applied to the scheme which does not include differential protection.

7.2.3 Transformer ended feeders

The protection requirements for transformer ended feeders are identical to that of transformers except that isolation may be achieved using remote end circuit breakers if signalling is available to inter-trip to those circuit breakers.

It is also acceptable for differential protection to protect the entire feeder and transformer as one unit. If this method is used, there must be a method to allow for differentiation between a feeder fault and a transformer fault if the feeder consists of any overhead network, or if the underground feeder length is substantial.

7.2.4 Back-fed delta windings

Where the primary winding of a transformer is a delta winding, and in the normal network configuration, a single fault scenario, without a protection failure, can lead to an overhead feeder remaining or becoming energised from the delta winding, a protection system such as neutral voltage displacement is required to de-energise the transformer in case the feeder sustains an earth fault.

7.2.5 CT configuration

Wherever practicable, CTs will be connected in a star configuration, and vector group and turns ratio compensation will be completed through computation within the relay.

7.2.6 Latching of the trip function

Any transformer protection operation that indicates that the fault location is likely to be within the transformer or tap changer tank will prevent closing of the CBs until someone attends site and resets the protection.

Where applicable, a positive indication of an internal transformer fault will be signalled to the SCADA system so that any automatic restoration actions, for example, automatic switching to a standby transformer can take place.

7.3 Setting and application considerations

7.3.1 Maximum clearing time limits

The following maximum clearing times are applicable to all transmission transformer protected zones for a high voltage bolted fault external to the transformer. This is in addition to any other requirements such as the National Electricity Rules, equipment short time thermal ratings and stability requirements as given in section 5.6.

If these times cannot reasonably be met, network and secondary system augmentation options to reduce the clearing time must be explored and implemented if reasonably practicable. Exceptions are allowed with approval from the Delivery Manager Secondary Systems.

Table 10: Transformer clearing time limits (bolted fault)

Situation	OC & EF **Primary**	OC & EF **Backup & CB Fail**
Normal operation (maximum foreseeable source impedance)	2 s	3 s
Abnormal configuration or disabled protection scheme (actual source impedance)	3 s	Not required

7.3.2 Differential (including REF)

Differential protection settings will be selected with reference to the manufacturer's recommendations which are usually provided in the relay manual, considering the range of expected fault levels and instrument transformer performance.

Harmonic restraint or blocking must be applied to the restrained differential element to minimise the risk of a trip due to magnetising inrush current and CT saturation. An unrestrained element will also be applied so that operation for high level faults is not delayed by the restraint or blocking functions and will be set above the maximum calculated inrush current magnitude.

7.3.3 Overcurrent and earth fault (including NEF)

Overcurrent pickup settings must allow for at least a continuous 130% overload of the transformer on any feasible tap setting, unless this is a highly unlikely operating condition (for example, if the forecast maximum substation load currents are substantially lower than the transformer capacity), or if the required level of sensitivity cannot be achieved.

IDMT overcurrent and earth fault settings where applied must coordinate fully with all distribution feeder protection relays for all single feeder fault conditions. If overcurrent protection is applied on the HV side of the transformer, this need not fully coordinate with an overcurrent and earth fault protection installed on the LV side of that transformer, however a small coordination margin will be applied so that it is unlikely for the HV overcurrent to ever operate alone for a fault beyond the LV overcurrent or earth fault protection.

It is desirable that the transformer overcurrent relays have a fast or instantaneous reset to enhance grading for multiple feeder faults in quick succession, which are likely to occur during heavy lightning activity.

7.3.4 Temperature settings

The winding temperature monitoring device (traditional calculated WTI, or internal fibre optic temperature sensor device) is the preferred device to drive the cooler controls, alarms, and trips provided that the information is available to calibrate the device.

If there is no winding temperature monitoring device available (or suitably calibrated), the OTI device can be used to drive the cooler controls and trip. If a WTI device is fitted, but the device cannot be calibrated, the input CT can be shorted and earthed, so that it effectively functions as an OTI. In this case the device must be marked “OTI (WTI CT shorted)”.

Both the winding temperature monitoring device and the oil temperature monitoring device (where both are installed and calibrated) must initiate a SCADA Alarm at the appropriate alarm level.

The temperature settings must be set as per the manufacturer’s recommendations.

Table 11: Normal busbar protection requirements

Busbar application	Requirement (per bus section)
132 kV or 66 kV	2 x differential schemes
33 kV (transmission substations)	2 x differential schemes
33 kV (zone substations) & 11/22 kV	1 x differential scheme (if backup protection for the busbar is available, otherwise 2 x schemes are required)

7.3.5 Current differential scheme

Low impedance busbar protection is the preferred differential protection.

7.3.6 Latching of the trip function

Any busbar protection operation will result in a latched trip which cannot be unlatched remotely. Additionally, signals will be sent to the SCADA system to inhibit attempts to close the bus circuit breakers. These functions will normally (but not exclusively) be achieved by way of a multitrip relay or by latching out the closing circuit.

Where applicable, the busbar fault will be signalled to the SCADA system so that any automatic restoration actions can take place.

7.3.7 Inter-trip scheme

An inter-trip scheme may be used to send an inter-trip to the remote end (source substation) when a busbar fault occurs. This will achieve fast isolation of the incoming feeder connected to the faulted bus section from the remote end regardless of a circuit breaker failure event. To avoid the potential for unnecessary loss of load, this would not normally be employed on three-ended feeders.

7.3.8 Circuit breaker failure and backup protection

A circuit breaker failure scheme or suitable backup protection systems must be employed so that all busbar faults, including blind spot faults are cleared despite a circuit breaker failure to open, or any other single protection scheme element failure.

In the case of three-ended feeders, an inter-trip to the remote end CB would normally be sent in the case of a local feeder CB fail event.

7.4 Setting and application considerations

7.4.1 Maximum clearing time limits

The following maximum clearing times are applicable to all transmission busbars in addition to any other requirements such as the National Electricity Rules, equipment short time thermal ratings and stability requirements.

If these times cannot reasonably be met, network and secondary system augmentation options to reduce the clearing time must be explored and implemented if reasonably practicable. Exceptions are allowed with approval from the Delivery Manager Secondary Systems.

Table 12: Busbar protection clearing time limits

Situation	OC & EF **Primary**	OC & EF **Backup & CB Fail**
Normal operation (maximum foreseeable source impedance)	2 s	3 s
Abnormal configuration or disabled protection scheme (actual source impedance)	3 s	Not required

7.4.2 Setting selection

Differential protection settings will be applied with reference to the manufacturer's recommendations which are usually provided in the relay manual. Due regard must be given to the range of expected fault levels and instrument transformer performance.

8 Capacitor Bank Protection

8.1 Scope

This section applies to shunt power factor correction capacitors with internally fused cans which are installed within zone and transmission substations operating at 11 kV, 22 kV, 33 kV, 66 kV and 132 kV.

The protection of other types of capacitor bank will be determined on a case-by-case basis.

8.2 Scheme requirements

New Endeavour Energy capacitor bank units are normally internally fused. The normal failure mode of individually fused elements is open circuit. An open circuit element will cause an overvoltage on the remaining elements that are in parallel with the failed element.

8.2.1 Capacitor bank configurations

The grounded star configuration provides a low impedance path to ground for lightning surge currents, zero-sequence currents, and some surge voltages. It may, however, provide large discharge currents into an external earth fault.

The un-grounded star configuration is more common within Endeavour Energy substations and will not discharge into an external earth fault, but still can discharge into an external phase to phase fault.

8.2.2 Typical protection philosophy

Overcurrent elements provide protection for terminal faults. For lower-level internal terminal faults and individual capacitor element faults that will not produce substantial fault current, unbalance protection is used.

Due to their decreasing impedance with an increase in frequency, capacitors are very sensitive to harmonic voltages. Overvoltage protection provides for excessive capacitor bank currents (because of system voltages), as well as protecting the system against over-voltages that under some conditions are caused by the capacitor bank.

Loss of supply trip and discharge timers will be used so that the capacitor bank is not re-energised with a remaining charge.

The following table summarises the abnormal conditions that can occur with capacitor banks and the protection that can be used to protect against such conditions.

Table 13: Capacitor bank protection guidelines (IEEE C37.99)

Condition	Type of protection	Remarks
Faulted capacitor element	External or internal fuse for fused banks; weld, which occurs at the failure, for banks without fuses.	Fuses should be fast to coordinate with fast unbalance relay settings but should not operate during switching or external faults.
Fault from capacitor elements to case, bushing failure, faulty connection in capacitor unit	Fuse for externally fused capacitor; unbalanced protection for internally fused banks or banks without fuses.	For externally fused capacitor banks, fuses should be fast to coordinate with fast unbalance relay settings but should not operate during switching or external faults. For internally fused banks or banks without fuses, the unbalance protection should be fast to avoid case rupture but should not operate during switching or external faults.
Fault in capacitor bank other than in unit (arcing fault in the bank)	Unbalance protection. Relay should have a band-pass filter for the fundamental current or voltage for security.	Unbalance protection should be fast to minimise damage to other units during a major fault.
Continuous overvoltage on capacitor elements or units due to faulted elements or fuse operations within the bank	Unbalance protection. Relay should have a band-pass filter for the fundamental current or voltage for security.	Bank should be tripped for voltages >110% of rated voltage or as recommended by manufacturer on healthy capacitor units. An alarm may be added for 5% unbalance or one unit out. In some critical applications, an alarm with delayed tripping above 110% of rated voltage is used.
Rack-to-rack flashover in two series group phase-over-phase single star banks	Phase overcurrent or negative sequence relay; unbalance current for star-star capacitor banks.	Fast operation is required to minimise damage.
Power system frequency overvoltage	Phase voltage relays.	For a distorted voltage waveform, the capacitor dielectric is sensitive to the peak voltage.
Harmonic current overloading	Relay sensitive to harmonic current.	Where excessive harmonic currents are anticipated, harmonic relaying may be required.
Bus fault in capacitor installation or major capacitor bank failure	Circuit breaker or circuit switcher with conventional relays; or, power fuses.	Relays or power fuses should be as fast as possible without nuisance operations due to outrush currents into nearby faults.

System outage	Under voltage relays	Capacitor banks (which may be) energised through a transformer without load on the transformer may need to be switched off before re-energising the system.
Breaker failure	Conventional breaker failure relays.	Local or remote breakers should have capacitor switching capability if they trip the bank without parallel load due to breaker failure considerations.

8.2.3 Capacitor bank scheme requirements

Table 14: 132 kV capacitor bank scheme requirements

Protection type	Minimum	Remarks
Overcurrent	2	Must include high set elements for bolted terminal faults and clear in less than 120 ms.
Earth fault	2*	*Unearthed banks only.
Unbalance	2	
Overvoltage	1	
Circuit breaker failure	2	
Loss of supply trip	1	
Discharge timer	1	

Table 15: 33/66 kV capacitor bank scheme requirements

Protection type	Minimum	Remarks
Overcurrent	2	A high set element for terminal faults is preferred and may be required if close to generation.
Earth fault	2*	*Unearthed banks only.
Unbalance	2	One is acceptable for existing bank retrofits.
Overvoltage	1	

Circuit breaker failure	1	Provided that local backup protection is available for high level faults.
Loss of supply trip	1	
Discharge timer	1	

Table 16: 11/22 kV capacitor bank scheme requirements

Protection type	Minimum	Remarks
Overcurrent	2	A high set element for terminal faults is preferred.
Earth fault	2*	*Unearthed banks only.
Unbalance	1	
Overvoltage	1	
Circuit breaker failure	1	
Loss of supply trip	1	
Discharge timer	1	

8.3 Setting and application considerations

8.3.1 Capacitor bank ratings

The specified rating of a capacitor bank is based on the highest system voltage, which is usually 110% of the nominal voltage.

For example, a 33 kV, 10 MVAr (175 A) nominal capacitor bank will usually be specified (nameplate rated) at 36.3 kV, 12.1 MVAr, and a rated current of 192 A.

The maximum continuous rating of the capacitor bank is even higher than its specified (nameplate) rating. The following table details the typical ratings of a capacitor bank.

Table 17: Capacitor bank example settings (33 kV, 10 MVAr)

Protection type	Minimum	Remarks	Protection type

Overcurrent	2	A high set element for terminal faults is preferred.	Overcurrent
Earth fault	2*	*Unearthed banks only.	Earth fault
Unbalance	1		Unbalance
Overvoltage	1		Overvoltage
Circuit breaker failure	1		Circuit breaker failure
Loss of supply trip	1		Loss of supply trip
Discharge timer	1		Discharge timer

8.3.2 IDMT phase overcurrent protection

The overcurrent pickup will normally be at least 150% of the nominal capacitor bank current to allow for the full use of the capacitor bank. The curve type and time multiplier will be chosen based on calculated inrush currents and relay characteristics.

8.3.3 High set phase overcurrent protection

An instantaneous setting will normally be used to protect against solid terminal faults and is required at 132 kV unless other instantaneous protections are used (for example, high-impedance differential).

An allowance will be made for transient inrush current at switch-on, which can reach peak values of around 20 times the nominal current.

For modern numerical relays with a fundamental frequency band-pass filter, the high set element can be set to around five times the nominal capacitor bank current but must be time delayed by two cycles (40 ms) to allow for accurate Fourier Transformation calculations within the relay.

For relays that do not have fundamental filtering, the inrush current will have to be calculated for each application, and appropriate settings chosen based on these calculations.

8.3.4 Earth fault protection - earthed capacitor banks

For earthed capacitor banks, earth fault protection is not usually used. If used, it will not normally have an instantaneous element due to the potentially large outrush currents and unbalanced load currents that can occur during external faults.

Suitable earth fault settings will often be no more sensitive than the phase overcurrent settings. Adequate earth fault protection for solid capacitor bank faults is usually afforded by the overcurrent elements.

8.3.5 Earth fault protection - unearthed capacitor banks

For unearthed capacitor banks, the earth fault pickup can usually be set at 2% of the capacitor bank maximum fault current, but not less than 20% of the rated current of the capacitor bank. A typical suitable characteristic would be the IEC Standard inverse with a time multiplier of 0.1.

8.3.6 Shared feeder and capacitor bank

Zone substation capacitor banks in some cases share a circuit breaker with a distribution feeder. In many older substations, the feeder circuit breaker is not suitable to break the capacitor bank current. Where this is the case, a feeder protection operation must trip the capacitor bank circuit breaker before the feeder circuit breaker by a margin of at least 0.1 seconds to prevent the non-rated feeder circuit breaker from breaking the capacitor bank current.

8.3.7 Unbalance protection

Unbalance protection provides for arcing faults in the capacitor bank which may not be large enough to operate the overcurrent elements and provides overvoltage protection on remaining capacitor elements due to faulted elements or fuse operations within the bank, which will not result in any fault current.

Unbalance protection can be applied in many ways depending upon the capacitor bank arrangement and type.

One common method is neutral unbalance protection, where a current transformer is used in the neutral connection between two identical star-connected banks. A normal overcurrent relay (often definite time) is usually appropriate.

Another method that can be used is voltage differential (or voltage tap) protection. This protection scheme uses voltage inputs from a voltage transformer connected to the bus, and another connected to the bank at some mid-point (not necessarily exactly in the middle). Many modern numerical capacitor bank relays have suitable algorithms to calculate the voltage differential.

An unbalance resulting in no more than 110% voltage on remaining capacitor elements is generally acceptable for continued normal operation. An alarm will be triggered once the maximum number of individual elements has failed, but before the 110% voltage limit is exceeded. Once an unbalance that results in greater than 110% voltage across any remaining elements is reached, a trip of the capacitor bank must occur.

A trip for a severe bank unbalance must be as fast as possible and be coordinated with the maximum fuse clearing time; generally, it should occur between 0.3 to 0.5 seconds.

For new capacitor bank protection, the manufacturer should be able to provide recommended settings. Alternatively, if all capacitor bank parameters are known, IEEE Standard C37.99:2012 - Guide for Protecting Shunt Capacitor Banks, should be consulted to select appropriate unbalance protection settings.

8.3.8 Overvoltage (and overload) protection

Capacitor banks are very sensitive to system over-voltages because of the high field strength in the dielectric and resultant low safety margin. The maximum permitted continuous RMS voltage of a capacitor bank (including harmonics) can be identified on the nameplate or in the manufacturer's data and is usually at least 110% of the rated voltage. The maximum continuous crest voltage is at least 1.2 x $\sqrt{2}$ of the rated RMS voltage.

Relays must be set to operate based on total RMS voltage including harmonics, and not on the filtered fundamental frequency voltage.

Superseded IEEE Standard 18:1992 – Standard for Shunt Power Capacitors, specifies the permitted overvoltage and length of time with a piece-wise linear characteristic. Most dedicated numerical capacitor bank relays include this characteristic, and it is recommended that these settings be used when available. This can be used in the absence of overvoltage recommendations from the capacitor bank manufacturer.

8.3.9 Pressure relief

If pressure relief protection is installed, it must be used to trip the bank unless it is not practicable to do so.

8.3.10 Loss of bus voltage

To avoid re-energisation of the capacitor bank with a remaining charge, the bank circuit breaker must be opened whenever the supply is lost to the bank.

8.3.11 Discharge timer

To avoid energisation of a capacitor bank with a remaining charge, a block must be applied so that the capacitor bank circuit breaker cannot be closed if it has not been de-energised for long enough to allow the capacitor bank to fully discharge. The capacitor bank will have to discharge every time the circuit breaker is opened, or the connected busbar loses supply voltage.

An undercurrent element connected to a timer is one suitable method of achieving this. The discharge time can be specified by the manufacturer and is usually no longer than 10 minutes.

9 Distribution Feeder Protection

9.1 Scope

This section applies to Endeavour Energy owned 2 and 3 wire distribution mains operating at 11 kV and 22 kV and covers the network between the zone substation circuit breaker and the distribution substation fuses or circuit breakers. The same principles apply to 12.7 kV single wire earth return (SWER) lines except that earth fault (EF) and sensitive earth fault (SEF) protection is not able to be provided because load currents flow to earth, making earth faults indistinguishable from load current.

9.2 Scheme requirements

9.2.1 Zone substation circuit breaker

Distribution mains will normally be protected by Inverse Definite Minimum Time (IDMT) overcurrent (OC) and earth fault (residual overcurrent) protection functions at the zone substation circuit breaker. A definite minimum time (DT) and an instantaneous overcurrent and earth fault protection function, as well as a SCADA remotely enabled instantaneous overcurrent and earth fault function must also be applied to new installations and refurbishments where it is practicable to do so.

A SCADA enabled SEF function will normally be made available on all distribution feeders and must be available if the protection system provides coverage for any overhead powerline sections, including in any reasonably foreseeable abnormal network configuration. It is noted that system operators will need to disable the SEF function to prevent unwanted protection operations during some network conditions, such as when feeder sections are being switched one phase at a time, or when multiple feeders are being operated in parallel, which can lead to significant false earth fault current being measured by the protection system.

Zone substation circuit breakers must have two protection relays installed, which as a minimum provide duplication of the overcurrent, earth fault IDMT and SEF (where practicable) functions, and which achieve the specified minimum sensitivity and speed requirements, including protection of all primary plant within its short time thermal rating. Each relay must utilise a different set of CTs, a different DC supply, and a different trip coil if practicable. It is accepted that some legacy schemes do not achieve this requirement. Legacy schemes must be brought up to this standard during switchgear or protection refurbishment projects where it is practicable to do so.

Circuit breaker failure (CBF) protection will normally be employed on at least one overcurrent and earth fault relay at the zone substation and must be initiated by the overcurrent and earth fault functions. It is preferred that CBF protection is available for the SEF function as well. It is accepted that some legacy schemes do not include CBF protection. Legacy schemes must be brought up to this standard during switchgear or protection refurbishment projects where it is practicable to do so.

9.2.2 Core balance CT

A core balance CT may be applied to the distribution feeder cable at the zone substation on distribution feeders which have a substantial length of overhead powerlines running through high bushfire risk areas. Core balance CT's will normally only be applied if practicable and in conjunction with a major protection system or switchboard refurbishment project. Remote control to enable a more sensitive SEF setting will normally be made available on these feeders.

9.2.3 Line reclosers

Line reclosers will normally include overcurrent, earth fault and SEF functions. The overcurrent functions will normally include IDMT overcurrent and earth fault protection, as well as DT overcurrent and earth fault protection where it is practicable to apply. High speed and potentially fuse saving characteristics (referred to as fast curves) may also be applied to overcurrent and earth fault elements on the initial trips.

It is noted that system operators will need to disable the SEF function to prevent unwanted protection operations during some network conditions, such as when feeders are being switched one phase at a time, or when multiple feeders are being operated in parallel, which can lead to significant earth fault current being measured by the protection system. If a recloser does not have a permanent and reliable SCADA connection, the SEF function may be permanently disabled if SEF coverage is provided by at least one upstream protection device.

A SCADA remotely and locally controllable instantaneous setting, often referred to as a live line or work-tag function must also be made available for temporary application.

Line reclosers must be backed up by at least one other protection scheme in the normal network configuration. It is accepted that some legacy networks do not achieve this requirement. Legacy networks must be brought up to this standard during substantial network refurbishment projects where it is practicable to do so.

9.2.4 Fuses

Line fuses may also be applied to protect small segments of distribution feeders. Full-range fuses are considered fail-safe if they are operated within their design limitations, and therefore backup protection is not required for sections of line downstream of a fuse. SEF protection coverage for the fused section of line must be provided by an upstream recloser or the zone substation CB protection.

9.2.5 Sectionalisers

Sectionalisers are switches that coordinate with protection devices to isolate a permanently faulted section of feeder so that a subsequent upstream reclose is successful. Sectionalisers may be employed in conjunction with a recloser to improve reliability of supply. The correct operation of a sectionaliser can be assumed when assessing the short time rating of line conductors.

9.2.6 Through-fault indicators

Where appropriate, through-fault indicators shall be connected to SCADA to provide indication of fault passage to the ADMS. They will normally include detection of overcurrent, earth fault and SEF and shall be set to alarm in conjunction with the upstream protective device in the normal network configuration.

9.2.7 Dedicated supply feeders

Distribution feeders which are dedicated to a small number of specific loads such as shopping centres, or single supplies to high voltage customers may have requirements that differ from the requirements in this standard. The scheme requirements for such supplies will be considered on a case-by-case basis in consultation with the Delivery Manager Secondary Systems.

9.2.8 Double cable feeders

To allow for optimal protection performance, operational flexibility and conductor utilisation, double cable feeders shall be installed with independent leg protections, except those dedicated to supplying capacitor banks and auxiliary supplies. Exceptions to this rule may be approved by the Delivery Manager Secondary Systems in exceptional circumstances. NOTE: two identical conductors fed from a single CB in order to increase the capacity for a single customer are termed “Twin cables” and do not fall under this category.

9.2.9 Automatic reclose

Automatic reclosing of the line is normally applied to overhead feeders for phase and earth faults to significantly improve reliability of supply. Automatic reclose of the line must only be initiated by an overcurrent or earth fault initiated trip and must not be initiated by an SEF initiated trip.

9.2.10 Summary of normal feeder protection schemes

The following table summarises the application of normal feeder protection functions.

Table 18: Normal feeder protection schemes

Application	Relay	Functions
Zone substation circuit breaker	#1	• Overcurrent (IDMT, DT, instantaneous, and operator controlled instantaneous) • Earth fault (IDMT, DT, instantaneous and operator controlled instantaneous) • SEF • TOBAN SEF (optional) • Circuit breaker failure
	#2	• Overcurrent (IDMT, other functions optional) • Earth fault (IDMT, other functions optional) • SEF (optional) • Circuit breaker failure (optional)
Line recloser	N/A	• Overcurrent • Earth fault (residual overcurrent) • SEF • Live line (controllable instantaneous overcurrent and earth fault)
Line Fuses	N/A	N/A
Sectionalisers	N/A	N/A

9.3 Setting and application requirements

9.3.1 Minimum fault sensitivity

In the normal network configuration, including under maximum foreseeable source impedance conditions, or in any planned or unplanned abnormal feeder configuration, the primary protection IDMT overcurrent and earth fault functions must achieve the minimum sensitivity factor (minimum fault level to pick up ratio) as prescribed in Table 19 for a bolted fault of any fault type at the extremities of the protected network, and up to the next downstream protection devices. Exceptions to this rule are only allowed by authority of the System Operator (in accordance with NCB 0642 – Protection Withdrawal Authority).

For new networks, the backup protection must also achieve the sensitivity factor prescribed for backup in Table 19 in the normal feeder configuration, including under maximum foreseeable source impedance conditions. It is accepted that this requirement is not met on some existing feeders. Existing networks must be brought up to this standard in conjunction with refurbishment works if practicable.

Backup protection is not mandatory for temporary abnormal feeder configurations or with a single disabled protection system. In these cases, the sensitivity factor given in Table 19 must be met based on the actual operating condition.

Table 19: Minimum sensitivity factors for distribution feeders

Situation	OC & EF Primary	OC & EF Backup
Normal operation (maximum foreseeable source impedance)	1.5	1.3* *(1.5 for electromechanical relays, new networks only, existing networks to achieve if practicable)
Abnormal configuration or disabled protection scheme (actual source impedance)	1.3* *(1.5 for electromechanical relays)	Not required

It is desirable that higher sensitivity factors be achieved if practicable. Additionally, the IDMT earth fault pickup ideally will achieve a target sensitivity factor of 1.3 for a fault with a fault resistance of 30 Ω if practicable. This is not a mandatory requirement.

9.3.2 Maximum clearing time absolute limits

The following maximum clearing times are applicable to all distribution feeders. Exceptions to this rule are only allowed by authority of the System Operator (in accordance with NCB 0642 – Protection Withdrawal Authority).

Table 20: Distribution feeder clearing time limits (bolted fault)

Situation	OC & EF Primary	OC & EF Backup & CB Fail	SEF
Normal operation (maximum foreseeable source impedance)	2 s (*Note 1)	4 s (new networks only, existing networks to achieve if practicable)	11 s
Abnormal configuration or disabled protection scheme (actual source impedance)	4 s	Not required	11 s

*Note 1: Existing systems which do not meet this requirement may be allowed to continue to operate up to a limit of 3 s in the normal configuration, and without notifying system operations, provided that this issue is raised with the Lead Engineer Network Planning for future rectification in the Distribution Works Program.

9.3.3 Maximum clearance times for plant protection

For new systems, both primary and backup protection must protect any line conductor within the Company's designated short time thermal rating for the relevant conductor based on the conditions given in the table below. This rule applies when both the protection systems and the conductor are new or achieve the current specifications for new systems.

For existing systems, if the requirements for new systems are not reasonably achievable, it is acceptable for primary protection only to protect the conductor within the Company's designated short time thermal rating for the relevant conductor based on the less onerous test conditions given in the table below. The allowable limit may be exceeded by up to 100% based on a risk assessment as directed by the Delivery Manager Secondary Systems.

In planned abnormal or temporary network configurations, including when protection systems are out of service, the requirements for existing systems must be achieved, except that the nominal rating may be exceeded by up to 100%, provided that a Total Fire Ban (ToBan) is not in effect.

Table 21: Overhead conductor short time rating test criteria

Parameter	New system design	Existing system design	Abnormal/temporary configurations
Allowable exceedance limit (I2t)	0%	0% (up to 100% with a risk assessment)	100% (0% on a ToBan day unless subject to a risk assessment for existing system design)
Fault type	All fault types	Phase to phase fault	Phase to phase fault
System voltage	1.1 pu	1.0 pu	1.0 pu
Protection operation	Primary & backup	Primary only	Primary only
Upstream configuration	Normal maximum		Actual
Parallel load	Nil/ignore		
Fault location	Worst case		
Fault resistance	Zero		
Reclose method	Full reclose cycle		
Cooling between reclose	Disregard		
CB operating time	70 ms		

9.3.4 Load stability

It is a high priority that the protection remains secure under loading conditions in the normal configuration, including during temporary and transient network conditions such as cold load levels, motor starts, and transformer inrush. To achieve this, the overcurrent pickup setting will typically be set to at least 120% of the maximum forecast load in the normal network configuration. A setting of 150% or greater is preferred to allow for both unforeseen increases in load, greater margins for cold load, and enhanced network reconfiguration capability. It is also preferred that the pickup be set to at least 120% of any foreseeable abnormal feeder configuration at maximum forecast load.

To achieve a reasonable level of stability for cold load and motor inrush current, the IDMT overcurrent curve will ideally allow for at least 3 times peak load current for a period of 1 second. It is preferred that a level of 6 times be achieved if practicable.

To achieve stability for transformer inrush, the IDMT overcurrent curve will ideally allow for a current of 12 times the largest transformer or transformer bank (if multiple transformers at the one geographical location) for a time of 100 ms. The IDMT earth fault curve will ideally allow for a current of 6 times the largest transformer bank for a time of 100 ms. It is preferred that a factor of 16 times be used if practicable for both overcurrent and earth fault.

9.3.5 Switching stability and earth fault protection

To achieve IDMT earth fault stability under network switching conditions, a minimum setting of 25% of the overcurrent pickup is normally required. At the zone substation circuit breaker, a higher setting up to 60% of the overcurrent pickup is desirable in high load areas where single phase switching will be commonly undertaken. On reclosers, a setting up to 100% of the overcurrent pickup may be required to coordinate with downstream protection devices. These suggested settings for switching stability do not preclude the use of settings outside this range.

9.3.6 Coordination

Full coordination between zone substation transformers and feeder protections is mandatory and there will ideally be a safe coordination margin in the worst-case operating condition (usually with only one transformer in service). The transformer IDMT elements will be set to reset instantaneously if the protection relays support this function.

Full coordination between zone substation CBs and line reclosers, and between line reclosers is normally required, however there are some cases where marginal coordination margins may need to be used to keep feeder clearance times minimal, to protect network plant, or to achieve other higher priority criteria. Reclosers may also be sequence coordinated (rather than time graded). It is acknowledged that miscoordination may occur in the case of intermittent or unusual fault scenarios due to dissimilarities in the relay's characteristics. For example, many reclosers necessarily have a shorter SEF reset time delay than is available at the zone substation circuit breaker and this can result in SEF operation at the zone substation for a fault downstream of a recloser if the fault is intermittent.

Full coordination between zone substation CBs or reclosers and downstream line fuses is also a high priority, though coordination will not normally be achievable in the case of low-level faults that trigger an upstream SEF operation.

Coordination between the line protection devices, and distribution substation fuses or circuit breakers will be achieved as far as practicable, but is not mandatory, particularly if the line protection will have to be substantially degraded as a result. In many situations, coordination margins may have to be tight, or coordination may be compromised particularly for rarer non-bolted fault scenarios. It is acknowledged that in doing this there are risks introduced such as feeder loss of supply, and the potential for unwanted automatic reclose or manual restoration at the substation in the case of rare substation faults. However, priority must be given to minimising the extent of damage and safety risk associated with feeder faults which are substantially more frequent and are more likely to involve public exposure.

9.3.7 IDMT curve types

The normal curve for IDMT overcurrent and earth fault protection will be the IEC Standard Inverse curve. Where it is advantageous, other curve types may be used, but as far as is practicable will be limited to the following:

- IEC Standard Inverse;
- IEC Very Inverse;
- IEC Extremely Inverse; and
- Reclosers may use fuse saving curves on initial shots as appropriate (typically TCC105)

9.3.8 Reset characteristics

IDMT OC and EF as well as SEF functions on overhead feeders must have a delayed reset characteristic applied so that they are not insensitive to intermittent faults. A delayed reset will also normally be applied to underground feeders.

9.4 Zone substation settings

9.4.1 OC & EF settings

The IDMT overcurrent pickup level will normally be set to 400 A unless an alternative setting is reasonably required, for example where the load current and cable ratings are greater than normal, or where fault levels are very low. The time multiplier will be set as appropriate to achieve the protection objectives given elsewhere in this document.

The earth fault pickup setting will be as low as practicable, but high enough so that there is protection stability during cross feeder switching or single phase switching during high load currents. Grading with downstream fuses, particularly line fuses also needs to be considered. A minimum setting of 25% of the overcurrent pickup (typically 100 A) is usually appropriate if there are limited single phase switching points or if single phase switching is not commonly practiced. A maximum setting of 60% (typically 240 A) of the overcurrent pickup is usually appropriate in high load areas where single phase switching will be commonly undertaken.

New feeder protection systems will have a full-time definite-time overcurrent and earth fault high set element set at 3000 A for 100 ms, unless an alternative setting (higher or lower) is appropriate. This setting is considered appropriate for coordination with downstream 100 A K-type expulsion dropout fuses and 100 A HRC fuses.

New feeder protection systems will also have a full-time instantaneous overcurrent and earth fault setting applied at 110% of the maximum fault level at the first downstream protection device in the normal operating configuration. This setting will be applied regardless of if the setting is greater than the theoretical maximum busbar fault level. The Delivery Manager Secondary Systems will provide direction if this setting is unavailable due to relay setting constraints.

9.4.2 Operator controlled instantaneous OC & EF

In addition to full-time high set elements, new systems will also have an operator controlled instantaneous high set element. This will be set as low as practicable but will ideally remain stable for transient conditions to allow the function to be enabled for try back as well as live line work. An overcurrent setting of 250% of the IDMT overcurrent pickup (typically 1000 A), and an earth fault setting equal to the IDMT overcurrent pickup is appropriate unless there is knowledge to the contrary.

Operator controlled high set elements will be enabled at existing sites in conjunction with protection or SCADA refurbishment projects if practicable.

Table 22: Typical feeder overcurrent settings

Parameter	Criteria
General	To be adjusted as per objectives and criteria (Table 30)
IDMT PU	400 A
Full-time highset	3000 A for 100 ms
Full-time instantaneous PU	Pickup 1.1 x maximum fault level at the first substation
Operator controlled instantaneous PU	Pickup at 2.5 x OC PU (e.g. 1000 A for typical feeder)

Table 23: Typical feeder earth fault settings

Parameter	Criteria
General	To be adjusted as per objectives and criteria (Table 30)
IDMT PU	100 A where there are a limited number of single phase switching points, otherwise 240 A.
Full-time highset	3000 A for 100 ms.
Full-time instantaneous PU	1.1 x the maximum fault level of the first substation if this setting is available.
Operator controlled instantaneous PU	Pickup 1 x OC PU (e.g. 400 A on a typical feeder)

9.4.3 SEF settings

SEF will be set in accordance with the below Table. Where an alternative pickup or CT ratio is used, the designer may select an appropriate setting, preferably around 1% of the overcurrent pickup setting to a maximum of 5 A. In-service settings which are not set at the preferred setting, but which are currently set to 5 A or lower need only be adjusted when the next configuration change takes place.

Table 24: Feeder SEF pickup setting requirement

Pickup	CT primary ratio (A)	Preferred SEF setting (if available)	Range of acceptable SEF settings
≥600 A	600/1	4.2 A	4 to 5 A
500 A	500/1	4 A	4 to 5 A
400 A	400/1 or 500/1	4 A	3.5 to 5 A
300 A	300/1	3 A	2.5 to 5 A
250 A	300/1 or 250/1	3 A	2.5 to 5 A

Higher settings may be required in exceptional circumstances. Examples include:

- 22kV feeders with autotransformers and SWER lines (such that earth current returns through the autotransformer and not the zone transformer)
- Where there is a history of SEF tripping in the absence of faults
- Where two feeders are normally operated in parallel (in a ring configuration).

In these circumstances, a pickup setting up to a maximum of 10 A is acceptable, but only to the extent reasonably required.

The SEF trip time delay will be set at 5 seconds on the most downstream device unless a higher setting is required to coordinate with the downstream protection IDMT EF total clearance time with reclose. Upstream devices will have a coordination margin of 1 second, to a maximum relay trip delay time of 10 seconds at the zone substation circuit breaker. Settings may be applied to allow for planned or anticipated future installations.

The SEF element reset time delay will be set to 10 seconds fixed time delay if this is available, or otherwise as high a delay as is available. A simulated disk reset function is also acceptable for existing installations. This reset time delay must not be confused with the trip time delay.

9.4.4 Core balance current transformer settings

Where core balance current transformers are available, a lower setting (typically 1A) may be temporarily applied by SCADA control.

9.4.5 Summary of typical zone substation SEF settings

Table 25: Typical zone substation SEF settings

Parameter	Criteria
Pickup	• As per the SEF setting table. • For feeders with a core balance CT installed, a lower pickup setting (typically 1 A) that is selectable by operator control can be applied.
Time delay	• 5 seconds on the most downstream device (even if this is the zone substation circuit breaker) unless a higher setting is required to coordinate with downstream IDMT EF total clearance time with reclose. The SEF reset time must also be considered. • 1 second grading margin between devices.
Reset timer	• 10 seconds fixed time delay on the ZS CB (existing sites may have an alternative time delayed reset applied).

9.4.6 CB Fail parameters

At new sites, circuit breaker failure protection which initiates a trip of the relevant bus section must be enabled by at least one of each feeder relay's overcurrent and earth fault functions. At least one SEF element will initiate CB Fail if practicable. The CB Fail function will normally be achieved through a current check function with a standard time delay of 200 ms. The check current level must not be higher than the IDMT earth fault pickup level and will ideally be as low as is practicable consistent with secure operation and giving regard to the limitations of the relay and CT ratio. It is accepted that CB Fail protection may not be available for very low-level SEF faults.

9.5 Line recloser settings

9.5.1 Recloser OC & EF settings

The overcurrent pickup setting must be set as sensitive as possible whilst also providing suitable coordination with other protection devices, load current (including an allowance for future growth, reconfiguration and reverse power flow from distributed generation), cold load current, and transient inrush current. Normally, the pickup setting will be between 150% and 200% of the maximum existing (or foreseeable future) load current if this is suitable.

The earth fault pickup will be set in the range 25% to 100% of the overcurrent pickup as required. It will often need to be set close or equal to the overcurrent pickup setting because lower settings may not provide adequate coordination with downstream fuses.

9.5.2 Recloser operator controlled instantaneous trip

Reclosers must be set up with operator controlled instantaneous trip settings for live line work. These settings will normally have the same overcurrent and earth fault pickup, but with an instantaneous trip time.

Table 26: Typical line recloser overcurrent settings

Parameter	Suggested setting method
General	To be adjusted as per objectives and criteria (Table 30).
IDMT PU	1.5x to 2x anticipated peak load current.
Full-time highset	As required
Operator controlled instantaneous	1 x recloser OC PU (or as required to achieve no operation for transient conditions)

Table 27: Typical line recloser earth fault settings

Parameter	Suggested setting method
General	To be adjusted as per objectives and criteria (Table 30).
IDMT PU	As low as practicable, typically 25% to 100% of the OC pickup. May need to be the same or close to the overcurrent pickup to achieve coordination with downstream devices and fuses.
Full-time highset	As required
Operator controlled instantaneous (work tag)	1 x recloser EF PU (or as required to achieve no operation for transient conditions)

9.5.3 Recloser SEF settings

SEF protection will be applied to reclosers, even if the recloser is not SCADA connected in which case it may have its SEF function normally disabled.

The recloser SEF pickup setting will be equal to or lower than the setting at the zone substation if practicable, though some reclosers have a lower limit which can be higher than that at the zone substation in which case the minimum setting available must be applied. Higher settings may be required in some instances if there is a history of SEF tripping in the absence of faults, or if two feeders are normally operated in parallel (in a ring configuration). In these cases, settings up to a maximum of 10 A may be applied, but only if reasonably required.

The SEF trip time delay will be set at 5 seconds on the most downstream device. Upstream devices will have a coordination margin of 1 second, to a maximum trip delay time of 10 seconds. It is noted that a higher trip time delay may be required to coordinate with inverse definite minimum time (IDMT) earth fault protection in some cases, but the 10 seconds limit will still apply.

The SEF element reset time delay will be set to 10 seconds fixed time delay if this is available, or otherwise time delayed as directed by the Delivery Manager Secondary Systems. A simulated disk reset function is also acceptable for existing installations if a fixed time delay is not available. This reset time delay must not be confused with the trip time delay.

Table 28: Typical line recloser SEF settings

Parameter	Suggested setting method
Pickup	Equal to or less than the feeder pickup (or the minimum available). As required for stability (4 A maximum unless this will be unstable)
Time delay	5 seconds on the most downstream device, unless higher is required to grade with downstream IDMT EF total clearance time with reclose. The SEF reset time must also be considered in this. 1 second grading margin between devices.
Reset timer	10 seconds fixed time delay if available, otherwise time delayed as directed by the Delivery Manager Secondary Systems.

9.6 Automatic reclose settings

9.6.1 General

Automatic reclose will normally be applied to feeders with a substantial distance of overhead powerline to improve the reliability of supply. Whilst some feeders will not normally have auto-reclose enabled, for design standardisation, and because feeder configurations can change over time, the function will normally be made available on all feeder protection devices. System Operators will control the application (on or off) of the automatic reclose function as required and in accordance with operational procedures.

Auto reclose is normally initiated by the overcurrent and earth fault functions in the normal mode only and must not be initiated by the SEF function. Automatic reclose must not be configured to operate when the operator controlled high-set is enabled or in single shot mode.

To avoid damage to electronic equipment, allow large synchronous motors to be disconnected, and allow for upstream protection relays to reset, the reclose dead time must not be less than 5 seconds.

The reclose dead time (intentional delay) will not normally exceed 10 seconds. The total fault sequence time, from the start of the initial fault to the end of the final fault prior to lockout, generally must not exceed 30 seconds for a permanent bolted fault. It is however acceptable for a distribution feeder automation scheme to exceed these values if it is reasonably required to achieve proper operation; however, the total sequence time to lockout must not exceed 60 seconds.

Further consideration must be given to reclose on feeders with line capacitor banks. Allowance may be required for the discharge time of the capacitors before reclosing occurs.

9.6.2 Feeder CB automatic reclose

Automatic reclose of the zone substation circuit breaker is undertaken by the SCADA system, not the protection system. The standard approach is a single reclose after a 10 second time delay. A reclaim time of 20 seconds will normally be used.

9.6.3 Line recloser automatic reclose

Line reclosers will be configured with up to 3 automatic reclose attempts (i.e. 4 trips in total). If there are no limitations to the number of recloser shots (e.g. a conductor short time thermal rating limitation), the line recloser will be set with at least 2 reclose attempts. Optimum reliability performance of a single recloser is likely to be achieved with 2 fast (e.g. TCC105) and 2 slow shots.

As a minimum, a recloser needs at least one reclose, usually a fast curve, followed by a reclose with a delay or slow curve. If practicable, the fast curve must operate faster than downstream line fuses to prevent these fuses from operating for transient faults. This is referred to as fuse saving. The slow curve must if practicable coordinate with the downstream line fuse and allow it to operate for permanent faults.

If there is a sectionaliser downstream of a recloser, the recloser must have at least 3 shots (2 reclose attempts) to allow for a single reclose of the segment downstream of the sectionaliser, followed by a reclose after the sectionaliser has opened if the fault is permanent.

An alternative to full time-grading between reclosers is for the upstream recloser to have at least one more operation in its sequence than the downstream recloser. Typically, a maximum of four reclosers can be connected in series.

The recloser curve types and dead times will be applied as per the following Table.

Table 29: Standard recloser sequences

# shots	Combinations	Dead time delay	Reclaim time
2	2 slow 1 fast, 1 slow	10 s	30 s
3	3 slow 1 fast, 2 slow 2 fast, 1 slow	10 s, 10 s	
4	4 slow 1 fast, 3 slow 2 fast, 2 slow 3 fast, 1 slow	5 s, 8 s, 8 s	
Fast: Fuse saving type curve (e.g. TCC105), Slow: IEC IDMT curve			

9.7 Summary of OC and EF setting criteria

The table below provides guidance for determining the appropriate settings and for balancing competing requirements.

Table 30: OC and EF setting criteria summary

Priority	Description	OC Criteria	EF Criteria
1 (Mandatory)	Detect and clear bolted faults	$FL_{min} \geq 1.5 \times PU\ (or\ 1.3\ for\ nonelectromechanical\ backup/abnormal)$ $t_{clear} \leq 2\ s\ (\leq 4\ s\ for\ backup/abnormal\ configurations)$	
2 (High)	Remain stable for load current and typical inrush in the normal configuration	$PU \geq 1.2 \times Load_{max}(Normal\ config)$ 12x largest transformer bank for 100 ms 3x peak load for 1s	6x largest transformer bank for 100 ms
3 (High)	Coordinate with line protection devices (e.g. reclosers and line fuses)	Appropriate time or sequence coordination	
4 (High)	Protect plant within its short time current rating (primary)	As per test criteria given elsewhere in this document	

5 (Low)	Remain stable for: load current in many non-normal configurations; during single phase network switching; and allow for load growth in the normal configuration	$PU \geq 1.5 \times Load_{max}(Normal\ config)$ If required: $PU \geq 1.2 \times Load_{max}(Abnormal\ config)$	If cross feeder tie exists: $PU_{EF} \geq 0.25 \times PU_{OC}$ or as required for stability under single phase switching
6 (Low)	Minimise fault energy by limiting the clearance time at high fault currents	High set (100 ms clearance time typical)	
7 (Low)	Coordinate with substation and HVC protections <u>for bolted HV faults</u>	Appropriate time or sequence coordination	
8 (Low)	Additional sensitivity to detect and clear <u>some</u> low-level faults.	$FL_{min} \geq 2 \times PU$	$FL_{min}(R_{fault} = 30\Omega) \geq 1.3 \times PU$
9 (Low)	Protect plant within its short time current rating (backup protection)	As per test criteria given elsewhere in this document	
10 (Low)	Coordinate with substation and HVC protections for all faults	Appropriate time or sequence coordination	
11 (Low)	Allow for additional load and conservative residual currents during abnormal switching	Typical: $PU \geq 2 \times Load_{max}(Normal\ config)$ $PU \geq 1.5 \times Load_{max}(Abnormal\ config)$	$PU \geq Load_{max}(Normal\ config)$
12 (Low)	Allow for conservative inrush currents	16x largest transformer bank for 100 ms 12x peak load for 1 s	16x largest transformer bank for 100 ms

Table 31 - Setting criteria definitions

Symbol	Definition
$\boldsymbol{PU}$	The relay minimum pickup current setting
$\boldsymbol{FL_{min}}$	The minimum bolted fault level within the zone of protection (c = 0.9)
$\boldsymbol{FL_{max}}$	The maximum bolted fault level within the zone of protection (c = 1.1)
$\boldsymbol{Load_{max}}$	The peak forecast load current
$\boldsymbol{R_{fault}}$	Fault resistance
$\boldsymbol{t_{clear}}$	Fault clearance time

9.7.1 Actions if certain criteria cannot be met

The following table details the actions to be undertaken if the criteria in Table 30 cannot be met.

Table 32 - Setting criteria action table

Priority	Definition/Actions

Mandatory	Network re-arrangement or augmentation must be immediately instigated to achieve this requirement. The **network must not normally be energised in this state** except under abnormal circumstances covered in NCB 0642 and authorised by the System Operator who must be made aware of the level of protection available.
High	Network augmentation is generally justified. Changes must be planned and implemented as soon as is practicable.
Low	Network augmentation is generally not cost justified but may be in some circumstances. Setting changes to achieve these objectives will generally be implemented at the next available relay maintenance unless a more urgent schedule is warranted.

10 Distribution transformer protection

10.1 Scope

This section applies to Endeavour Energy owned power transformers with a high voltage side which operates at 11 kV, 12.7 kV (SWER), and 22 kV.

10.2 Scheme requirements

10.2.1 Pole substations

Pole substations will be protected by HV fuses as specified in Mains Construction Instruction MCI 0005 (Section 8.2) - Overhead distribution construction standards manual.

10.2.2 Pad mount and indoor substations

Pad mount and indoor substations will be protected by HV fuses and/or circuit breakers as specified in Mains Construction Instruction MCI 0006 (Section 7.2) – Underground distribution construction standards manual.

10.2.3 Step-up and step-down transformers

11 kV to 22 kV step-up or step-down transformers that are 1 MVA or larger require their own dedicated overcurrent and earth fault protections with at least one dedicated circuit breaker on all sides from which there is a source of fault current. Where available, tank and thermal protections will also be used to trip the circuit breaker if it is practicable to do so.

10.2.4 Voltage regulators (autotransformers)

Voltage support step-up autotransformers (to a maximum rating of 1.5 MVA each phase) can be considered part of the overhead distribution network, and do not require any dedicated protection devices provided that the upstream circuit breaker protects the autotransformer within its through fault rating for faults downstream of the autotransformer.

10.3 Setting and application considerations

Distribution transformer circuit breakers will be set to allow for full utilisation of the transformer, and to coordinate with the downstream transformer low voltage protection, and upstream high voltage distribution feeder protection as far as is practicable.

10.4 Record keeping

LAN equipment and cabling are to be recorded on the appropriate station drawings and cable schedules as per the requirements of SDI 526 – Design of Substation Secondary Systems.

11 Underfrequency load shedding (UFLS)

11.1 Scope

This section applies to underfrequency load shedding (UFLS) systems installed at Endeavour Energy zone and transmission substations.

11.2 Scheme requirements

Underfrequency load shedding systems must be installed in all new zone substations which have a firm capacity of 10 MVA or greater. Substantial protection refurbishments at existing substations will also meet this requirement if practicable.

Installation at smaller zone substations may be warranted in some circumstances. The Grid Engineering Manager must be consulted in this regard during the needs analysis stage of major capital or refurbishment projects to determine if there is a requirement.

Underfrequency load shedding systems will allow for each feeder to be allocated to one of three categories:

- Category 1 (stage 1 trip);
- Category 2 (stage 2 trip); and
- Category 3 (no trip).

The stage 1 and stage 2 trip will each be allocated a unique frequency and time delay setting. The scheme will allow for any feeder to be allocated to any category and for easy re-allocation.

11.3 Setting and application considerations

Underfrequency load shedding schemes must comply with the requirements of the National Electricity Rules, and the direction given by AEMO. The Grid Engineering Manager is responsible for periodically reviewing the level of compliance with load shedding requirements and for reporting the outcome to the Delivery Manager Secondary Systems.

The frequency and time delay to trip settings are part of the protection design which are set at the direction of the Grid Engineering Manager or their delegate.

The allocation of individual feeders to load shedding categories is an operational function and is not considered to be part of the protection design. The Grid Engineering Manager or their delegate has the authority and responsibility for allocating feeders to load shedding categories.

12 Instrument transformers

12.1 Scope

This section applies to instrument transformers associated with the company's high voltage primary plant protection systems at transmission and zone substations. It provides the number of instrument transformers required in each application as well as the performance specifications required to achieve proper protection system operation and redundancy. It applies only to the individual instrument transformers, and not to the associated equipment or instrument transformer housing. The requirements for the associated equipment or housing (for example, the insulation rating of post current transformers) are not contained within this Standard.

12.2 Instrument transformer definitions

Term	Definition
Accuracy limit factor (ALF)	The ratio of the rated accuracy limit primary current to the rated primary current.
Burden	The impedance connected to the CT secondary winding.
Dimensioning factor (Kx)	A factor to indicate the multiple of rated secondary current occurring under power system fault conditions, up to which the CT is required to meet performance requirements.
Exciting current (Ie)	The excitation current at the rated knee point voltage.

Instrument Security Factor (FS)	The ratio of rated instrument limit primary current to the rated primary current.
Knee point voltage	The sinusoidal voltage when applied to the secondary terminals of a CT, which when increased by 10%, causes the value of exciting current to increase by 50%.
Rated resistive burden (Rb)	The value of the burden upon which the accuracy requirements are based.
Rated continuous thermal current (Icth)	The multiple of rated current which can be permitted to flow continuously in the primary winding, the secondary winding being connected to the rated burden, without the temperature rise exceeding limits.
Rated primary current	The value of the primary current on which the performance of the CT is based. (May or may not be the continuous thermal rating).
Rated secondary current	The value of the secondary current on which the performance of the CT is based. (May or may not be the continuous thermal rating).
Rated secondary reference voltage	The rms values of the secondary voltage at the CT terminals of a 'P' class CT upon which the performance of the CT is based.
Rated short-time thermal current (Ith)	The rms value of the primary current which a transformer will withstand for one second without suffering harmful effects, the secondary winding being short-circuited.
Secondary winding resistance (Rct)	The CT secondary winding DC resistance in ohms corrected to 75°C or such other temperature as may be specified.
Transient dimensioning factor (Ktd)	The CT dimensioning factor to achieve proper protection performance including allowance for the increase of the secondary linked flux due to the dc component of the primary short circuit current.

12.3 CT classification

New current transformers will be specified as P class, PX or PXR class in accordance with the Australian Standard AS 61869 unless an alternative specification is approved by the Delivery Manager Secondary Systems.

All P class, PX or PXR class CTs must pass type tests and routine tests and be nameplated as required by AS 61869, before being commissioned.

P class CTs will generally be selected for applications where very fast operation and good transient performance is not essential. This generally applies to overcurrent and earth fault protection systems. PX or PXR class CTs will generally be selected for applications where very fast operation and good transient performance is essential. This generally applies to distance and differential protection systems. PXR class CTs are not recommended for high impedance busbar schemes but are preferred for low impedance schemes due to their ability to minimise DC offset caused by remanent flux.

CTs must generally be solid core, however split core CTs are acceptable if there is a legitimate need or benefit.

12.4 CT specification

The table below details the standard parameters required to specify current transformers.

Table 33 - CT specification parameters

Parameter	Specification
Rated frequency	50 Hz

Rated insulation level (where applicable)	As per standard insulation levels in Company Policy 9.2.10 – Network Asset Ratings
Rated primary current	Specification of the rated primary current must comply with SDI501 Table 8. Typically, approximately equal to or greater than the rated primary plant current or maximum load current.
Rated secondary current	1 A at all new sites. 5 A may be used if required for compatibility at existing sites.
Rated continuous thermal current (Icth)	As required to match or exceed the maximum continuous primary plant rating.
Rated short-time thermal current (Ith)	The rated short-time thermal current must be specified in accordance with Company Policy 9.2.10 – Network Asset Ratings.
Class (P)	Specified for maximum tap (across the full secondary winding): • Rated resistive burden (R_b) • Accuracy class • Accuracy limit factor
Class (PX/PXR)	Specified for maximum tap (across the full secondary winding): • Exciting current (I_e) • Knee point voltage (E_k) • Maximum secondary winding resistance (R_{ct})

12.5 Standard CTs

The default standard CTs that will normally be used for new installations are detailed in the tables below. These will meet performance requirements in most cases including with allowance for increases in system fault levels. These CT specifications are for general application by designers and should be reviewed prior to designation in relation to any equipment specification.

The following factors have been considered in the selection of standard current transformers:

- The fault level: both behind the CT location and at the end of the zone, and giving regard to the ultimate fault level
- The system X/R ratio behind the fault
- The CT secondary system time constant (T_2=M/R_2)
- The relay operate time
- The CT burden, including CT resistance, leads and relays
- The CT performance requirements for the specific relay based on the following considerations:
  - The minimum performance requirement specified by the relay manufacturer
  - The IEEE C37.110 application guideline
  - Note: CT saturation after the relay has operated has been accepted

12.6 Standard current transformers

Table 34 - Transmission substation standard CTs

Bay	Ratio	Class	Cores	Remarks
132 kV outdoor All bays	**3000/2000/500/1**	0.05PX300(R_{ct}+2) [Note] I_{cth} = 200%	4	Fault level >31.5 kA or near to large sources of generation
	2000/1000/500/250/1	0.05PX200(R_{ct}+2) [Note] I_{cth} = 200%		Caters for up to 31.5 kA and not near to generation
132 kV indoor All bays	**3000/2000/500/1**	0.05PX300(R_{ct}+1) [Note] I_{cth} = 200%	4	Fault level >31.5 kA or near to large sources of generation
	2000/1000/500/250/1	0.05PX200(R_{ct}+1) [Note] I_{cth} = 200%		Caters for up to 31.5 kA and not near to generation
33/66 kV outdoor All bays	**2000/1000/500/300/1**	0.05PX200(R_{ct}+2) [Note] I_{cth} = 200%	4	
33/66 kV indoor All bays	**2000/1000/500/300/1**	0.05PX200(R_{ct}+1) [Note] I_{cth} = 200%	4	
33/66 kV outdoor Transformer neutral CT	**2000/1000/500/300/1**	0.05PX200(R_{ct}+2) [Note] I_{cth} = 100%	1	

Table 35 - Zone substation standard CTs

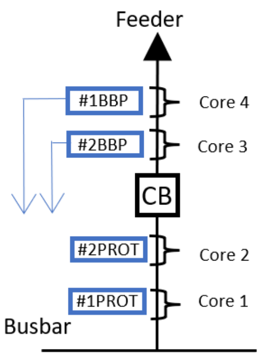
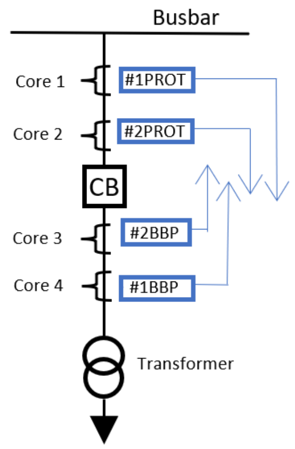
Bay	Ratio	Class	Cores	Remarks
132 kV outdoor All bays	**3000/2000/500/1**	0.05PX300(R_{ct}+2) [Note] I_{cth} = 200%	4	Fault level >31.5 kA or near to large sources of generation.
	2000/1000/500/250/1	0.05PX200(R_{ct}+2) [Note] I_{cth} = 200%		Caters for up to 31.5 kA and not near to generation.
132 kV indoor All bays	**3000/2000/500/1**	0.05PX300(R_{ct}+1) [Note] I_{cth} = 200%	4	Fault level >31.5 kA or near to large sources of generation.
	2000/1000/500/250/1	0.05PX200(R_{ct}+1) [Note] I_{cth} = 200%		Caters for up to 31.5 kA and not near to generation.
66 kV outdoor All bays	**2000/1000/500/300/1**	0.05PX200(R_{ct}+2) [Note] I_{cth} = 200%	4	
66 kV indoor	**2000/1000/500/300/1**	0.05PX200(R_{ct}+1) [Note]	4	

All bays		I_{cth} = 200%		
33 kV outdoor All bays	**2000/1000/500/300/1**	0.05PX200(R_{ct}+2) [Note] I_{cth} = 200%	3 (Fdr) 3 (Trf) 2 (B/S)	High fault level sites
	1000/800/300/1	0.05PX100(R_{ct}+3) [Note] I_{cth} = 200%		Typical sites
33 kV indoor All bays	**2000/1000/500/300/1**	0.05PX200(R_{ct}+1) [Note] I_{cth} = 200%	3 (Fdr) 3 (Trf) 2 (B/S)	High fault level sites
	1000/800/300/1	0.05PX100(R_{ct}+2) [Note] I_{cth} = 200%		Typical sites
11/22 kV indoor Transformer	**2000/1**	0.15PX100(R_{ct}+1) [Note] I_{cth} = 200% & 0.15PX50(R_{ct}+1) [Note] I_{cth} = 200%	2 (Busbar side) & 1 (Trf side)	Conventional
11/22 kV indoor Transformer	**2000/1**	0.15PX100(R_{ct}+1) [Note] I_{cth} = 200%	2 (1 for Trf) & (1 for Trf + bus)	IEC61850
11/22 kV indoor bus section	**2000/1**	0.15PX50(R_{ct}+1) [Note] I_{cth} = 200%	2	Conventional
11/22 kV indoor bus section	**2000/1**	0.15PX100(R_{ct}+1) [Note] I_{cth} = 200%	2	IEC61850
11/22 kV indoor Feeder (Typical)	**600/1** **2000/1**	2.5VA 5P 20 I_{cth} = 200% & 0.15PX50(R_{ct}+1) [Note] I_{cth} = 100%	2 (busbar side) & 1 (line side)	Conventional
11/22 kV indoor Feeder (Typical)	**600/1** **600/1**	2.5VA 5P 20 I_{cth} = 200% & 0.15PXR113(R_{ct}+1) I_{cth} = 200%	1 (busbar side) & 1 (line side)	IEC61850
11/22 kV indoor Feeder (Double cable retrofit)	**800/400/1**	5VA 5P 50 I_{cth} = 200%	2 split cores (1 per leg)	Conventional

11/22 kV indoor Feeder (Double cable)	**600/1** **2000/1**	2.5VA 5P 20 I_{cth} = 200% & 0.15PX100(R_{ct}+1) Note I_{cth} = 100%	2 split cores (1 per leg) & 1 (line side)	IEC61850
11/22 kV Feeder Core Balance	**100/1**	0.005PX0.1R0.21 I_{cth} = 240% FS < 20 Split core	1	Core Balance CT – used only where applicable
11/22 kV Transformer neutral	**2000/1**	0.15PX100(R_{ct}+2) Note I_{cth} = 100%	1	

Note: PXR class CT is preferred for low impedance protection schemes for line, transformers and busbar. PXR class is not recommended for high impedance unit protection schemes.

Table 36 - CTs typical arrangement

<table>
<tr><th colspan="3">Typical Arrangement</th></tr>
<tr><th>Arrangement</th><th>Feeder</th><th>Transformer</th></tr>
<tr><td rowspan="3">Dead Tank CB</td><td>
</td><td>
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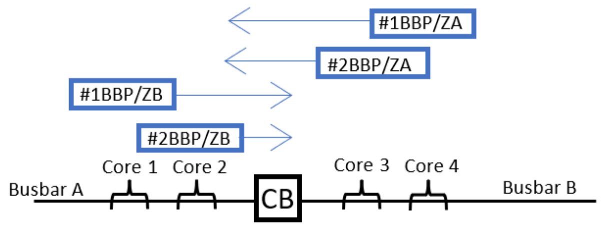
<tr><th colspan="2">Bus Section</th></tr>
<tr><td colspan="2">
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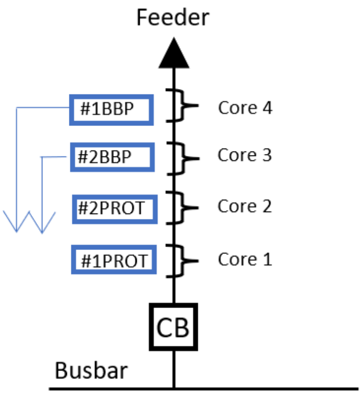
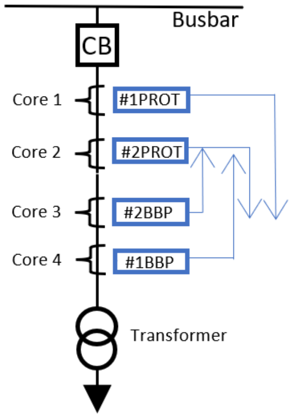
<table>
<tr><th colspan="3">Typical Arrangement</th></tr>
<tr><th>Arrangement</th><th>Feeder</th><th>Transformer</th></tr>
<tr><td rowspan="3"></td><td>
</td><td>
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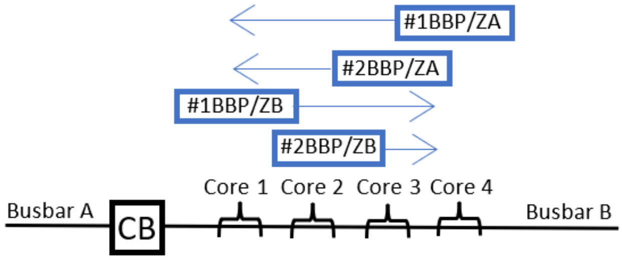
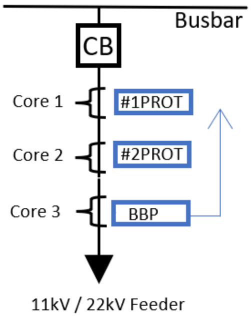
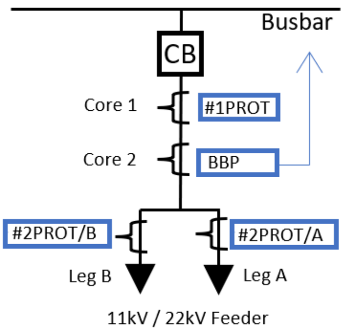
<tr><td colspan="2">
</td></tr>
<tr><td rowspan="4">11/22kV Conventional sites</td><th>Typical Feeder</th><th>Double cable Feeder</th></tr>
<tr><td>
</td><td>
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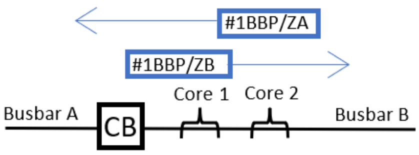
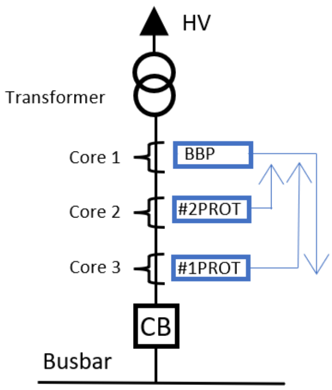
<tr><th>Bus Section</th><th>Transfromer</th></tr>
<tr><td>
</td><td>
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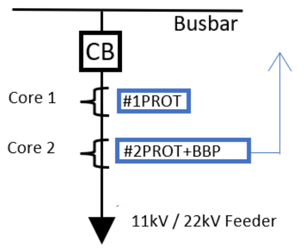
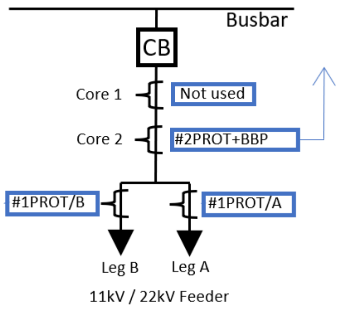
<tr><th>11/22kV</th><th>Typical Feeder</th><th>Double cable Feeder</th></tr>
</table>

<table>
<tr><th colspan="3">Typical Arrangement</th></tr>
<tr><th>Arrangement</th><th>Feeder</th><th>Transformer</th></tr>
<tr><td rowspan="3">IEC61850 sites</td><td>
</td><td>
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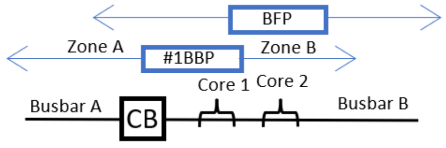
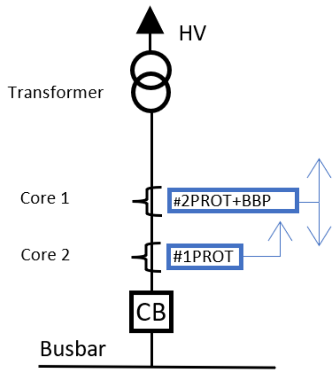
<tr><td>Bus Section</td><td>Transfromer</td></tr>
<tr><td>
</td><td>
</td></tr>
</table>

12.7 Non-standard CT’s

There will be some circumstances, particularly with regards to augmentation of existing sites where standard CTs cannot be accommodated. It is acceptable to utilise site-specific CT specifications where this is reasonably required.

In such cases, the Protection Engineer or Protection Specialist must make a written recommendation to the Delivery Manager Secondary Systems with the basis for the recommended abnormal CT specification. This recommendation must address the following:

- Confirm that the proposed CT has suitable ratings to permit current and reasonably foreseeable future normal and cyclic loading, reasonable emergency/short term loading, and short time (fault) current rating.
- Confirm that the proposed CT meets protection performance requirements under current and reasonably foreseeable future conditions including for variations in the fault level, X/R ratio, primary system configuration, and relay make/model. Note: the reasonably foreseeable conditions which have been considered or are permissible should be documented and included in the recommendation.
- This written recommendation shall be signed and forwarded to the Delivery Manager Secondary Systems for approval and shall be kept in the substation file notes.

12.8 Core Balance CTs

Core balance CTs are used on distribution feeders where very low sensitive earth fault settings are required. These CT’s do not strictly conform to PX class specifications, but the performance is based on the PX performance parameters.

12.9 VT Performance requirements

New voltage transformers will be specified, pass type tests and routine tests, and be nameplated in accordance with the Australian Standard AS 61869 unless an alternative specification is approved by the Delivery Manager Secondary Systems.

The following voltage transformer performance specification shall be applied unless otherwise shown to be inadequate by a Protection Engineer or Protection Specialist. This written recommendation shall be signed and forwarded to the Delivery Manager Secondary Systems for approval and shall be kept in the substation file notes.

Table 37 - VT specification parameters

Nominal system voltage	11 kV	22 kV	33 kV	66 kV	132 kV
Rated primary voltage	11 kV / √3	22 kV / √3	33 kV / √3	66 kV / √3	132 kV / √3
Rated secondary voltage	110 V / √3	110 V / √3	110 V / √3	110 V / √3	110 V / √3
Accuracy class	3.0P [Note]	3.0P [Note]	3.0P [Note]	3.0P [Note]	3.0P [Note]
Rated burden (for each secondary output)	50 VA	50 VA	50 VA	50 VA	50 VA

Note: VT accuracy can be dual class such as 0.2/3P if also required for metering use.

13 Authorities and Responsibilities

General Manager Safety and Operations has the authority and the responsibility for:

- approving this Standard, including any variations.

Head of System Operations has the authority and responsibility for:

- making recommendations to General Manager Safety and Operations in respect to this instruction.

Secondary Systems Manager has the responsibility for:

- keeping this instruction up to date;
- ensuring that the requirements of this instruction are adhered to in the design and construction of substation communication systems; and
- approving any site-specific variations to the design philosophies and standards specified within this document.

Endeavour Energy employee and/or contractors have the responsibility for:

- ensuring that the requirements of this instruction are met;
- working in accordance with local and statutory requirements;
- ensuring that public safety is not compromised; and
- working in accordance with Endeavour Energy's Electrical Safety Rules.

Regional Transmission Managers have the responsibility for:

- ensuring that Endeavour Energy personnel and/or contractors engaged to perform the work have appropriate authorisations.

14 Document Control

Documentation Content Coordinator:	Secondary Systems Manager
Documentation Distribution Coordinator:	Branch Process Coordinator

Appendix A Protection Definitions

Below is a list of recommended terms to enable internal and external customers of Endeavour Energy to discuss protection schemes with a mutual understanding of the terms used to describe schemes and their performance parameters.

Term	Definition
Apparent impedance	The system impedance from the relay measurement location to the fault location as measured by a distance relay. This impedance can be very different to the actual impedance due to mutual coupling and remote infeed effects.
Arc resistance	The impedance of an arc.
Arcing fault	A fault which is not a bolted fault, that is, some or all the fault current flows through the air and therefore an arc exists. In these cases, there may be substantial fault resistance.
Arcing time	The time between the instant of arc initiation at the circuit breaker contacts and final extinction on all poles.
Auto	Enabled, on, or operational.
Auto reclosing	The automatic closing of a circuit breaker to restore an element to service following automatic tripping of the circuit breaker.
Backup protection	Only to be used in the context of a fault or fault zone: A backup protection scheme is a scheme which is set in a way that it would operate to clear that fault or a fault within that zone, only in the case that one or more other protection schemes have failed to operate as intended. Note: a protection scheme can simultaneously be a primary protection for one zone and a backup protection for another zone.
Balanced voltage protection	A differential protective system where equal current flow into and out of the protected zone produces no net circulating current through the CT secondary circuit and a series connected relay.
Bay controllers	A device with control and monitoring functions, but without protective functions.
Biased relay	A relay in which the characteristics are modified by the introduction of some quantity other than the actuating quantity, and which is usually in opposition to the actuating quantity.
Blinder	A relay, whose characteristics, when plotted on an R-X diagram, is a straight line crossing the characteristic of another relay and arranged to prevent tripping on one side of its own characteristic.
Blind spot	A point in the system where a fault will not be isolated by the protection which tries to clear the fault. This usually occurs between a CB and the CT's associated with that CT.
Blocking protection	A protection system associated with a signalling system in which the receipt of a signal blocks the locally initiated tripping signal.
Blocking signal	A signal that is used to prevent or delay tripping.
Bolted fault	A fault where there is zero contact resistance at the point of fault.

Breaker failure	The failure of a circuit breaker to operate or to interrupt a fault.
Breaker failure protection	A protection system that protects a facility against non-operation of a circuit breaker that is required to open to clear a fault.
Characteristic angle	The angle between the vectors representing two of the energising quantities applied to a relay and used for the declaration of the performance of the relay.
Characteristic impedance ratio (CIR)	The maximum value of the system impedance ratio up to which the relay performance remains within the prescribed limits of accuracy.
Check relay	A relay forming part of a protection system that confirms the presence of a faulty condition, independently of other detectors and allows a trip command to be issued.
Check zone	The term applied to the non-selective part of a multi-zone bus protection system, supervising current flow at the terminals of the complete station. Tripping is conditional on operation of both the check and discriminative zone.
Cold load	The temporary increase in load current when supply is restored after a substantial period, which is generally due to motor starts, hot water systems, and thermostatically controlled loads (for example cooling and heating) that would not normally all be on simultaneously.
Coordination	See discrimination.
Critical (fault) clearance time	Critical fault clearance time refers to the maximum total fault clearance time that the system can withstand without exceeding stability limits.
Cross-country fault	Simultaneous flashover to earth of two different phases in different line sections of the same power system, generally at the same time, although not necessarily at the same voltage level.
Current differential relay	A relay designed to detect faults by measuring the current magnitude and phase angle difference between relay terminals.
Dead time	The period between fault interruption and a subsequent reclose attempt.
Differential protection	A protection scheme which operates based on the degree of mismatch of currents at two or more points in the network.
Direct inter-trip	The signal initiated by local protection which, when received at the remote end, trips that circuit breaker without reference to the state of the remote protection.
Discrimination	The ability of a protective system to distinguish between power system conditions for which it is intended to operate, and those for which it is not intended to operate.
Distance protection	A protection scheme which operates based on the apparent measured impedance at the relaying location.
Distance protection with acceleration	This scheme uses an under-reaching Zone 1 distance element to send a signal to the remote end of the feeder in addition to tripping the local circuit breaker. The receive relay contact is arranged to extend the reach of the measuring element from Zone 1 to Zone 2. This accelerates the fault clearance at the remote end for faults that lie in the region between the Zone 1 and Zone 2 reaches. Acceleration schemes are usually only applied to older switched distance relays.
Distribution automation	A technique used to limit the outage duration and restore service to customers through fault location identification and automatic switching.
Double cable feeder	When two independent feeders are connected into a single circuit breaker.
Downstream	Electrically, further from the source of supply.

Dropout	A relay drops out when it moves from the energised position to the de-energized position.
Duplicate protection	The provision of two separate protective systems, at a particular relaying point, either of which can fulfil the required protective function. These are usually referred to as the #1 and #2 protection schemes respectively. Note: duplicate schemes may still use common elements such as VT supply and battery supply.
Earth fault protection	A protective system, which is designed to respond only to faults to earth. This usually refers to residual overcurrent protection.
Electromechanical relay	A protection relay which is based on electromechanical components (rather than electronics or a microprocessor).
External fault	A fault outside the defined zone of protection.
Fault clearance time	The time between inception of fault current and arc extinction.
Fault level	The quantity of fault current, generally referred to with the rms value of the fault current in amps (A) or kilo-amps (kA).
Fault impedance	An impedance, (resistive or reactive), between the faulted power system phase conductor(s) or ground.
Fault type	Any one of the following types of electrical fault with zero impedance in the fault: • three phase to earth fault • three phase fault • two phase to earth fault • phase to phase fault • one phase to earth fault
GOOSE message	GOOSE – messages (Generic Object-Oriented Substation Event) according to IEC 61850 are data packets which are cyclically transferred by way of the Ethernet-communication system in case of event-controlled. They serve to the direct information exchange of the device to each other. The cross-communication between the bay devices is implemented via this mechanism.
Harmonic bias	A method of making differential relays insensitive to magnetic inrush currents, where the harmonics are filtered out and used to provide restraint to the operating quantity.
High-impedance fault	High impedance fault is a relative term which refers to a fault where there is enough fault impedance (usually resistance) substantially reduce the amount of fault current and therefore reduce the sensitivity or protection schemes potentially to the extent that the fault cannot be detected.
IEC 61850	An international communication standard for Ethernet based communication in substations. The objective of this Standard is the interoperability protection and control devices.
Infeed	A source of fault current between a relay location and a fault location.
Inrush current	The temporary increase in line current that occurs when magnetic or capacitive equipment is brought into service. The increase is due mainly to the energy required to establish fields in capacitor banks, transformers, motors and the like.
Instantaneous protection	This term is used to indicate that no intentional time delay is applied. In practice, instantaneous protections in modern protection relays will typically operate their trip contact in the range 10ms to 40ms, leading to a fault clearance time typically in the range 60ms to 120ms.
Instrument transformer	Refers to measuring transformers such as current transformers and voltage transformers.

Intermittent fault	Also referred to as a pecking fault, it is where the current is intermittent or inconsistent in level in such a way that the protection relay continues to pick up and dropout rather than clearing the fault normally.
Intertrip	The tripping of circuit breaker by signals initiated by protection at a remote location.
Inverse time delay relay	A dependent time delay relay having an operating time which is an inverse function of the current or voltage
Inverse definite minimum time (IDMT) relay	An inverse time relay having an operating time that tends towards a constant minimum value with increasing values of current or voltage.
Knee-point voltage	The point on a magnetising curve at which a 10% increase in the sinusoidal voltage applied to the secondary terminals of a current transformer, causes the exciting current to increase by 50%.
Lockout	Automatic reclose equipment has reached a condition of lockout when the next trip function would not produce a further auto reclose until the device has been reset.
Main protection	The protective system which is normally expected to operate in response to a fault in the protected zone (see primary protection).
Malgrading	Malgrading is improper coordination (or grading) between protective devices. This generally results in a larger proportion of the network being disconnected than is required to isolate the fault.
Non-auto	Another term for disabled, off or non-operational.
Numerical relay	A protection relay which uses a microprocessor to execute the protection algorithms. This type of relay usually: • has multiple protection functions • has programmable logic • can be set via connection with a laptop • has communications to SCADA and real-time metered quantities • retains fault records • has a detailed display
Opening time	The time between the application of tripping power to the circuit breaker when closed and the instant of separation of contacts.
Operating time	The time between fault initiation, and relay operation.
Overreach	The condition where the apparent impedance as measured by the relay is lower than the real impedance. The relay therefore misjudges the fault to be closer to the relaying point than it is.
Pecking fault	Also referred to as an intermittent fault, it is where the current is intermittent or inconsistent in level in such a way that the protection relay continues to pick up and dropout rather than clearing the fault normally.
Permissive intertrip	The trip signal initiated by local protection which, when received at the remote end of the protected section, permits the remote protection to trip the associated circuit breaker.
Permissive overreaching transfer trip (POTT)	Permissive overreach transfer trip scheme. In this end-to-end communications aided distance scheme, Zone 2 at the local end operates instantaneously if the remote end zone 2 element picks up, as well as under some other conditions (for example, if the remote end circuit breaker is open).
Permissive underreach transfer trip (PUTT)	A distance scheme utilised to provide faster clearance for remote faults. This scheme uses an under-reaching Zone 1 distance element to key a transfer trip signal to the remote end where it is supervised by the over-reaching Zone 2 distance elements.
Pick-up	The level of characteristic quantity at which a protection relay will begin to operate.

Polarising voltage	The input voltage to a relay that provides a reference for establishing the direction of the operating current and in the case of a distance relay, the impedance to a fault.
Power swing	A transient power flow due to change in relative angles of generation on the system caused by a change in transmission or generation configuration.
Primary protection	Only to be used in the context of a particular fault or fault zone: The primary protection scheme is the scheme which is set so that it will operate before any other protections for that fault or fault zone. Note: a protection scheme can simultaneously be a primary protection for one fault or fault zone and a backup protection for another fault or fault zone.
Protection scheme	A protection scheme consists of several protection components protecting a specific zone which generally trip a specific trip coil.
Reach	Refers to how far into the network a protection scheme can potentially detect a fault. This is generally used in the context of the impedance reach of a distance protection scheme.
Reclaim time	The time following a successful closing operation which must elapse before the auto-reclose scheme will fully reset the auto-reclose sequence.
Reclose cycle	The entire reclose cycle for a permanent fault, from the initiation of the fault to device lockout.
Remote infeed	Where there is a source of fault current in front of a distance relay but behind the fault point. Under these circumstances, the relay will underreach.
Resetting value	The value of the current at which the relay begins to reset.
Restricted earth fault (REF)	Restricted earth fault (protection). This is a differential scheme across only a single star winding of a transformer.
Reach	The impedance corresponding to the far end of a distance zone.
Reset time	The time, which elapses between the disappearance of the abnormal conditions which caused the operation of the protection relay and restoration of the protection to its initial condition.
Residual current	The vectorial sum, in a multi-phase system, of all the line currents.
Residual voltage	The vectorial sum, in a multi-phase system, of all the line-to-earth voltages.
Reverse reach	The impedance range of a distance relay in the direction opposite to that of principal concern.
Secondary injection	Application of the actuating quantity to a protection relay directly, rather than via the primary circuits of current or voltage transformers.
Secondary protection	A protective system intended to supplement the primary protection in case the primary system is ineffective, or to deal with faults in those parts of the power system that are not readily included in the operating zones of the main protection (see backup protection).
Selectivity	The ability of a protection system to detect a fault within a specified zone of a network and to trip the appropriate circuit breakers to clear this fault with a minimum disturbance to the rest of the network. Selectivity is normally achieved through time grading or signalling between protection schemes.
Sensitivity	A measure of the minimum operating quantity, for example, current/voltage, necessary to cause operation of a relay or protection system.
Sensitivity factor	The ratio between the applicable minimum bolted fault level and the protection pickup level.

Sequence grading	Sequence grading is where an upstream recloser does not grade adequately with the downstream recloser by trip time, but by having at least one extra reclose in its sequence.
Sequential tripping	A situation where one or more relay terminals of a line cannot detect an internal line fault, typically because of infeed, until one or more terminals has already opened and removed the infeed.
Short time current rating	The maximum thermal rating, considering both current, and the duration of time at that current, that a piece of equipment can withstand when carrying fault current, without exceeding the temperature limits prescribed by the manufacturer or in the company's standards.
Source impedance	The Thevenin equivalent impedance of an electrical system at the relevant terminal.
Spurious trip	An incorrect and unwanted protection scheme operation which has needlessly isolated an un-faulted healthy section of the network.
Stability (relay)	The quality whereby a protective system remains inoperative under all conditions other than those for which it is specifically designed to operate.
Starting relay	A unit relay, which responds to abnormal conditions and initiates the operation of other elements of the protective system.
Static relay	An electrical relay in which the designed response is developed by electronic, magnetic, optical, or other components (without mechanical motion or a microprocessor).
Synchronism check	A system to confirm that two points of the system are in synchronism. This is usually applied across a circuit breaker.
System impedance ratio (SIR)	The ratio of the power system source impedance to the impedance of the protected zone.
System stability	Refers to the dynamic stability of power system generation interactions through the transmission network.
Switch onto fault protection	This is a function which maintains near instantaneous protection operation if a fault exists immediately after the feeder is energised by the circuit breaker closure.
Sympathetic tripping	The phenomena where an un-faulted device trips for a fault on a nearby device, usually caused by current inrush on the device after the faulted feeder's interrupting device opens and the system voltage returns to normal.
Through fault	The current flowing through a protected zone to a fault beyond that zone.
Transfer tripping	A tripping of circuit breaker(s) by signals initiated by protection at a remote location.
Underreach	The condition where the apparent impedance as measured by the relay is higher than the real impedance. The relay therefore misjudges the fault to be further from the relaying point than it is.
Upstream	Electrically closer to the source of supply.
Unit protection	A protective system which is designed to operate only for abnormal conditions within a clearly defined zone of the power system.
Weak infeed	In the context of a distance permissive overreach transfer trip (POTT) scheme, weak infeed is the condition where there is insufficient fault current at one end of a feeder to trigger a distance zone 2 operation which compromises the operation of the fast-permissive overreach transfer trip at the other end. This is usually overcome with additional relay functions.
Zone acceleration	The action of speeding up the operation of a distance relay that would otherwise be time delayed.

Zone (of operation)	The section of network for which a particular protection scheme is intended to provide protection coverage.

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