Branch Procedure: Distribution Protection Guidelines CEOP8002.02

For questions regarding or permission to release this Policy, please contact Essential Energy's Chief Risk and Compliance Officer.

If working from a printed copy of this document, check Policy Alerts and the Policy Library regularly for updates.

9 March 2020 – Original Issue
Approved By: Head of Asset Management
Next review date: March 2023

UNCLASSIFIED

CONTENTS

1.0 PURPOSE

This Operational Procedure sets out the general requirements for protection systems installed on Essential Energy's distribution system.

The guidelines in this document cover Essential Energy's Distribution high voltage systems (6.35kV, 6.6kV, 11kV, 22kV, 33kV, 12.7kV SWER, 19.1kV SWER).

In special cases both CEOP8002.01 and CEOP8002.02 should be referred to in order to determine the most appropriate protection requirements. An example would be locations where a primary distribution feeder may link zone substations or a hybrid feeder.

This document does not preclude the installation or maintenance of protection that exceeds the requirements of this Procedural Guideline; or protection that does not completely meet the requirements of this Procedural Guideline where special considerations exist. In cases where the requirements of this guideline cannot be meet then this must be documented and approved by the relevant Network Planning Manager.

1.1 Role of Protection

While it is not possible to eliminate risk to personnel and livestock from power lines and equipment energised at the voltages covered by this document, an important role of protection equipment is to reduce the level of such risk to an acceptable minimum. Protection equipment should be designed to detect and clear all faults on the high voltage system rapidly while maintaining supply to the largest possible proportion of the electricity supply system in a manner that avoids (wherever possible) danger to personnel or livestock or damage to equipment.

Whenever possible all faults shall be seen by a backup protection device as detailed within this document, with the exception of network assets protected by fuses.

Protection schemes applied to Essential Energy's high voltage distribution system are not normally set to protect against overload conditions unless specifically required. To achieve this, the protection scheme must be designed to:

- detect all faults (where possible) that can occur within the protected zone;
- clear the fault as quickly as practical;
- discriminate (isolate the minimum proportion of the system consistent with clearing the fault);
- protect EE network and equipment;
- be reliable (operate when it is required to); and
- be secure (not operate when it is not required to).

It is not always possible to achieve all these goals. In particular, the goals of reliability and security can conflict. If all goals cannot be achieved, then the minimum requirement is that the protection must detect and clear all faults.

HV Equipment must never be left energised without adequate protection. If in any instance the normal protection equipment is out of service, the equipment must either:

- be de-energised; or
- be energised from a source that can provide adequate protection; or
- be provided with a backup or alternative temporary protection.

2.0 ACTIONS

2.1 Protection Design

All protection design shall comply with the following standards:

- IEC 61000 Electromagnetic Compatibility;
- IEC 60255 Electrical Relays;
- appropriate Australian Standards, including AS/NZS 3000 (SAA Wiring Rules);
- the National Electricity Rules;
- CEOP8002.01 Branch Procedure: Transmission and Sub-transmission Protection Guidelines;
- CEOP8002.02 Branch Procedure: Distribution Protection Guidelines.

When completing distribution protection design, consideration should be given to CEOP8002.01 Subtransmission Protection Guidelines, to ensure protection grading with zone substation equipment can be maintained.

Where practical, protection systems should be designed to achieve the following objectives:

- to detect all short circuit faults between phases and/or phase(s) and earth;
- to detect abnormal operating conditions which may lead to failure of the network or an unsafe condition arising;
- To consider all reasonable network states including (but not limited to)
    - System normal, minimum and maximum fault levels
    - Alternative network switching configurations that are likely to occur

- to allow the primary system being protected to operate within its rated voltage range and carry its rated normal and emergency load currents, without the protection system operating, failing or being damaged;
- to disconnect the faulted part of the network from the rest of the system in the minimum practical time in order to:
    - minimise damage to the equipment and remainder of the network.
    - minimise the probability of injury to personnel and livestock exposed to the faulty equipment or to the faulted part of the network.
    - minimise the probability or extent of damage to Essential Energy's property or to other person's property as a result of the fault.
    - minimise the extent and duration of interruption to supply as a result of the fault.

- to ensure compliant step and touch potentials on the faulted network in conjunction with the earthing system
- to operate in a selective manner so that the minimum amount of the network is taken out of service after a protection operation
- to be as reliable as possible, within cost-justifiable limits. To this end, duplicate or back-up protection systems will be required in many situations
- to ensure that allowance is made for future growth in the network and changes in customer load requirements.

2.2 Protection General Requirements

2.2.1 Protection Scheme Selection

Essential Energy shall apply the following minimum protection schemes as shown in Table 1. Application detail is provided below.

Table 1: Protective Devices

Plant	Protective Devices
Distribution Feeders (CBs & relays)	IDMT OC, NPS & EF, SEF, Auto-reclose
Distribution Feeders (Field)	Automatic reclosers, sectionalisers and line fuses should be installed in line with these guidelines. Remote backup protection should be applied by source side devices.

2.2.2 Fault Clearance Times

Fault clearance times must be as short as possible and be short enough to prevent avoidable damage to personnel or plant. The total clearing time - the time for a permanent fault to be cleared from the system - will vary depending on fault levels and number of automatic reclosers used on the system. See Attachment A for the method of calculating total clearing time.

Table 2 shows the maximum protection operating times from fault inception to circuit breaker trip initiation times for zero impedance faults under normal conditions on the Essential Energy distribution network.

Table 2: Protection device operating times

Protection operating times from fault inception to circuit breaker trip initiation should wherever practical not be greater than:

Protection device operating times (ms)			
Nominal Voltage	**Source End Fault Location**	**Remote End Fault Location**	**Backup**
33kV	1000	2000	4500
22kV and below*	1000	-	-
SEF	10,000	10,000	-

*Note: This includes all SWER networks

Whilst consideration should always be given to meeting the protection device operating times in Table 2, the justification must be financially viable based on the risk involved in not meeting these protection device operating times.

2.2.3 Distribution Protection

Protection installed to protect Essential Energy distribution equipment shall be designed to comply with the protection requirements of Table 1 and should be coordinated with the protection on source and load side equipment. Fault clearance times referred to in Table 2 should (wherever practical) be achieved and in all cases be as fast as practical to maximise quality of supply.
While all Primary Protection schemes remain in service there should be complete discrimination for all faults. There may be a loss of discrimination under backup protection, but this should be kept to a minimum.

Protection schemes applied should minimise voltage fluctuations experienced by other customers. The use of instantaneous settings can assist with this aim.

2.2.4 Primary Protection

The Primary Protection scheme shall be ‘stand-alone’ protection designed for high reliability, security, and discrimination. The role of this protection is to clear any fault in the fastest possible time.

2.2.5 Backup Protection

Backup Protection shall be designed for reliability and security. The role of Backup Protection is to be available if the Primary Protection is unavailable (due to repair or maintenance etc.) or fails to operate. It shall then clear any fault in the protected zone in as short a time as is necessary.

2.2.6 Alternative Network Arrangements

When the network is not in its normal arrangement, the minimal protection requirements which would need to be satisfied would be the backup protection requirements. This would require all protective devices to protect assets in the primary zone with a minimum 1.5 operating factor. This requirement is based on the understanding that generally the network would be in an abnormal state as a result of a network constraint and would only occur for relatively short periods (hours to days) for either planned or unplanned events while restoration/rectification work occurs.

When the alternative arrangement is used for extended periods (months or more) and regularly, for example during high load periods, the protection scheme should be designed to consider these arrangements as part of the normal operation of the network.

2.2.7 33kV distribution feeders and hybrid subtransmission networks

Essential Energy utilises 33kV as both a subtransmission and distribution voltage across its network. In some circumstances a 33kV feeder can be a hybrid, supplying/ interconnecting Zone Substations as well as supplying distribution customers via direct connection to the 33kV. Due to these conditions’ responsibility for determination of protection setting’s/ applied philosophy can be split between the Network Protection Group (applying CEOP8002.01) and Network Planning (applying CEOP8002.02).

The definitions and responsibilities relating to these networks are.

33kV Subtransmission

Feeders which supply/ interconnect between electrical/ terminal stations and/ or zone substations and have no distribution customers connected directly to them.

The Network Protection Group shall have responsibility for these feeders including any field Reclosers that are installed.

33kV Distribution

Feeders which supply distribution customers only and do not supply and or interconnect electrical/ terminal stations and/ or zone substations.

Network Planning shall have responsibility for these feeders including any field Reclosers that are installed. For distribution circuit breakers within zone substations on these feeders, these settings must be agreed upon and applied by the Network Protection Group.

33kV Hybrid Feeders

Feeders which supply/ interconnect between electrical/ terminal stations and/ or zone substations and have distribution customers connected directly to them.

Determination of appropriate settings needs to be agreed by both Network Protection Group and Network Planning. Initiation of the studies can be from either group and will depend on the motivation/project. This is to include all protection devices installed on these feeders, including those not in the main feeder segment (tee's and/or spur's). Creating or modifying and sending of PSAs and setting files for devices located within Zone Substations shall be the responsibility of the Network Protection group. Creating or modifying and sending of PSAs and setting files for field reclosers shall be the responsibility of Network Planning.

2.2.8 Bypass of Reclosers for Maintenance

Bypass of reclosers for maintenance is an important consideration. Reference to CEOP8071 should be made, as to the acceptable reduced operating factor that may be used relevant to the acceptable risk at the time of bypass. This reduced operating factor can only be used for a short period of time to eliminate the long term exposed risk if these reclosers are not maintained.

2.2.9 Distribution Transformers

This term includes SWER isolation transformers and reactors.

The majority of distribution transformers and SWER isolation transformers should be protected with fuses as specified in the Essential Energy Policy Distribution Transformer Fusing CEOP5099.

Most distribution reactors are installed without specific protection, except for surge suppression devices.

It is accepted practice to connect SWER reactors to existing rural substations (preferably non-residential due to noise) using the same substation EDO fuse. This allows for easy detection of faulty reactors or fuses blown by lightning, which might otherwise remain undetected as no customer call would be received for a reactor site.

On SWER systems the general arrangement has an isolating transformer installed at the point where the single wire separates from the two or three phase networks. The isolating transformer will generally be protected by fuses installed on the primary side, which can be used to provide backup protection for Reclosers installed on the secondary (SWER) side.

Linked out (Solid) fusing systems can be used where the cost to improve the protection of a linked-out system does not add sufficient value after appraisal using CECG1140 Appraisal Value Framework.

2.2.10 Distribution Network Capacitor Banks

Distribution network Capacitor bank protection shall consist of appropriate fusing.

2.3 Setting Philosophy – Distribution Schemes

2.3.1.1 Protection – Zone Substation - Distribution Feeders

Distribution feeder protection settings applied to protection devices contained within Zone Substations should be set in accordance with the philosophy covered in this policy (CEOP8002.02). As the distribution circuit breakers are the point of common coupling between the Distribution and Sub-transmission networks, these settings must be agreed upon and applied by the Network Protection Group.

Where protection setting changes are required for a protection device within a Zone Substation, a "Subtransmission Protection Design Request" (CEOF6186) shall be submitted to protection.manager@essentialenergy.com.au. Where the requested protection settings cannot be accommodated due to coordination problems or protection relay limitations, protection settings shall be jointly agreed upon.

The Network Protection Group shall have the responsibility to:

- ensure coordination with upstream Zone Substation protection devices
- ensure adequate backup coverage exists for the failure of the Zone Substation primary distribution feeder protection (where the primary distribution feeder protection is not fully duplicated). Where backup coverage cannot be achieved, a collaborative approach shall be taken to determine whether Zone Substation upgrades or distribution upgrades are the most cost-effective approach.
- create relay or recloser setting files (where applicable) for relays and reclosers within Zone Substations
- produce PSA documentation for protection devices within Zone Substations
- provide fault levels at the Zone Substation busbar
- ensure compliance with CEOP8002.01

Network Planning shall have the responsibility to:

- ensure coordination of the Zone Substation feeder protection with downstream distribution reclosers, relays & fuses
- ensure that the Zone Substation primary distribution feeder protection settings offers adequate primary fault coverage
- ensure that the Zone Substation primary distribution feeder protection settings offer adequate backup fault coverage for the failure of downstream devices, protection bypasses, or alternate network configurations
- ensuring compliance with CEOP8002.02
- provide fault levels within the distribution network to the Network Protection Group (for the failure of the Zone Substation primary distribution feeder protection)

2.3.1.2 Feeder Overcurrent and Earth Fault Protection

OVERCURRENT PICKUP

The primary overcurrent pickup should be set as follows:

a. to be greater than the five-year forecast maximum load X 120% and
b. to be greater than maximum predicted cold load. This predicted value can be obtained in one or more of the following ways:

- by past experience of cold load problems on the feeder;

- by prediction based on the maximum recorded feeder load experienced in a one-year period. In this case, a margin of 10%* should be added to ensure security; and
- by prediction based on the maximum expected feeder load from a load flow study. In this case, a margin of 10%* should be added to ensure security.

***Note:** this margin may be increased for feeders where the backup requirements are met at higher settings.

As an alternative to a permanent overcurrent setting above the cold load, the “Cold Load” multiplier function available within some recloser controllers may be used to ensure the recloser can be closed onto cold load. This function should only be used when absolutely necessary, refer to section 2.3.4.3.

c. To factor in (where possible) alternative feeder arrangements such as:
- Load transfers to adjacent networks that may require a higher pickup setting
- Extended network coverage that may result in lower fault levels

The use of alternate setting groups can also be used to cover these arrangements

d. the overcurrent pickup should be set so as to ensure the following Operating Factors are observed:

Primary Protection Operating Factor
The overcurrent setting should provide a primary Operating Factor of **2.0*** for phase-phase faults based on minimum network conditions. If NPS protection is utilised, the overcurrent primary operating factor can be applied for 3 phase faults only.

***Note:** In the event that the above operating factor cannot be achieved without excessive and/or uneconomic system redesign, then **all** of the following shall apply:

An Operating Factor of **1.5** should be achieved using the normal calculations.

AND

The effect of minimum feeder load current should be used in the software calculation of the minimum current seen by the relay for phase-phase faults. The ratio of this calculated minimum current (including load) to primary relay current pickup should exceed **1.75**.

AND

The impact of the installed embedded generation has been considered in the minimum load current. Embedded generation may in some cases reduce the current flowing through the relay during a fault and hence reduce the operating factor. If significant embedded generation exists on the feeder downstream of the protective device, reduced operating factors should not be applied, unless it can be confirmed by studies, that the protective device cannot be desensitised by the embedded generation not tripping due to its anti-islanding features.

Backup Protection Operating Factor
The overcurrent setting should provide a backup Operating Factor of **1.5*** for phase-phase faults based on normal network conditions. If NPS protection is utilised, the overcurrent backup operating factor can be applied for 3 phase faults only.

***Note:** In the event that the above operating factor cannot be achieved without excessive and/or uneconomic system redesign, then **all** of the following shall apply:

An Operating Factor of **1.35** should be achieved using the normal calculations.

AND

The effect of minimum feeder load current should be used in the software calculation of the minimum current seen by the relay for phase-phase faults. The ratio of this calculated minimum current (including load) to primary relay current pickup should exceed **1.5**.

The feeder overcurrent relay pickup should be set higher than the downstream device(s) overcurrent pickup. This requirement need not apply in instances where it can be justified that time grading is still likely to exist between these devices for all practical fault situations.

AND

The impact of the installed embedded generation has been considered in the minimum load current. Embedded generation may in some cases reduce the current flowing through the relay during a fault and hence reduce the operating factor. If significant embedded generation exists on the feeder downstream of the protective device, reduced operating factors should not be applied, unless it can be confirmed by studies, that the protective device cannot be desensitised by the embedded generation not tripping due to its anti-islanding features.

Overcurrent timing
The overcurrent element timing shall be set as such:

- Above all downstream devices for three phase, phase to phase and earth faults up to the maximum fault levels present at the downstream device location.
- Below upstream devices, up to the maximum fault level that the feeder and upstream device shall simultaneously see for a feeder fault.
- To protect any conductor within its Primary and Backup zone against thermal damage for fault levels that may be experienced by it.

Overcurrent IDMT curves
Where possible, IEC 60255 SI, VI or EI curves are preferred. Other curves may be used where the downstream protection does not suit the use of the preferred curves.

High Set Overcurrent Elements
Where available, high set overcurrent elements may be used, provided that the element is not capable of reaching to any downstream recloser under maximum fault conditions or operating due to feeder energisation inrush.
In order to prevent malgrading with distribution transformer fuses, a 300ms definite time delay setting is preferred over an instantaneous setting.

Earth Fault pickup
The primary Earth Fault pickup should be set as follows:

- lower than the feeder Overcurrent pickup;
- as low as possible;
- to grade with downstream protection, but not with distribution transformer fuses, and not with fuses in general if it can be justified that time grading is still likely to exist between these devices for all practical fault situations; and
- typically, a maximum of 100 A at the zone substation.

The Earth Fault pickup should be set to ensure the following Operating Factors are observed:

Primary Protection Operating Factor
The Primary Earth Fault Operating Factors based on minimum network conditions should apply:

- for feeders without SEF protection – 2.0 (based on 20 ohm fault resistance); and

- for feeders with SEF protection – 2.0 (based on 0 Ohm fault resistance).

Backup Protection Operating Factor
The Backup Earth Fault Operating Factors based on normal network conditions should apply:

- for feeders without SEF protection - 1.5 (based on 20 ohm fault resistance as per normal Fault Level definition in section 4); and
- for feeders with SEF protection - 1.5 (based on 0 ohm fault resistance as per normal Fault Level definition in section 4);

Earth Fault Timing
The Earth Fault element timing should be set as follows:

- above all downstream devices for earth faults up to the maximum fault levels present at the downstream device location. Note that time grading should be achieved over distribution transformer fuses. However, time grading does not need to be achieved over larger fuses;

- below upstream devices, up to the maximum fault level that the feeder and upstream device shall simultaneously see for a feeder earth fault; and

- to protect any conductor within its Primary and Backup zone (where required) against thermal damage for fault levels that may be experienced by the conductor.

Earth Fault IDMT curves
Where possible, IEC 60255 SI, VI or EI curves are preferred. Other curves may be used where the downstream protection does not suit the use of the preferred curves.
High Set Earth Fault Elements
Where available, high set Earth Fault elements may be used, provided that the element is not capable of reaching to any downstream recloser under maximum fault conditions or operating due to feeder energisation inrush. In order to prevent malgrading with distribution transformer fuses, a 300ms definite time delay setting is preferred over an instantaneous setting.

2.3.1.3 Feeder Sensitive Earth Fault (SEF) Protection

Feeder SEF protection should be set as follows:

- SEF pickup: The SEF pickup shall be set between 4A and 10A primary. Current grading steps of 1A are recommended; and

- SEF time delay: The SEF time delay shall have a maximum of 10seconds delay and a minimum of 5 seconds. The recommended time grading margin is 1 second with a minimum of 0.5 seconds grading over downstream SEF relays.

***Note:** In general, Sensitive Earth Fault Protection should not be applied to a feeder to which an un-isolated single wire earth return (SWER) line is connected. SEF may be able to be applied to a feeder with un-isolated SWER following an assessment of the peak standing EF current caused by load and providing the SEF can be set with sufficient margin above this to prevent incorrect operation of the SEF element. If SEF is applied to a feeder with un-isolated SWER, the definite time delay must be no greater than 10 seconds.

2.3.1.4 Negative Phase Sequence (NPS) Protection

Where negative phase sequence protection is available with a protective device, NPS protection may be utilised to assist with phase to phase fault detection for both primary and backup protection. However, it is necessary that 3 phase overcurrent protection is still utilised as per clause 3.1.1 to ensure fault detection is provided for 3 phase fault conditions.

NPS pickup
The NPS should be set as follows:

- to be greater than 120% of the normal NPS standing current on the feeder due to phase load imbalance. Consideration should be given to increased normal NPS standing current due to load transfer from adjacent feeders, or temporary isolation of large single phase spurs; and
- to grade with downstream protection.

The NPS pickup should be set to ensure the following Operating Factors are observed:

Primary Protection Operating Factor
The NPS setting should provide a primary Operating Factor of **2.0** for phase-phase faults based on minimum network conditions.

Note: Consideration should be given to the effect of normal NPS standing current on the Operating Factor. In particular, if phase load imbalance is such that a phase to phase fault results in a reduced prospective NPS fault current due to the load imbalance, then the NPS pickup must be reduced to achieve the required Operating Factor, e.g. if minimum prospective NPS fault current = 200 amps, and maximum normal NPS standing current = 20 amps, a reduced minimum NPS fault current of 180 amps should be used. In this example a maximum NPS pickup of 90 amps should be used for Primary Operating Factor.

Backup Protection Operating Factor
The NPS setting should provide a Backup Operating Factor of **1.5** for phase-phase faults based on normal network conditions.
Note: Consideration should be given to the effect of normal NPS standing current on the Operating Factor. In particular, if phase load imbalance is such that a phase to phase fault results in a reduced prospective NPS fault current due to the load imbalance, then the NPS pickup must be reduced to achieve the required Operating Factor, e.g. if minimum prospective NPS fault current = 200 amps, and maximum normal NPS standing current = 20 amps, a reduced minimum NPS fault current of 180 amps should be used. In this example, a maximum NPS pickup of 120 amps should be used for Backup Operating Factor.

NPS timing
The relay NPS timing shall be set as such:

The equivalent overcurrent and earthfault curve for the NPS curve grade with the downstream and upstream protective devices, as follows:

- above all downstream devices for equivalent phase to phase and equivalent earth faults up to the maximum fault levels present at the downstream device location; and
- below upstream devices, up to the maximum fault level that the feeder and upstream device shall simultaneously see for a phase to phase fault.

The NPS equivalent overcurrent curve should coordinate with overcurrent curve to extend the protection reach for phase to phase faults. The NPS curve and overcurrent curve may have a crossover point for the protective device such that the NPS curve will detect the lower level faults, and the overcurrent curve will detect the higher-level faults.

NPS IDMT curves
Where possible, IEC 60255 “SI” or “VI” curves are preferred. Other curves may be used where the downstream protection does not suit the use of the preferred curves.

High Set Overcurrent Elements
Not normally required for NPS

2.3.1.5 Protection Groups

To enable the Live Line and Bushfire settings to be implemented, each recloser should be setup with the following protection groups: -

Group 1 (or A) - Normal settings with the addition of the live line settings

Group 2 (or B) - Spare for alternative settings, with the addition live line settings

Group 3 (or C) - Spare for alternative settings, used primarily for bypass of downstream recloser settings as per CEOP8071.

Group 4 (or D) - Total Fire Ban Settings.

Note, if alternative settings are not required, normal settings (Group 1 (A)), should be used in Group's 2 (B) and 3 (C) to ensure adequate protection, in the event of the wrong group accidentally being enabled.

2.3.1.6 Live Line Work Settings

The purpose of a Live Line Work Setting is to allow a special protection setting to be implemented when Essential Energy staff are undertaking live line work on the network. The intent of the Live Line Setting is to enable a very fast protection setting to be applied during Live Line work which will limit the risk to the live line workers by reducing the fault duration at the site in the event of a fault. To minimise the risk during live line work, Essential Energy will apply the following Live Line protection settings on the protective device (recloser or circuit breaker) immediately upstream of the live line work area.

1. The protective device must be set to one shot to lockout on overcurrent, earth fault, sensitive earth fault and NPS (if in use).
2. Where available and when it can be remotely selected by System Control, the protective device should be set to its Live Line Work Settings, with the following settings: -
    a. The overcurrent setting should be its normal overcurrent pickup with an inverse type curve (SI or VI) and an instant trip set at twice the device pickup. The Time multiplier should be 0.05 with zero time delay on the instant trip. For example, if the overcurrent setting of a recloser is 100A, Standard Inverse Curve, 0.2sec time multiplier and no instant trip, the Live Line setting would be 100A Standard Inverse with 0.05 time multiplier and a 200A instant trip with a zero time delay. In devices that do not allow an inverse type curve for its Live Line Work Settings and for relays contained within zone substations then an instant trip set at the device's normal overcurrent pickup, with zero time delay can be used.
    b. The Earth Fault settings should be a definite time curve at the normal earth fault pickup with a zero time delay. For example, if the normal Earth fault setting is 20A Standard Inverse Curve at 0.2 second time multiplier, the Live Line setting would be 20A definite time with a zero time delay.
    c. The SEF setting should have its time delay reduced to 1 sec. For example, if the normal SEF setting is 5A for 5sec, the Live Line Setting would be 5A for 1sec.
    d. If an NPS setting is in use on a device then the setting should be the normal NPS pickup with an inverse type curve (SI or VI) and an instant trip set at twice the device pickup. The Time multiplier should be 0.05 with zero time delay on the instant trip. For example, if the normal NPS setting is 20A Standard Inverse Curve at 0.3 second time multiplier, the Live Line setting would be 20A definite time with zero time delay. In devices that do not allow an inverse type curve for its Live Line Work Settings and for relays contained within zone substations an instant trip set at the device's normal NPS pickup, with zero time delay can be used

Note 1- it is acknowledged that protection discrimination/grading will likely not exist between the upstream device with Live Line Settings applied and the downstream protective devices during the work. This is accepted to reduce the risk to staff and the network from the live line work and on the understanding live line work would not occur during high fault risk times such as during storms.

Note 2- For SWER networks use the Overcurrent Live Line work settings above.

Note 3- Circuit Breakers/ Reclosers contained within Zone Substations supplying Distribution Feeders may not have the capability to enable use of a Live Line setting.

2.3.1.7 Bushfire Protection Settings (Total Fire Ban Settings)

Electricity assets are known to be a potential cause of bushfires in Australia, including bushfires which have caused fatalities as well as significant damage to property. Essential Energy's footprint, which is predominately located in rural areas, is especially prone to bushfire risk. The risk of electricity network assets causing fires and the impact of these fires is known to increase during hot, dry, and windy weather conditions. When these conditions occur, Total Fire Bans are declared for all or part of the network. The risk of ignition from faults on the network, can be reduced by shortening the fault clearance time and limiting reclose operations. However, it is also accepted that interrupting supply to area during high bushfire risk also creates additional risk though lack of supply for communications and firefighting equipment such as pumps. Essential Energy's Risk Management approach to Total Fire Bans is to supress the auto recloser function on specified devices as per CEOP2062. Specified devices would include:

- Field reclosers on rural feeder segments, including urban fringe. This can include devices inside zone substations protecting feeder segments in the affected area;
- Circuit Breakers/ Reclosers contained within Zone Substations supplying Distribution Feeders where the existing device/ protection relays have the capability to enable it;
- field reclosers with remote operation capability and communications connected to the Essential Energy SCADA control system. These can have their settings adjusted via operational scripts initiated from System Control Centre; and
- field reclosers associated with the specified declaration area only.

In addition, Essential Energy proposes to reduce the bushfire risk within its network in the future with the following protection philosophy:

DECLARED TOTAL FIRE BAN DAYS

During Total Fire Ban Day's, the reclosers in the designated area will be automatically switched to group 4 (D) settings and have auto reclose disabled. The proposed Group 4 (D) Overcurrent and Earth Fault protection settings should be set as fast as practical to enable the fault to be cleared in the minimum time while maintaining discrimination between reclosers. Grading margins can be reduced to 100ms between electronic devices to assist in speeding up protection operation. Discrimination between reclosers and fuses in the network may be compromised to allow faster clearance times, particularly in fire prone areas. The Sensitive Earth Fault settings would keep the same current values as the normal settings but have reduced time grading between devices. The last recloser on each line section will be set at 1 second with every upstream recloser set at 0.5 seconds higher progressing back along the feeder towards the zone substation.

Note: it is acknowledged that the move to a defined bushfire setting group will occur over time in conjunction with the recloser inspection cycle and that implementation of the bushfire settings may not occur until Group 4 (D) settings have been installed in all communications equipped electronic reclosers within a designated area. Initially, during Total Fire Ban Days, reclosers will have auto reclose disabled only.

2.3.1.8 Shunt Capacitor Protection

Fused capacitors - These banks usually consist of series and/or parallel combinations of individual capacitor cans per phase. Each unit is protected by its own fuse. Operation of a single fuse does not necessarily render the entire bank inoperative; however multiple failures can cause excess voltages to be impressed on the remaining cans.

2.3.2 Distribution Automatic Reclose

2.3.2.1 Automatic Reclose Justification

Because a large proportion of faults are of a transitory nature, it is normally an advantage to attempt to reconnect a distribution system that has been isolated by protection operation after a fault, if this is likely to restore supply to the distribution system without undue risk to personnel, livestock, or plant.

Sensitive Earth Fault protection

The type of fault covered by this type of protection is rarely, if ever transient in nature and often may be a danger to the general public.

Sensitive earth fault protection shall not be used to initiate an automatic reclose operation.

Distribution feeders

For the purpose of automatic reclose, distribution feeders can be categorised into overhead or underground types of feeders.

Overhead distribution feeders

An overhead distribution feeder is a feeder that is predominantly overhead in construction; it may have some small sections of underground construction.

Overhead distribution feeders can be further categorised into the following groups:

- **Urban overhead distribution feeders**

  Any overhead feeder that supplies predominantly urban areas, i.e. towns, villages etc

- **Rural overhead distribution feeders**

  Any overhead feeder that supplies predominantly rural areas, i.e. farms, hamlets etc

- **Industrial overhead distribution feeders**

  Any overhead feeder that supplies predominantly industrial areas, i.e. industrial parks etc. Generally, these feeders are short, with limited exposure, but are subject to high vehicle/ plant activity. For these reasons transient faults are not common and automatic reclose should, as a preference, not be implemented. Use of auto reclose may be considered on a case by case basis, where the network warrants it’s use. Where a feeder traverses a large section of rural area which may be subject to transient faults, automatic reclose may be considered.

Underground distribution feeders

An underground distribution feeder is a feeder that is predominantly underground in construction; it may have some small sections of overhead construction

Faults on underground feeders are usually not transient in nature; therefore, automatic reclose shall not be implemented on underground distribution feeders.

2.3.2.2 Automatic Reclose Attempts

The majority of transient faults will be cleared by a single tripping operation.

Automatic reclose shall be disabled prior to:

- live line work; and
- any manual close of a CB, including re-energising plant following maintenance and energising plant while sectionalising to locate a fault.

General statistics indicate a 70% successful reclose when slow reclosing is used, a further 5% on a second attempt and 1% on the third attempt. The possible success of reclosing against potential permanent damage to equipment needs to be considered when applying reclose. A maximum of two reclose attempts are recommended unless used in conjunction with sectionalisers.

Reclose dead time settings shall include allowance for:

- likely risk to personnel on or arriving at the scene;
- switch operating mechanism reset and stabilise time, including contact cooling times after passing fault current;
- relay reset time;
- likely effects on customer equipment of a restoration of supply after a short outage; and
- effects on equipment, including risk of damage from the mechanical and electrical effects of repeated fault current and trapped charges.

Urban overhead distribution feeders

Due to safety concerns involving automobile accidents with fallen conductors a maximum of one reclose attempt should be used on urban overhead distribution feeders, set at 10s.

Rural overhead distribution feeders

There should be two reclose attempts allowed on rural overhead distribution feeders. These will be 5s and 10s except where sectionalisers requiring additional recloses are installed. Where sectionalisers warrant the use of three reclose attempts, the dead times should be set to 5s, 5s and 10s respectively. The accumulated trip and reclose times should not be greater than 25s due to possible safety implications.

Field reclosers with fixed Automatic Reclose Attempts

The same principle detailed above should be applied to all field reclosers, however it is acknowledged that some recloser types installed on the network cannot alter either their number of reclose attempts or their dead times. These units are exempt from the requirements of 2.3.3.2, however if the units are replaced, they shall be upgraded to a device type that can comply.

HV Customers / Private lines

The customer must request in writing that auto reclose be enabled and state that they understand the following.

- What auto reclose means and its function.
- That they accept responsibility for the implications on their network of auto reclose.
- The dead time should be set at 10s.

2.3.2.3 Reclaim Time

Reclaim time must in all cases be longer than the operating time of any protection that may initiate an auto-reclose operation. (See 1 below).

Reclaim time settings must consider the mechanical limitations of the Recloser, CB and protection relays, which include but are not limited to:

- switch operating mechanism reset and stabilise time, such as spring charge time required to set up CB for a normal trip-close-trip sequence;
- thermal limits requiring cooling time between successive fault current incidents in equipment; and
- time for electromechanical relays to reset.

Generally, a reclaim time of 30s is sufficient, however refer to Attachment A for Total Fault Clearing Time calculations, methods and Terms.

1 This can be quite long for an Extremely Inverse IDMT overcurrent relay operating at about 150% of its nominal setting.

2.3.3 Automatic Field Reclosers

An automatic recloser is a self-contained device with the necessary circuit intelligence to sense overcurrents, to time and interrupt the overcurrents, and to reclose automatically to re-energize the line. If the fault should be "permanent" the recloser will "lock open" after the pre-set number of operations (usually one to three) and thus isolate the faulted section from the main part of the system.

Modern automatic reclosers enjoy the feature that they can employ different curves for each reclose attempt. If there are line section fuses downstream of the recloser it is beneficial to have at least one fast shot to provide some protection for the fuses for a transient fault.

Reclosers Classifications
Automatic circuit reclosers are classified on the basis of single or three phases, Hydraulic; Electronic or Microprocessor controls, Oil or vacuum interrupters.

2.3.3.1 O/C, E/F and SEF Protection online Reclosers

When selecting reclosers for field application, consideration should be given to ensure the unit is suitably rated for the interrupting capacity at the location being installed.

Overcurrent Protection covering phase and earth faults shall be set to detect faults on the line in the recloser's zone. The line recloser shall meet the same requirements as laid down in the distribution part of the guideline on Overcurrent and Earth Fault for grading and backup (including the setting of SEF protection).

2.3.3.2 Inrush Restraint

Used to temporarily prevent the recloser tripping on the initial close due to inrush currents. Before implementing inrush restraint, consideration should be given as to the need for its implementation and the setting required, which will be dependent on the load type and overcurrent and earth fault protection settings in the recloser. It is important to note that if turned on, inrush restraint may become active in times of very light load.

Typical settings for this function are 4 x full load current with a time setting of 0.15 second.

2.3.3.3 Cold Load Pickup

Used to temporarily prevent higher than normal load currents causing a trip due to loss of diversity when switching on to a system after an extended outage. Cold load pickup temporarily increases recloser protection pickup settings. **It is recommended to turn on cold load pickup only where necessary.**

How Cold Load pickup is applied can vary between recloser types, including when it becomes enabled. It is important to understand the particular implementation in the recloser being set by referring to the manufacturer's literature.

If cold load pickup is implemented, then backup and primary operating factors need to be maintained as per section 2.3.1.1 while cold load pickup is active.

Typical settings for this function are 1.5 - 2 x full load current and a time setting of 120 minutes

2.3.3.4 Recloser Delayed Operation

For reclosers where a delayed operation function is available (i.e 'Hit and Run') this function shall be enabled for operator-initiated closes. For all manual operations there is to be a 40 second delay before a close operation is initiated.

2.3.3.5 Coordination- Grading between ZS Relays, Reclosers and Recloser in Series

Recloser to recloser coordination is achieved by time-current grading primarily by the selection of different series trip-coil rating in hydraulic reclosers, or different minimum-trip current values in electronic reclosers and determination of the recloser time-current characteristics.

Grading margins starting from the source:

- Relay Disc type to hydraulic 400ms
- Relay Disc type to electronic 400ms
- Electronic to hydraulic 300ms
- Electronic to Electronic 300ms*
- Hydraulic to hydraulic 400ms
- Hydraulic to electronic 400ms.

Dead times should take into account slow reset times of hydraulic reclosers and margins between hydraulic devices should be increased with the number of reclose attempts.

Where fuse saving schemes are employed that use fast/slow curves upstream reclosing devices shall have sequence control enabled.

***Note:** 300ms is recommended, however this margin can reduce to 200ms if required. The reduction should be applied to the devices affecting the least number of customers.

2.3.3.6 Coordination between Recloser and Sectionaliser in Series

Installation of a sectionaliser does not affect the operating factor required at the recloser.

2.3.3.7 Coordination between Reclosers and Fuses in Series:

Coordination will depend on the number of shots set on the recloser for the downstream fuses.

In rural areas where transient faults may be a problem, reclosers may be set to give at least one fast trip, so if the fault is of a transient nature, it can be cleared without blowing the fuse and interrupting supply.

For optimum coordination between a recloser and fuse, their characteristics should be such that whilst all transient faults would be cleared by one or more fast recloser operations without the fuse blowing, permanent faults would blow the fuse before the recloser reached the lockout condition. This ideal is not always attainable for all faults values, yet a reasonable compromise can often be achieved by examination of recloser and fuse characteristics where ideally the fuse characteristic should fit between the instantaneous and the delay tripping for the recloser.

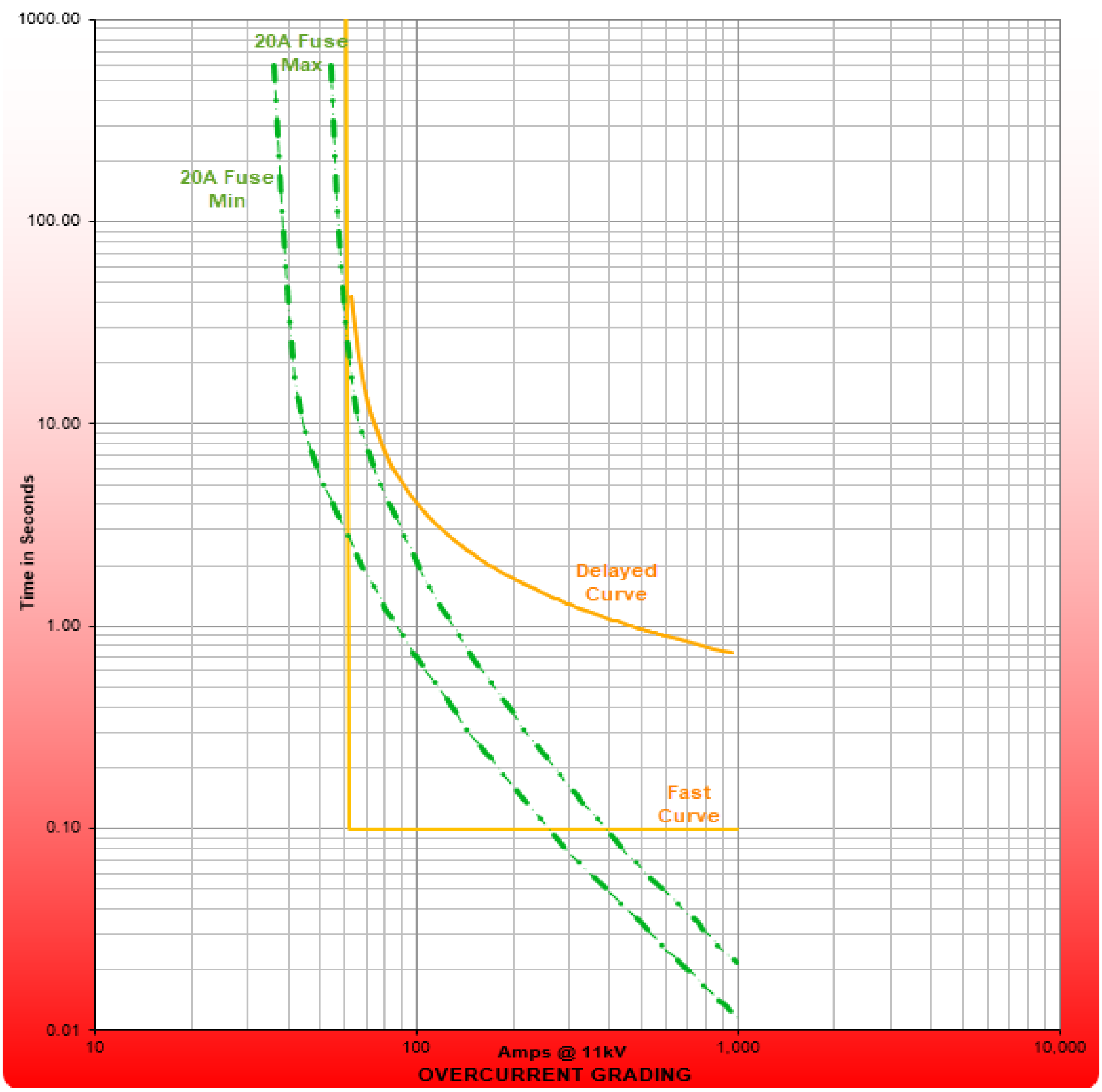
Where fast curves are employed on reclosers to protect fuses during transient faults, a minimum of 1.5 times operating factor should be used for fault detection.

For electronic reclosers the preferred fast trip is to use an Instantaneous setting. When using instantaneous trips a minimum time (usually 0.1 sec) should be used to prevent unnecessary spurious trips and provide protection stability e.g. from indirect lightning surges etc.

Backup protection is not required for high voltage fuses.

Where fuses are used to provide backup protection for a recloser a minimum operating factor of **3.0** times the fuse rating should be used for the backup fault coverage.

Consideration should be given to fuse element heating when coordinating with fuses, the grading margin will decrease for source side fuses with subsequent recloses, an increased grading margin and/or reclose times should be considered to ensure grading, the grading margin for load side fuses will be increased by successive recloses.



Coordination between Reclosers and Fuses

2.3.3.8 Coordination between Fuses and Downstream Reclosers

It is common on isolated SWER systems, rural zone substations and other rural networks for fuses to be the primary SWER isolation or zone substation transformer protection, with reclosers used to clear faults on the downstream distribution network respectively.

The source side fuses will normally be rated to provide protection to the transformer and will basically determine what the combination of recloser curves will be used, so that the fuse does not interrupt the circuit for any fault current on the recloser. The recloser's modified delayed curve must be faster than the fuse's minimum melt curve.

For the maximum available recloser fault current, the fuse minimum melting time must be greater than the average clearing time of the recloser delayed curve, multiplied by a specific factor which includes the impact of fuse heating (during the fault) and fuse cooling (during recloser deadtimes). The impact of this factor is usually expressed as an adjusted recloser delay curve which is coordinated with the fuse minimum-melting time curve. A tool to assist the calculation of this factor is included in the Essential Energy Grading Spreadsheet. This tool should be used to ensure correct coordination between the upstream fuse and downstream recloser.

In this scenario a fuse is being used to provide backup fault coverage for a Recloser.

A minimum operating factor of **3.0 times the fuse rating** should be used when selecting fuses for the primary protection zone. Where a fuse is required to provide backup fault coverage for a downstream device (such as a Recloser) a minimum operating factor of 3.0 times the fuse rating should also be used.

2.3.3.9 Basic Coordination Principles to be Observed

- The load-side device must clear permanent or temporary faults before the source side device interrupts the circuit (fuse link) or operates to lockout (recloser)
- Outages caused by permanent faults must be restricted to the smallest section of the distribution system.

These principles primarily influence the selection of curves and the sequences of operation of both source side and load side devices, and the general location of these devices on the distribution system.

2.3.3.10 Basic Guidelines for the Location of Reclosers

- Reclosers should be located to segment the system to minimise customer exposure to faults.
- Reclosers should be located to ensure fault coverage and to meet backup requirements.
- The principal fault causes in Essential Energy are storms, lightning, birds, branches and bark in roughly that order. Remote controlled electronic reclosers allow protection to be customised to these fault types to reduce fire risk and outage time.
- Excessive use of series reclosers can cause grading problems, and sectionalisers should be considered where applicable.
- Reclosers are the minimum requirement for new single customer spurs with load or generation above 1MVA as the connection point device.

2.3.4 Line Fuses

Fuses are the most basic protection devices available for overcurrent protection on a distribution system. Their primary function is to serve as inexpensive weak links in the circuit that open to clear (interrupt) overcurrent and protect equipment against overload and short circuit. They can also be used as line sectionalising.

Backup protection is not required for high voltage fuses. Where a fuse is required to provide backup fault coverage for a downstream device (such as a Recloser) refer to sect 2.3.3.8

All fuses operate in the same way. A conductor of limited cross-section is heated by current passing through it until it melts. This takes time, represented in time/current characteristics for the fuse. On melting, a break is caused in the element, at which an electrical arc is established. The arc burns in the fuse until the current returns to zero. Thus, there are two stages in fuse operation:

- The pre-arcing time (time/current characteristics)
- The arcing time.

The arcing behaviour is different for small, large and intermediate overcurrents.

The most common fuse type in use on the Essential Energy network are K type expulsive drop out (EDO) type. A minimum operating factor of **3.0 times the fuse rating** should be used when selecting fuses. Note that fuse continuous rating is typically above nominal rating. Always check the actual clearing time. For fuses other than K type refer to the manufacturer's literature for clearing characteristics

Fuse to Fuse Coordination

Discrimination: Fuse to fuse 100ms.

2.3.4.1 Principles of Operation of Fuses

Low overcurrents

At low overcurrents, the fuse breaks initially at just one point – the 'M' effect spot. This single arc needs to lengthen before the voltage developed across the fuse is large enough to allow extinction. It lengthens by burning away element's materials. The longer the time taken to do this, the more probable is the catastrophic failure.

High overcurrents

At high overcurrents fuse element vaporizes at all its constrictions. This produces a voltage drop sufficient to rapidly reduce the current to zero.

Current-time curves for both pre-arcing time and total operating time are published for higher overcurrents, but there is a large tolerance band for both, which gets wider (as a proportion of the total operation time) as the current increases. This is because both pre-arcing and arcing times depend heavily on the degree of DC offset current in the fault, which itself is determined by the point–on–wave of the voltage where the fault occurs (an unpredictable variable). For this reason, 'virtual time' curves are used at high currents, when operating times are less than about 0.1 sec.

The virtual time curves are not intended, therefore, to indicate actual operating times, but serve as a guide to grading fuses. The virtual total operating time of the minor fuse lie below the virtual pre-arcing time of the major fuse.

Intermediate overcurrents

The worst-case energy dissipation in fuses may occur at intermediate currents. The inductive energy dissipated by the arc, $0.5LI^2$, does not continuously increase with increasing prospective current, but peaks and then decreases.

The maximum Ldi/dt voltage developed across a fuse during operation is a function of the element length and design (number of construction) rather than circuit inductance. This voltage is limited by design and is fairly constant for any given fuse in a circuit up to its voltage rating. Above this voltage, the peak voltage may rise as the wider parts of the element disintegrate (due to persistent arcing caused by the higher circuit voltage) and from globules. The moral of this is: do not use a fuse in a circuit that exceeds its voltage rating.

2.3.4.2 Grading of Fuse to Fuse of the Same Voltage

The method of ensuring coordination is to inspect current-time curves, which generally include minimum pre-arcing time and maximum clearing time. Such curves are only available on distribution circuits. Time curves permit fuses of different manufacturers and designs to successfully coordinate. We simply need to ensure that the minimum pre-arcing time of the upstream fuse is greater than the maximum clearing time of the downstream fuse, up to the maximum fault current that can be seen by both. This maximum current condition is a fault just beyond the downstream fuse.

An acceptable rule for coordinating fuse links is that the maximum clearing time of the protecting fuse should not exceed 80% of the minimum melting time for the protected fuse. This assures that the protecting fuse will interrupt and clear the fault before the protected fuse is damaged in any way.

2.3.4.3 Types of Distribution Fuses

- Expulsion type fuses – These are the most commonly used fuse in distribution systems, the main duty of the fuse is to protect equipment against overcurrent of the system, secondary to indicate the fuse has been blown by dropping out of its in-service position.
- Powder filled fuses.
- Boric Acid fuses.

Reference should be made to the Distribution Transformer Fusing Policy CEOS5099 for the correct sized fuses.

2.4 Generators

All Generation proposed for installation on Essential Energy's Network shall be assessed on an individual case basis considering the type of Generator proposed and the proposed location on the network.

Reference should be made to the Generation Connection Protection guidelines CEOP8012 when checking/applying protection for these systems.

2.5 High Voltage Customers

The customer is to provide a protective system approved by Essential Energy to disconnect their equipment from the supply in the event of a fault on their equipment:

- all protection settings shall provide suitable discrimination with Essential Energy's system protection.
- protection pickup values should be set to 120% of agreed transfer capacity.
- all protective equipment must be maintained to an industry recognised standard.
- Essential Energy's is not required to provide backup protection to customer's equipment
- fuses can be used as the connection point for customers <1MVA. For customers => 1MVA, a recloser is to be used as the minimum connection point device to ensure that other Essential Energy customers are not affected by faults in the HV customer's network.
- if auto reclose is nominated for use refer to conditions in 2.3.3.2.
- minimum requirement would be OC, EF and SEF; and
- for UG networks use of an approved protection relay with a minimum of OC and EF. A self-powered type relay is acceptable.

3.0 AUTHORITIES AND RESPONSIBILITIES

Summarise responsibilities allocated to employees (by job/position title) within the process specified under Actions.

Position / Title	Responsibility
Head of Asset Management	• Shall have overall responsibility for the content, approval and maintenance of this Guideline.
Network Planning Manager and Regional Planning Managers	• shall be responsible for the implementation of this Guideline.
Zone Substation Maintenance Group / System Control / Regional Operations Managers	• shall be responsible for the operational aspects of implementation of these Guidelines on the distribution system.

Modifications to protection systems or settings are to be undertaken by authorised protection personnel or under direction of authorised protection personnel only. Disciplinary action will be taken against any employees found to be interfering with the protection systems without the appropriate authority.

4.0 DEFINITIONS

Backup protection
Protection system that provides protection coverage on the network to back-up a protective device that fails to operate or is out of service to the next downstream protective device.

EI
Extremely Inverse characteristic as defined in IEC 60255

Discrimination/ Grading
The coordination of non-unit protection by time

IDMT
Inverse Definite Minimum Time – A relay/ device operating characteristic that is inversely proportional to the measured quantity, eg, as the current increases, the operating time decreases. The definite minimum time varies between relay types, and typically occurs at 20 or 30 times the relay pickup.

Operating Factor- Safety Margin
Fault level divided by the protection pickup value**.**

Maximum Fault level
Fault level with maximum (lowest impedance) network configuration.

Minimum Fault level
Fault level with weakest (highest impedance) network configuration.

Normal Fault level
Fault level with normal network configuration.

NPS
Negative Phase Sequence – an overcurrent protection where the operating quantity is the I2 or Negative Phase Sequence current that is derived from the three phase quantities.

Operating Factor
The fault level divided by the pickup (setting value) with reference to an overcurrent, earth fault or NPS relay.

Overcurrent
An overcurrent protection where the operating quantity is derived from any of the three phase quantities.

Primary distribution feeder
a distribution line connecting a sub-transmission asset to either other distribution lines that are not sub-transmission lines, or to distribution assets that are not sub-transmission assets. (from NER)

PSA
Protection Setting Advice

Primary protection
Protection system that provides protection coverage on the network to the next downstream protective device.

SCADA
Supervisory Control and Data Acquisition.

SI
Standard Inverse characteristic as defined in IEC 60255

Sub-transmission
any part of the power system which operates to deliver electricity from the transmission system to the distribution network and which may form part of the distribution network, including zone substations.

Sub-transmission line
a power line connecting a sub-transmission asset to either the transmission system or another sub-transmission asset. (from NER)

SWER
Single wire earth return.

NPS
Negative phase sequence.

SEF
Sensitive earth fault.

VI
Very Inverse characteristic as defined in IEC 60255

Zone Substation
A substation for the purpose of connecting a distribution network to a sub-transmission network (from NER).

5.0 REFERENCES

Internal	
CEOP8002.01 – Branch Procedure: Transmission and Sub-transmission Protection Guidelines	*Policy Library*
Company Procedure (Governance) - Information Security Sensitivity Labelling and Handling - CEOP1096	*Policy Library*
Branch Procedure (Network) - Subtransmission Protection Guidelines – CEOP8002.01	*Policy Library*
Annexure A - Total Fault Clearing Time Calculations, Methods and Terms.	*Policy Library*
CEOP8012 Generation Connection: Protection Guidelines.	*Policy Library*
CEOF6186 – Subtransmission: Protection Design Request	*Policy Library*
CEOS5099 – Distribution: Transformer Fusing	*Policy Library*

External
ENA C(b)1-2006 : Guidelines for design and maintenance of overhead distribution and transmission lines.
"Guide to the Application of Autoreclosing to Radial Overhead Lines Supplying Urban and Rural Areas", D (b) 12 1991, Electricity Supply Association of Australia.
IEC 61000 Electromagnetic Compatibility.
IEC 60255 Electrical Relays
Appropriate Australian Standards, including AS/NZS 3000 (SAA Wiring Rules);
National Electricity Rules.

6.0 RECORDKEEPING

The Essential Energy employees associated with protection shall be responsible for the recording, storage and maintenance of all protection records. Details of all the current and historic settings, tripping schemes, instrument transformer ratios, reclose times, configurations, software files, firmware and software versions, calculations and analysis details etc of all transmission, sub-transmission and distribution protection equipment and devices, should be stored. All Essential Energy employees associated with planning, protection, control and maintenance should have read access to PSAs

7.0 REVISIONS

Issue No.	Section	Details of changes in this revision	Change Risk Impact?
1	All	CEOP8002 split into two Documents - CEOP8002.01 Subtransmission Protection Guidelines - CEOP8002.02 Distribution Protection Guidelines	

Annexure A - Total Fault Clearing Time Calculations, Methods and Terms

Figure 1 and **Figure 2** show the method of calculation of Total Clearing Time and clarify some of the terms used.

Figure 1: Permanent Fault Trip Sequence with One Reclose

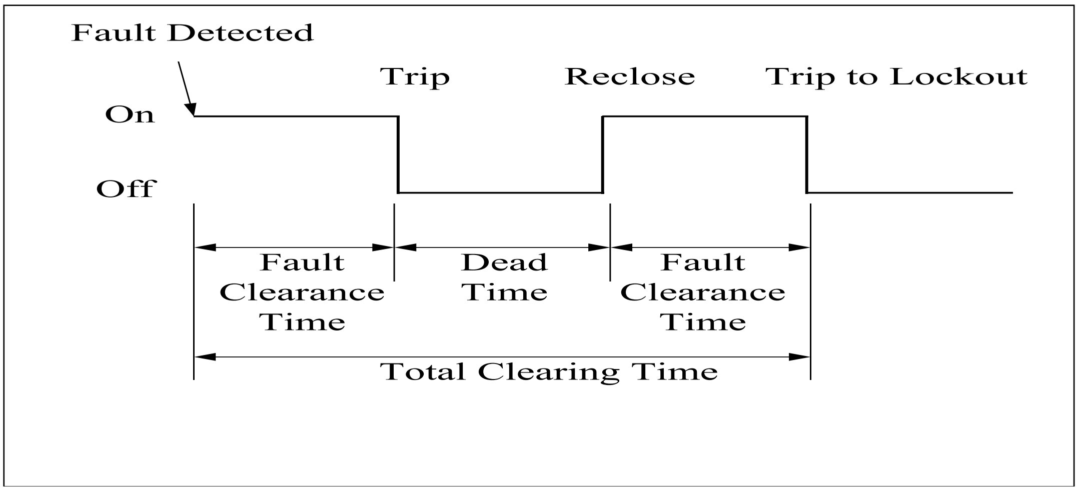


Figure 2 Permanent Fault Sequence with Three Recloses when used in conjunction with a sectionaliser