Standard

Protection of Transmission Lines Standard

R246427

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Authorisations

Action	Name and title	Date
Prepared by	Anthony Januba, Senior Asset Strategy Engineer	30/06/2022
Reviewed by	Satendra Bhola, Principal Asset Engineer	30/06/2022
Authorised by	Michael Emmett, Acting Team Leader Substations Asset Strategy	8/11/2022
Review cycle	30 months	

Responsibilities

This document is the responsibility of the Substations Asset Strategy Team, Tasmanian Networks Pty Ltd, ABN 24 167 357 299 (hereafter referred to as "TasNetworks").

Please contact the Substations Asset Strategy Team Leader with any queries or suggestions.

- Implementation All TasNetworks staff and contractors.
- Compliance All group managers.

Minimum Requirements

The requirements set out in TasNetworks' documents are minimum requirements that must be complied with by all TasNetworks team members, contractors, and other consultants.

The end user is expected to implement any practices which may not be stated but which can be reasonably regarded as good practices relevant to the objective of this document.

Record of revisions

Section number	Details
1.7.1	Added two standards to the reference list
3.1.2	Modified the relay requirements for IEC 61850
4.3 (b)	Added requirement for double point indication
Appendix 1	Removed any reference to specific relay models

Table of contents

1 General

1.1 Purpose

The purpose of this document is to define the requirements, and to describe the application philosophy, for protection and control of transmission line ends in the Tasmanian Interconnected Power System under the responsibility of Tasmanian Networks Pty Ltd (hereafter referred to as "TasNetworks").

1.2 Scope

This document applies to the protection and control facilities on interconnected transmission line ends consisting of part of a two, three or four ended transmission line under the responsibility of TasNetworks and associated with busbars consisting of either of the following busbar configurations:

(a) Single busbar.

(b) Double or triple busbar.

(c) Double breaker in the diameter between two main busbars.

(d) Circuit breaker and a half in the diameter between two main busbars.

(e) Ring busbar.

(f) H-type busbar.

This standard contains requirements for design and is to be applied on new installations as well as redevelopment of part or all existing installations where the busbar arrangement may consist of a combination of the above mentioned configurations.

1.3 Objective

TasNetworks requires design as covered in this standard to ensure:

(a) personnel and public safety;

(b) safety of TasNetworks' assets;

(c) reliability and continuity of power supply to the power transmission network;

(d) that relevant Australian legal requirements are met;

(e) that the requirements of the National Electricity Rules (NER) are met;

(f) ease in operation and maintenance;

(g) minimum disruption to the EHV supply system following a fault;

(h) that the requirements of TasNetworks' business plan are met; and

(i) that the exposure of TasNetworks' business to risk is minimised.

1.4 Precedence

Any apparent conflict between the requirements of this standard and the law, mandatory requirements, industry standards, project specifications, non-statutory standards or guidelines, and any other associated

documents should be brought to the immediate attention of TasNetworks for resolution and no action must be taken that might result in a breach of law or mandatory standard.

Where there may be a conflict between the requirements of this standard and any:

(a) law, mandatory requirement or industry standard, then that law or statutory requirements will prevail over this standard;

(b) non-mandatory standard, or guideline, then this standard will prevail over that standard or guideline; and

(c) project specification, then a deviation must be specifically requested and approved in writing by TasNetworks' Substations Asset Strategy Team Leader.

Approval for a deviation to this standard may only be accorded if it does not reduce the quality of workmanship, pose a safety risk to personal or equipment and does not deviate from the intent of this standard.

1.5 Abbreviations

AR	Auto Reclose
CBF	Circuit Breaker Failure
CT	Current Transformer
CTS	Current Transformer Supervision
EHV	Extra High Voltage (≥ 66 kV)
HMI	Human Machine Interface
I/O	Input and Output
LAN	Local Area Network
MCB	Miniature Circuit Breaker
NER	National Electricity Rules
NOCS	Network Operational Control System
OHEW	Overhead Earth Wire
OPGW	Optical Ground Wire
POTT	Permissive Over-reach Transfer Trip
PSB	Power Swing Blocking
PUTT	Permissive Under-reach Transfer Trip
SCADA	Supervisory Control And Data Acquisition
SOE	Sequence of Events
SOTF	Switch On To Fault
SPAR	Single Pole Auto Reclose
TPAR	Three Pole Auto Reclose
V	Volts
VT	Voltage Transformer
VTS	Voltage Transformer Supervision

1.6 Symbols

K_0	Zero Sequence Compensation Factor
R_1	Positive Sequence Resistance
R_2	Negative Sequence Resistance
R_0	Zero Sequence Resistance
R_{mo}	Zero Sequence Mutual Resistance
X_1	Positive Sequence Reactance
X_2	Negative Sequence Reactance
X_0	Zero Sequence Reactance
X_{mo}	Zero Sequence Mutual Reactance
Z_1	Positive Sequence Impedance
Z_2	Negative Sequence Impedance
Z_0	Zero Sequence Impedance
Z_{mo}	Zero Sequence Mutual Impedance

1.7 References

As a component of the complete specification for a system, this standard is to be read in conjunction with other standards and documents as applicable. In particular, this includes the project specifications and the below mentioned literature.

1.7.1 Reference Documents

SCADA Systems Standard (R246439)

IEC 61850 Protection and Automation Standard (R1606300)

Testing, Commissioning and Training Standard (R246497)

Secondary Equipment Testing Standard (R244782)

Secondary Systems – General Requirements Standard (R246444)

Secondary Cable and Wiring Standard (R1744962)

Protection of EHV Busbars Standard (R246414)

Technology Asset and Change Management Standard (R1400111)

Security Event Logging and Monitoring Standards (R1313426)

1.7.2 TasNetworks drawings

All project specific application design drawings shall be prepared using the appropriate TasNetworks standard protection scheme design template. This suite of standard design drawings for the 110 kV and 220 kV transmission line protection scheme will be issued together with the project specification for each project which should be customised by the designer for specific site application.

New standard panel design drawings shall only be developed with prior approval from TasNetworks' Substations Asset Strategy Team Leader.

2 Philosophy

2.1 Design Philosophy

The protection and control scheme of the transmission line shall be designed to ensure that:

(a) faults on any part of the transmission line are detected by at least two high speed independent protection relays that have the capability of independently initiating fault clearance within the required time detailed in the NER;

(b) the protection scheme applied is adaptable and adequate for protection of the entire transmission line and provide backup protection for associated transmission line circuit end equipment and adjacent transmission lines if required;

(c) the protection scheme is arranged to ensure no part of the primary system is unprotected;

(d) the protection scheme is capable of independently tripping the circuit breaker(s) selectively so as to clear the fault within specified fault clearance times as stated in schedule S5.1a.8 and table S5.1a.2 of the NER;

(e) three terminal lines are protected by current differential protection, especially when the application of blocked distance protection is difficult to implement due to relative lengths of line sections;

(f) the protection for the 220 kV transmission lines shall be phase segregated and shall be capable of single pole tripping. For 110 kV transmission lines, only three pole tripping shall be provided; and

(g) the protection and control scheme shall consist of two independent protection relays designated the 199A protection relay and the 199B protection relay and a separate bay control relay designated 199C. The protection relays must be from different manufacturers or models to achieve redundancy and diversity.

(h) At sites where IEC 61850 process and/or station bus is implemented, all design requirements shall be in accordance with the TasNetworks IEC 61850 Protection and Automation Standard.

3 Functional requirements

3.1 Protection functional requirements

The following functionality shall be available in each protection relay:

(a) Current differential protection with line charging compensation.

(b) Inbuilt distance protection capable of being independently switched into service automatically upon failure of the current differential communications.

(c) High impedance earth fault protection capable of detecting earth faults having a resistance of up to 300 ohms. Use of directional feature may be required to achieve selectivity.

(d) Broken conductor protection.

(e) Permissive and direct inter-trip function.

(f) Three phase directional and non-directional overcurrent and earth fault protection.

(g) Circuit Breaker Failure (CBF) protection consisting of overcurrent check functions together with timers adjustable from zero to 300 milliseconds.

(h) Inbuilt stub protection when applied to breaker and a half and double breaker configurations.

(i) Three phase under voltage and over voltage protection.

(j) Under and over frequency protection including rate of change of frequency element.

3.1.1 Distance protection requirements

The following functionality shall be provided in each protection relay:

(a) Minimum of four impedance measuring zones with time and distance step characteristics of mho, quadrilateral or other similar geometric shape.

(b) Each Zone settable independently without limitation and shall be capable of being programmed for forward and reverse reach. In addition, each Zone shall be independently capable of being switched 'in service' and 'out of service'.

(c) Zone characteristics adjustable to account for load encroachment.

(d) Zone 1 operating time not to exceed 30 milliseconds for faults up to 80% of the line impedance with System Impedance Ratios (SIR) up to 50.

(e) Logic to allow for the following scheme options:

  (i) Basic step distance (no permissive inter-trip signalling).

  (ii) Permissive under-reach transfer trip (PUTT).

  (iii) Permissive over-reach transfer trip (POTT).

  (iv) Permissive over-reach with weak in feed (Echo and transfer trip).

  (v) Blocking to operate in conjunction with a reverse reach element.

(f) Residual compensation for settable transmission line zero sequence to positive sequence impedance ratios.

(g) Facilities shall be provided to apply zero sequence mutual compensation quantities from a parallel transmission line where both transmission lines share common buses at the line ends, this function is to be enabled only if required in the project specification, otherwise it is to be disabled.

(h) Relay settings available to cater for transmission line impedance angles from 30 degrees to 90 degrees.

(i) Switch on to fault (SOTF) protection.

(j) Power swing blocking (PSB).

3.1.2 General relay requirements

(a) For double breaker or circuit breaker and a half arrangements, the relays must be capable of accepting multiple current inputs to ensure that biased stabilisation can be achieved.

(b) Multiple selectable setting groups with a minimum of three setting groups.

(c) Fault location indication. The fault location shall be possible regardless of the availability of the back-up distance protection and/or its individual zones.

(d) Phase segregated measurement and phase identification for the faulted phase.

(e) Stabilisation to prevent operation due to noise in the CT output signal.

(f) Sensitive only to the fundamental component of fault current.

(g) Insensitive to charging current of the transmission line or transformer inrush current.

(h) Dynamic stabilisation against CT saturation.

(i) Necessary outputs for initiation and blocking of auto reclose cycle.

(j) Necessary input to enable or disable single pole tripping depending on the status of the auto reclose function.

(k) Capability to detect an evolving fault during the dead time of a SPAR and initiating three pole tripping of the circuit breaker and blocking the operation of the auto reclose cycle.

(l) Necessary I/O to be energised from various protection schemes as required or for building up logic externally. A 10% spare capacity over the requirements of the engineered solution shall be provided.

(m) Local and Remote indication of three phase and line currents and voltages. The unit shall have a freely configurable CT and VT ratio to represent the primary values in the circuit.

(n) Operate from 1 Amp CT secondary connections, with a separate input for the neutral. If 5 Amp relays are required, it shall be stated in the project specification. 1 Amp rated relays shall be capable of withstanding 2 Amps continuously and 5 Amp rated relays shall be capable of withstanding 10 Amps continuously.

(o) The relays shall be connectable for 110 V and 110/$\sqrt{3}$ V, VT secondary connections.

(p) VT fuse-failure and supervision with separate monitoring of individual phases. The fuse-failure function shall block the operation of any voltage operated protection elements.

(q) Supervision of CT secondary, the output of which may be used to block the protection and to provide an alarm.

(r) Inbuilt SOE and oscillographic disturbance recorder with time and date tagged events recorded and displayed local and remote.

(s) Capable of communicating all parameters including the protection settings and recorded SOE to the substation SCADA system and be capable of being configured remotely via the substation SCADA system or separate communications interface.

(t) A local HMI to read on-line parameters of primary data, recorded parameters, setting parameters and self-diagnosis details.

(u) Trip circuit supervision to monitor the associated trip circuit and circuit breaker trip coil.

(v) The protection relays must also be capable of performing all auto reclose functions as described in the following sections of this standard.

(w) Ideally the relays would have the ability to provide synchrophasor data. However, if synchrophasor functionality is required, it will be specified in the project documentation.

(x) Be capable of communications protocol DNP3 as a minimum. Where communication protocol IEC 61850 GOOSE and MMS functionality is required, it will be specified in the project documentation.

(y) Be capable of communicating on the SCADA network via Ethernet RJ45 or fibre connection;

(z) Capable of time synchronisation via PTP (preferred option) or IRIG B; and

(aa) At sites where IEC 61850 process and/or station bus is implemented, all design requirements shall be in accordance with the TasNetworks IEC 61850 Protection and Automation Standard.

3.2 Control functional requirements

The following functionality shall be provided by the bay control relay:

(a) Single shot SPAR or TPAR with freely configurable reclaim and dead time. Auto reclose must be capable of being locally and remotely switched in and out with accompanying indications.

(b) Control of circuit breaker and motorised disconnector.

(c) Operational metering of transmission line quantities.

(d) For double breaker or circuit breaker and a half arrangements, the bay control relay must be capable of accepting multiple current inputs to ensure that metering quantities can be summed for the transmission line.

(e) Monitoring the status of the circuit breaker and to provide logic to make the necessary decision to enable or disable the auto reclose function.

(f) Monitoring the status of the bay and other relevant disconnectors and to provide logic for the interlocking scheme and for voltage selection for metering and protection applications.

(g) The ability to be connected to the station SCADA system for alarms and monitoring of the associated transmission line bay.

(h) Synchronism checks before auto reclose following a three pole trip. The synchronising check unit shall check for magnitude difference of voltage and frequency and phase angle difference of voltage prior to allowing closure of the circuit breaker.

(i) Synchronising check on circuit breaker close command for energisation for dead line – dead bus, live line – live bus, dead bus – live line or live bus – dead line conditions.

(j) Remote system synchronising on circuit breaker close command employing a 5 minute window during which circuit breaker closure can occur under synchronised conditions.

(k) Blocking facility for VT MCB trip and/or fuse failure condition on the associated protection, loss of communications for the associated protection and for 'live line'; the latter function shall be selectable – a blocking signal shall terminate the auto-reclose sequence even if the blocking signal occurs after the auto reclose sequence has been initiated.

(l) For double breaker and one and a half circuit breaker installations the bay control relay must be capable of trip circuit supervision. Trip circuit supervision must monitor each circuit breaker trip coil and associated circuit regardless of the circuit breaker being open or closed.

(m) The relay must be capable of internal supervision and self- diagnosis features.

4 Protection and control application

The following arrangements shall be applied to the application of the main protection relays:

(a) The protection relays are connected to two independent cores of the transmission line CT secondaries.

(b) The protection relays use independent VT secondary circuits for voltage input and this input is routed via MCBs.

(c) The protection relays use separate DC supplies are derived from the 'A' and 'B' DC supply systems.

(d) Circuit breaker tripping is initiated via hard wiring direct to the 'A' and 'B' trip coils respectively.

(e) At sites where IEC 61850 process and/or station bus is implemented, all design requirements shall be in accordance with the TasNetworks IEC 61850 Protection and Automation Standard.

(f) The following software controls and monitering are to be implemented:

  (i) Change the device default password;

  (ii) Disable or remove unused interfaces; and

  (iii) Disable built-in or default user accounts.

  (iv) If possible, record:

    a. What activity was performed (e.g. setting changes on protection relay);

    b. Who performed the activity (e.g. engineer or operator); and

c. When the activity was performed (e.g. time and date).

4.1 Current differential protection application

Where sufficient communications circuits are available, biased current differential protection is preferred and shall be applied as the main protection element. For application of current differential protection on three ended transmission lines, the preferred arrangement is to have three separate communications circuits linking each line end. The relay must be set to ensure that current differential protection is still available with the loss of one communications circuit. Where three separate communications circuits are not available, one line end protection relay shall be used to transfer both remote end measurements to the other two line ends.

4.2 Distance protection application

The distance protection shall be disabled when all of the following conditions are present:

(a) Duplicate independent high speed differential protection schemes exist for transmission line protection.

(b) Duplicate busbar or transformer protection exists at the remote end station that is under the control of TasNetworks.

(c) Dead Zones do not exist on transmission lines and/or on remote end station busbars.

(d) Two separate, diverse communications circuits are available for current differential protection or direct inter-trip.

Where the above mentioned conditions are not met, distance protection shall be applied in the following manner:

(e) Zone 1 of the distance protection shall be disabled and will be enabled only when the current differential protection is out of service.

(f) The Zone 2 and Zone 3 of the distance protection shall be enabled, (concurrently with the current differential protection), to provide back-up protection to the transmission line and the remote line end substation busbar. In this condition, when both current differential protection and distance protection are active, the high impedance earth fault protection shall remain in service.

(g) Where the distance protection is used as back-up to the current differential protection, permissive signalling, e.g. PUTT, shall not be applied unless specifically required for particular applications and with the prior approval of TasNetworks.

Where current differential protection cannot be enabled due to non-compatible protection relays at the remote end or a lack of adequate communication facilities e.g. no optical fibre or microwave, but where signalling is possible e.g. via power line carrier, duplicate distance protection schemes shall be applied as the main protection in the following manner:

(h) Zone 1 shall be enabled.

(i) If SPAR is required, PUTT signalling shall be applied to the distance protection scheme.

(j) If TPAR is required, PUTT signalling shall be applied to the distance protection scheme only if high speed clearance is required for the entire length of the transmission line.

(k) Where a signalling scheme is required for multiple ended transmission lines, a blocking scheme initiated by reverse looking zones, can be applied based on protection coordination studies.

4.3 Stub protection application

For circuit breaker and a half or a double breaker configuration where a line circuit breaker in addition to the diameter circuit breakers and an associated line CT are not provided, 'stub' protection is required to cater for busbar faults on the diameter when the transmission line is out of service. The following points relate to the 'stub' protection:

(a) The relay shall have inbuilt 'stub' protection to cater for bus faults when the protection is applied to a transmission line connected to a circuit breaker and a half configuration or a double breaker configuration.

(b) The 'stub' protection shall be switched into service by the auxiliary contacts of a transmission line disconnector, utilising double point indication to indicate when the transmission line is out of service.

(c) The 'stub' protection shall be limited to the area bound by the CTs and shall not have an impact on the remote line end.

(d) The 'stub' protection relay shall remain stable for heavy through fault currents on the diameter to which it is connected; this may require the application of duplicate three phase current input relays.

(e) The operation of the distance protection and the current differential protection shall be blocked when the protection is in the 'stub' protection mode.

(f) The auto reclose function in the associated bay control relay shall be blocked when the protection is in the 'stub' mode.

4.4 Fault locator application

(a) The fault locator shall only transmit a fault location following a trip via the protection relay.

(b) The output reading of the fault locator shall be communicated via SCADA to the Network Control Centre in kilometre units.

4.5 SOE and disturbance recorder application

(a) All functions capable of initiating trips and auto reclose shall be mapped to the internal event and disturbance recorder.

(b) All analogue inputs and calculated residual quantities shall be mapped to the internal disturbance recorder, including measured frequency.

(c) Oscillographic fault recorder should be set to capture 50% of prefault data.

(d) The output of the SOE and disturbance recorder devices shall be available for secure remote interrogation via an engineering LAN.

(e) The retrieval system shall be in accordance with TasNetworks' SCADA System Standard.

4.6 Bay control, indication and metering application

(a) The bay control relay shall derive current from the transmission line metering CT for metering purposes.

(b) The bay control relay shall derive the metering voltage supply from the number 2 secondary winding of the transmission line VT.

(c) The synchronising check function shall derive the busbar voltage via the voltage selector function of the bay control relay.

(d) The circuit breaker control functions for manual and remote operations shall be derived from the 'A' DC supply.

(e) Local and remote open commands shall be connected to the associated circuit breaker trip coil 'A' only.

(f) The SPAR function shall be selected for 220 kV interconnected transmission lines and TPAR for 110 kV transmission lines.

5 Protection and control settings

5.1 General information

The setting requirements mentioned in this document are not the full requirement for settings but represent the basic setting requirements for the protection. The contractor shall supply a setting calculation report and design settings via TasNetworks' Stationware database.

Configuration of IEC 61850 process and/or station bus shall be in accordance with TasNetworks' IEC 61850 Protection and Automation Standard.

The following general information shall be supplied with the transmission line protection settings:

(a) Name of station at which the protection scheme is located.

(b) Name of the transmission line.

(c) Length of the transmission line (km) - in the case of lines having greater than 2 line ends, the length of each section shall be provided.

(d) Voltage of transmission line (kV).

(e) Positive sequence impedance of transmission line (Z1) (ohms) in rectangular form $R_1 + jX_1$.

(f) Zero sequence impedance of transmission line (Z0) (ohms) in rectangular form $R_0 + jX_0$.

(g) Zero sequence mutual impedance of transmission line (ohms/km) in rectangular form where applicable for parallel transmission lines $Rm_0 + jXm_0$.

(h) Charging current of transmission line (Amps).

(i) Maximum load current of transmission line (Amps).

(j) Maximum and minimum fault currents at each line end for a three phase fault and a phase to earth fault (Amps).

(k) Minimum phase to earth fault current for a fault resistance of 300 ohms (Amps).

(l) CT ratio.

(m) VT ratio.

(n) Setting calculations.

5.2 Current differential protection settings

Settings for current differential protection using a biased characteristic:

(a) Differential current threshold setting.

(b) Bias current setting.

(c) Characteristic slope angle – first setting.

(d) Characteristic slope angle – second setting.

Settings for current differential protection using an alpha plane characteristic:

(e) Phase current differential setting.

(f) Earth fault current differential setting.

(g) Negative sequence current differential setting.

(h) Angle of restraint region.

(i) Radius of restraint region.

Note: In the event that starting and guard relays are applied, such relays shall not be energised for transmission line emergency operating conditions.

5.3 Distance protection settings

5.3.1 Distance protection settings for two ended transmission lines

The following describes the settings to be applied to the back-up distance protection for two terminal transmission lines. The settings shall be setting group 1 settings unless otherwise noted.

(a) Zone 1 Settings

  (i) Zone 1 reach setting of the protection shall be set to reach between 60% to 80% of the transmission line apparent positive sequence impedance (Z1), incorporating the effects of zero sequence mutual coupling.

  (ii) Zone 1 line angle shall be set to tan-1 (X1/R1).

  (iii) The Zone 1 operating time setting shall be instantaneous.

  (iv) The Zone 1 earth fault elements resistive axis reach setting shall be set to maximum resistance consistent with the constraints of PSB settings and maximum load current in the transmission line.

  (v) Where zero sequence mutual impedance associated with an 'out of service and earthed' transmission line impacts on the Zone 1 reach for phase to earth faults, the setting may need to be reduced to comply with the maximum reach requirement of 80% of transmission line apparent Z1.

(b) Zone 2 Settings

  (i) Zone 2 reach setting of the protection shall be set to reach 120% of the transmission line apparent positive sequence impedance but not greater than 50% of the shortest transmission line apparent positive sequence impedance connected to the remote end busbar.

  (ii) Zone 2 line angle shall be set to tan-1 (X1/R1).

  (iii) The Zone 2 operating time shall be 400 milliseconds unless protection coordination studies demonstrate a mis-coordination with downstream protection. Where a time delay of 400 milliseconds cannot be achieved, TasNetworks must be notified. Additionally, where a radial transmission line is terminated directly to a transformer, and backup fault clearance times exceed the critical clearance time found through power system studies, the zone 2 time delay may be reduced to ensure compliance with the NER.

  (iv) Where Zone 2 element has a separate zero sequence compensation factor setting, the setting shall be calculated in the same manner as for Zone 1 using the appropriate Z1 and Z0.

  (v) Where a phase to earth fault quadrilateral characteristic is applied, the Zone 2 earth fault elements resistive axis reach setting shall be set to the associated value for Zone 1. The Zone 2

element shall detect a phase to earth fault having a resistance of not less than 10 ohms located on or near the remote station busbar with all fault current in feeds considered.

(vi) Where zero sequence mutual impedance associated with an 'in-service' parallel transmission line impacts on the Zone 2 reach for phase to earth faults, the Zone 2 reach may need to be increased by increasing the zero sequence compensation factor.

(vii) Where zero sequence mutual impedance associated with an 'out-of-service and earthed' transmission line impacts on the Zone 2 reach for phase to earth faults, the setting may need to be reduced to comply with the reach constraint of not exceeding 50% of the shortest adjacent transmission line apparent impedance.

(viii) Load current and PSB settings may constrain the desired setting of Zone 2. Therefore Zone 2 setting shall take into account these constraints.

(c) Zone 3 Settings

(i) Zone 3 element shall be set to cover 150% of the protected transmission line apparent positive sequence impedance. In addition, the setting must allow for maximum possible load current to flow without tripping operation.

(ii) Zone 3 line angle shall be set to tan-1 (X1/R1).

(iii) The Zone 3 operating time shall be 1.0 second.

(iv) Where Zone 3 element has a separate zero sequence compensation factor setting, the setting shall be calculated in the same manner as for Zone 1 using the appropriate Z1 and Z0.

(v) Where a phase to earth fault quadrilateral characteristic is applied, the Zone 3 earth fault elements resistive axis reach setting shall be set to the associated value for Zone 1.

(d) Load Encroachment element settings

The setting of impedance value for the load encroachment element shall be set according to equation:

$Z = (0.9 \times KV^2)/(1.1\ MVA)$ where kV is the nominal system voltage and MVA is the maximum rating of line equipment. The setting of angle should be based on worst line loading power factor +5 degrees safety margin.

5.3.2 Distance protection settings for multi ended transmission lines

The following describes the settings to be applied to the back-up distance protection for multi terminal transmission lines. The settings shall be setting group 1 settings unless otherwise noted.

(a) Zone 1 settings

(i) Where the geometry of the multi terminal transmission line configuration permits, Zone 1 reach shall be set btween 60% to 80% of the apparent positive sequence impedance of the shortest transmission line end as seen by the relay with the largest infeed removed.

(ii) Zone 1 reach for each end should overlap each other. If the transmission line configuration prevents this, then at least one protection scheme shall detect a fault at the tee points in Zone 1 reach. In this case, the overlap of all Zone 1 characteristics is not possible and Zone 2 operating time is not acceptable then either PUTT or POTT scheme shall be applied to clear transmission line faults.

(iii) Zone 1 line angle shall be set to tan-1 (X1/R1).

(iv) The Zone 1 operating time setting shall be instantaneous.

(v) The Zone 1 earth fault elements resistive axis reach setting shall be set to maximum impedance consistent with the constraints of PSB settings and maximum load current in the transmission line.

(vi) Where zero sequence mutual impedance associated with an 'out-of-service and earthed' transmission line impacts on the Zone 1 reach for phase to earth faults, the setting may need to be reduced to comply with the maximum reach requirement of 80% of transmission line Z1. This setting, accommodating the requirements for when a parallel line is 'out of service and earthed', shall be in setting group 2.

(b) Zone 2 settings

(i) Zone 2 reach setting of the protection shall be set to reach 120% of the longest transmission line apparent positive sequence impedance but not greater than 50% of the shortest transmission line apparent positive sequence impendence connected to the remote busbar. The Zone 2 reach setting shall take into account fault current in-feed from the other terminals and the consequent attenuation of reach.

(ii) Zone 2 line angle shall be set to tan-1 (X1/R1).

(iii) The Zone 2 operating time shall be 400 milliseconds.

(iv) Where Zone 2 element has a separate zero sequence compensation factor setting, the setting shall be the same as for Zone 1.

(v) Where a phase to earth fault quadrilateral characteristic is applied, the Zone 2 earth fault elements resistive axis reach setting shall be set to the associated value for Zone 1. The Zone 2 element shall detect a phase to earth fault having a resistance of 10 ohms located on or near the farthest remote station busbar with all fault current in-feeds considered.

(vi) Where zero sequence mutual impedance associated with an 'in-service' parallel transmission line impacts on the Zone 2 reach for phase to earth faults, the Zone 2 reach may need to be increased by increasing the zero sequence compensation factor.

(vii) Where zero sequence mutual impedance associated with an 'out–of-service and earthed' transmission line impacts on the Zone 2 reach for phase to earth faults, the setting may need to be reduced to comply with the reach constraint of not exceeding 50% of the shortest transmission line connected to the remote busbar.

(viii) Zone 2 setting shall take into account the constraints of load current and PSB settings.

(c) Zone 3 settings

(i) Zone 3 element reach shall be set to cover 150% of the apparent positive sequence impedance of the longest transmission line plus the longest protected line. As with Zone 2 settings, the impact of fault current in-feed at or near the reach point will be to attenuate the reach of the relay. In addition the setting shall be consistent with load current constraints and PSB characteristics if applied to the Zone 3 element.

(ii) Zone 3 line angle shall be set to tan-1 (X1/R1).

(iii) The Zone 3 operating time shall be 1.0 second.

(iv) Where Zone 3 element has a separate zero sequence compensation factor setting, the setting shall be the same as for Zone 1.

(v) Where a phase to earth fault quadrilateral characteristic is applied, the Zone 3 earth fault elements resistive axis reach setting shall be set to the associated value for Zone 1.

(vi) Where Zone 3 element has an offset characteristic, the reverse reach shall be set to 20% of the protected line Z1.

(vii) Load Encroachment element settings

The setting of impedance value for the load encroachment element shall be set according to equation:

$Z = (0.9 \times KV^2)/(1.1\ MVA)$ where kV is the nominal system voltage and MVA is the maximum rating of line equipment. The setting of angle should be based on worst line loading power factor +5 degrees safety margin.

5.3.3 Remote signalling for accelerated distance protection

For accelerated tripping of distance protection for faults close to the remote end busbar, the application of remote signalling is required. Accelerated distance is only required where current differential protection is not applied. The most appropriate application of signalling shall be selected for the associated transmission line arrangement from the following types of schemes:

(a) Permissive Underreach Transfer Trip (PUTT)

  (i) A permissive signal shall be sent to the remote end protection by the local protection when a fault is detected in zone 1.

  (ii) Receipt of a permissive signal from the remote end protection and detection of a fault in zone 2 shall initiate an immediate trip.

(b) Permissive Overreach Transfer Trip (POTT)

  (i) A permissive signal shall be sent to the remote end protection when a fault is detected by the local protection in zone 2.

  (ii) Receipt of a permissive signal from the remote end protection and detection of a fault in zone 2 shall initiate an immediate trip.

(c) Blocking scheme

  (i) When the distance protection is applied as a blocking scheme, an overreaching Zone 2 shall be set as the accelerated zone and shall be set to operate in 100 milliseconds providing the telecommunications network can operate in sufficient time.

  (ii) The accelerated zone shall be blocked by the starting operation of the remote end relay's reverse zone.

  (iii) The reverse zone shall be set to ensure that it reaches at least 20% further than the remote end accelerated zones under all network conditions and arrangements.

  (iv) The blocking scheme is to be configured to ensure that sequential circuit breaker clearances resulting in line current reversals will not inadvertently trip healthy lines.

  (v) The blocking signal shall be fail safe, i.e. a protection relay failure will result in a blocking signal being sent to the remote line ends.

5.3.4 Switch on to fault functionality and settings

Each transmission line protection scheme shall have the SOTF feature enabled to detect a fault, located at any point of the entire transmission line, on energisation of the transmission line. The following shall apply:

(a) Where the main protection consists of a distance protection scheme, the SOTF detector shall either be based on impedance or overcurrent threshold.

(b) The operation of the SOTF shall block the operation of the auto reclose scheme.

(c) The SOTF feature shall be set to remain in service for a period of 10 to 15 cycles (200 to 300 milliseconds) from energisation of the circuit breaker closing coil.

(d) The setting of the SOTF shall operate with certainty for a fault at the remote line end by having a setting of one half the minimum fault current for a fault at the remote line end.

5.3.5 Power swing blocking settings

(a) The distance protection scheme shall have the PSB feature enabled to block the operation of Zones 1, 2 and 3 in the event of a power swing condition.

(b) In the case of out of step tripping, PSB detection in zone 1 may be required to trip the circuit breaker; this feature, if required, shall be included in project specification.

(c) Where the PSB detection depends on the time taken by the impedance vector to traverse the impedance between two characteristics, the time delay shall be set to 40 milliseconds.

(d) Operation of PSB shall block the associated distance protection and provide an alarm to local and remote SCADA.

(e) PSB shall not be activated if either of the following conditions exist and following the operation of the PSB, the distance scheme shall be unblocked when either of the following conditions occur:

  (i) the measured residual current threshold is exceeded; or

  (ii) the measured negative sequence threshold current is exceeded.

5.4 Fault locator settings

(a) For overhead transmission lines, the fault locator shall be set to display distance to fault in kilometres.

(b) For composite transmission lines consisting of an overhead line section and a cable section, the fault locator shall be set to display impedance to fault in primary ohms.

5.5 VT supervision (VTS)

Each transmission line distance protection scheme shall have the VTS feature enabled and set as follows:

(a) The VTS feature shall detect a total failure of a VT supply to the scheme, (loss of all three phase voltages), or the loss of one or two phase voltages.

(b) The operation of the VTS feature shall instantaneously block the operation of the distance protection scheme and the operation of the auto reclose scheme, if the associated distance protection is in service, and provides an alarm output following a time delay of 3 seconds.

5.6 CT supervision (CTS)

Both the current differential protection scheme and the distance protection scheme shall have the CTS enabled and the operation of the CTS shall provide an alarm following a time delay of 5 seconds.

5.7 Broken conductor alarm

Broken conductor is to be enabled as an alarm only displying both locally and remotely.

Application of the setting must be as an I2/I1 ratio of 0.2 and a time delay of 60 seconds. Commissioning checks must be applied to ensure negative sequence currents do not exceed the application of the broken conductor setting.

6 Application of protection to composite overhead and cable section transmission lines

(a) As for normal transmission lines, current differential protection with back-up distance protection shall be applied to composite transmission lines where one or more cable section(s) exist in a transmission line.

(b) Zone 1 of the distance protection shall only be enabled on failure of the current differential protection or loss of the associated communications while zones 2 and 3 are enabled concurrently with the current differential protection. However, zone 1 may be enabled in addition to zones 2 and 3 in order to protect cable sections and inhibit auto reclose for faults within the cable section of the transmission line. Auto reclosing facilities shall be switched out of service upon loss of the current differential protection.

(c) For Composite transmission lines where the length of the overhead transmission line is less than 50% of the total length of the transmission line and where it is not practical to provide separate dedicated protection for the cable section, auto reclose facilities shall not be applied.

(d) Auto reclosing shall not be applied to three phase cables or oil filled cables.

6.1 Cable section at one or both ends of the transmission line – application and settings

The following points refer to the provision of protection on the cable section(s) in the event that the project specification demands that cable protection be applied:

(a) Where it is practical to provide duplicate CTs, communications facilities and auxiliary supplies, dedicated duplicated current differential protection schemes shall be applied to the cable section. Operation of the dedicated cable protection shall forward direct inter-trip signals to each line end and shall block the operation of any auto reclose function at each line end.

(b) For transformer feeders, where the cable section is located at the transformer end of the transmission line, the operation of the cable protection shall be combined with the output of transformer protection to trip the remote line end and to block any associated auto reclose function. The transmission line back-up distance protection shall also be set to reach through the cable connection to detect a fault at the remote line end.

(c) Where it is not possible or practical to apply dedicated duplicated differential protection to the cable section, zone 1 of the main ‘A’ and main ‘B’ distance protection schemes shall be enabled concurrently with the current differential protection and be set to reach 120% of the cable length provided that the zone 1 setting does not exceed 80% of the total transmission line length. The zero sequence compensation factors K0 applied to zone 1 shall be calculated from the cable characteristics. The distance protection shall trip the local line end circuit breaker and inhibit auto reclose and shall send a direct inter trip signal to trip the associated circuit breaker at the remote line end and inhibit auto reclose at that line end. Note that distance protection can only be applied at each line end in an interconnected network where a source exists at each line end. In the event that a source is not available at the line end to which the cable section is connected, e.g. a parallel transmission line is not in service the auto reclose on the transmission line shall be switched out of service.

(d) The conventional zone 1 setting of 80% of the transmission line length and the new zero sequence compensation factor setting K0, calculated from the cable plus the overhead transmission line characteristics, shall be applied to the back-up distance protection function to be enabled when the current differential protection is out of service.

6.2 Cable section located within the transmission line – application and settings

(a) Where the cable section is located within the transmission line and provided the total cable length does not exceed 10% of the transmission line length and it is not practical to apply dedicated current differential protection schemes to the cable section, auto reclosing shall be applied since there is a low probability that a transmission line fault will be located on the cable section.

(b) Where the project specification requests the application of auto reclose inhibition for faults on the cable section and where the section length is greater than 1 kilometre, zone 1 of the distance protection shall be enabled to be in service concurrently with the current differential protection and shall be set to cover 120% of the cable section from each line end provided that the reach setting does not exceed 80% of the total transmission line.

(c) Signalling is required between the line ends to ensure that the operation of the zone 1 elements at each line end inhibit the auto reclose facility at each line end. These settings assume that the zone 1 reach will not reach beyond 80% of the transmission line length. Zone 1 settings shall be in setting group 1. Please note that distance protection can only be applied at each line end in an interconnected network where a source exists at each line end. In the event that a source is not available at one line end, e.g. a parallel transmission line is not in service, the auto reclose on the transmission line shall be switched out of service.

(d) Zone 1 reach setting of 80% of the transmission line length and the new zero sequence compensation factor setting K0, calculated from the cable plus overhead transmission line characteristics up to 80% of the line length, shall be applied to the back-up protection function which shall be enabled when the current differential protection is out of service. The zone 1 setting shall be in setting group 2 which shall be enabled on loss of current differential protection.

7 CBF protection application

For Circuit Breaker Failure applications refer to the Protection of EHV Busbars Standard.

8 High impedance earth fault protection

8.1 Application

(a) High impedance earth fault protection shall be applied to all 220 kV and 110 kV transmission lines.

(b) The high impedance earth fault element shall be configurable to operate in a directional or a non-directional mode.

(c) A directional mode may be required to facilitate the grading of high impedance earth fault protection. In such cases, it shall be ensured that sufficient polarising voltage is available to allow unambiguous operation of the directional element.

8.2 Settings

(a) The high impedance earth fault element shall be set to detect an earth fault having a resistance up to 300 ohms on the 220 kV and the 110 kV systems.

(b) The time delay setting of the high impedance earth fault relay shall grade with the operating times of adjacent protection systems and shall have a margin of at least 1 second longer than the setting of the distance protection Zone 3 – but no longer than 4 seconds.

9 Auto reclosing

The following section describe the application of single pole auto reclose (SPAR) to 220 kV transmission lines and three pole auto reclose (TPAR) to 110 kV transmission lines.

9.1 SPAR application

The following sections deal with the application of SPAR to 220 kV interconnected transmission lines.

9.1.1 Single pole trip enabling

The bay control relay shall permit the two main protection relays to trip single pole when the following conditions are met:

(a) The bay control relay is in service and healthy.

(b) The auto reclose function is in enabled.

(c) The auto reclose function is not blocked.

(d) An auto reclose cycle is not in progress, in the dead or reclaim time.

9.1.2 SPAR initiation

(a) The SPAR function shall be initiated by the associated transmission line protection relays provided that, where applicable, all gas pressure and mechanical conditions in the circuit breaker are within set limits. The breaker conditions are determined by the bay control relay.

(b) SPAR shall be initiated by the operation of current differential and distance protection only.

(c) SPAR shall be initiated by the operation of the accelerated zone 2 distance protection only when communications signalling is applied.

(d) Time delayed protection schemes such as high impedance earth fault protection and distance protection without permissive signalling shall not initiate auto reclosing.

9.1.3 SPAR blocking

The SPAR blocking signal shall still be effective after the initiation of the auto reclose sequence. The operation of the SPAR auto-reclose scheme shall be blocked under the following conditions:

(a) Fault detection on more than one phase.

(b) Failure of both protection relays associated with the auto reclose device.

(c) Any manual reclose operation of the associated circuit breaker(s) (for the period of the reclaim time).

(d) Operation of the high impedance earth fault protection.

(e) Operation of a time delayed element of the associated transmission line protection relays (e.g. zone 2 or zone 3 of the distance protection).

(f) Operation of the SOTF on the associated transmission line protection relays.

(g) Enabling of stub protection mode in the associated transmission line protection relays.

(h) Operation of the circuit breaker failure protection.

(i) Operation of cable unit protection installed on the cable section(s) at the ends of composite transmission lines.

9.1.4 SPAR settings

(a) The dead time setting on the auto-reclose relay for SPAR shall be 700 milliseconds.

(b) The reclaim time shall be set to 20 seconds.

(c) The SPAR shall be set to single shot.

9.2 TPAR application

TPAR is generally applied to the 110 kV system but may be applied to sections of the 220 kV system if SPAR is not implemented.

9.2.1 TPAR conditions

Where TPAR is associated with an interconnected transmission line, the following sequential restoration procedure for the transmission line shall be applied in order to fulfil requirements for checking synchronisation:

(a) The first line-end shall auto-reclose under the pre-condition of 'dead line-live bus'.

(b) The other line-end shall either be reclosed manually following synchronising check or by auto-reclose under the pre-condition of 'live line-live bus' together with synchronising check.

9.2.2 TPAR Initiation

(a) The TPAR function shall be initiated by the associated transmission line protection relays provided that, where applicable, all gas pressure and mechanical conditions in the circuit breaker are within set limits.

(b) TPAR shall be initiated by single or multi-phase operation of the current differential, zone 1 or accelerated zone 2 distance protection only.

(c) TPAR shall be initiated by the operation of the accelerated zone 2 distance protection only when communications signalling is applied.

(d) Time delayed protection elements such as high impedance earth fault protection and zone 2 and zone 3 distance protection without permissive signalling shall not initiate TPAR.

9.2.3 TPAR blocking

The TPAR blocking signal shall still be effective after the initiation of the auto reclose sequence. The operation of TPAR shall be blocked under the following conditions:

(a) Failure of both protection relays associated with the auto reclose device.

(b) Any manual reclose operation of the associated circuit breaker(s) (for the period of the circuit breaker reclaim time).

(c) Operation of the high impedance earth fault protection.

(d) Operation of a time delayed element of the associated transmission line protection relays (e.g. zone 2 or zone 3 of the distance protection).

(e) Operation of the SOTF on the associated transmission line protection schemes.

(f) CBF protection operation.

(g) Operation of cable unit protection on composite transmission lines.

9.2.4 TPAR settings

(a) Where only one line end is reclosed by TPAR, the 'dead time' for TPAR shall be 5 seconds.

(b) Where two line ends are being reclosed by TPAR, the 'dead time' for the initial line end shall be 5 seconds and 7 seconds for the second line end.

(c) The reclaim time setting shall be 20 seconds.

(d) The synchronising check function shall be enabled automatically for TPAR operations.

9.3 Application to a double circuit breaker transmission line end

The auto reclose function together with any associated logic shall be included in the bay control relay provided for the respective EHV circuit breaker.

9.3.1 Application for 220 kV transmission lines

Where both circuit breakers are capable of SPAR, each breaker shall auto reclose.

Where only one circuit breaker is capable of SPAR or where only one circuit breaker is fitted with SPAR, this breaker shall be tripped single pole for phase to earth fault conditions and the second circuit breaker shall be tripped three pole. Following successful SPAR, three pole reclose of the second circuit breaker shall take place following a synchronising check.

9.3.2 Application for 110 kV transmission lines

Where the 110 kV transmission line is part of the interconnected system, TPAR shall be arranged such that the line ends close sequentially. For operational purposes, one line end is chosen as the first line end to close and for the purposes of discussion here, this line end is referred to as the 'local' line end. The other line end is referred to as the 'remote' line end. TPAR shall be carried out according to the following procedure:

(a) At the local line end, one of the transmission line circuit breakers shall be selected to auto reclose first.

(b) The auto reclosing scheme at the local line end is arranged to operate in the 'live bus dead line' mode and a 'live line blocking' feature shall be provided to ensure that reclosing is not possible if the line is alive. Note: For double breaker configurations, where a breaker is connected to 'A' bus, the voltage used to determine the status of the bus is derived from bus 'A'. Similarly the voltage used for check synchronising is derived from the busbar associated with the other circuit breaker.

(c) The second circuit breaker at the local line end is reclosed subject to establishing that:

  (i) the first circuit breaker is closed, the 'live line – live bus' condition is satisfied;

  (ii) a short time lag has expired, (approximately 1 second); and

  (iii) a synchronising check has been carried out; (this is necessary since bus 'A' and bus 'B' may be associated with different portions of a split system).

(d) If TPAR is also required at the remote line end and a double breaker configuration exists at the remote line end, both circuit breakers shall be arranged in the 'live line – live bus' mode and both reclose following synchronising check for each circuit breaker (the dead time setting for the initiating line end is 5 seconds and the dead time for the remote line end is 7 seconds).

(e) Where only one of the double breakers is in service, the auto reclose signal to the out-of-service breaker shall be blocked.

Where the double breaker configuration is associated with a radial transmission line, TPAR for both breakers shall be implemented subject to the constraints that both breakers are in service and that the transmission line is dead and the appropriate bus bars are alive.

9.4 Application to a breaker and a half transmission line

Each circuit breaker bay control relay is equipped with an auto reclose device capable of both TPAR and SPAR. When required, SPAR shall be selected for 220 kV transmission lines and TPAR shall be selected for 110 kV transmission lines.

9.4.1 Application for 220 kV transmission lines

If all circuit breakers in the arrangement are capable of single pole tripping and reclosing, SPAR shall be applied to each circuit breaker. Similar procedures to those mentioned in section 9.3 shall be implemented for auto reclosing the two associated circuit breakers simultaneously.

Similar procedures to those mentioned in section 9.3 shall be implemented for auto reclosing the associated circuit breaker sequentially.

At sites where IEC 61850 process and/or station bus is implemented, all design requirements shall be in accordance with the TasNetworks IEC 61850 Protection and Automation Standard.

9.4.2 Application for 110 kV transmission lines

Similar conditions shall apply for this arrangement as mentioned in section 9.3. However, in this case the initiating circuit breaker shall be the bus circuit breaker and the second breaker is the centre circuit breaker. The second line end breakers are the appropriate bus circuit breaker and the corresponding centre circuit breaker.

10 Check and System Synchronisation Settings

Check and system synchronisation settings are to be requested from TasNetworks.

11 Trip circuit supervision application

(a) Trip circuit supervision facilities shall be available in the main ‘A’ protection and the main ‘B’ protection.

(b) The trip circuit supervision function shall supervise the health of the ‘A’ and ‘B’ tripping circuits and circuit breaker trip coils respectively when the circuit breaker is in the open or the closed position.

(c) The circuitry shall be arranged such that the trip circuit supervision covers as much tripping circuitry as possible. To this end, the trip circuit supervision shall be located at the end of the tripping circuit such that an interruption in the tripping supply to the isolating links of the various functions will be detected by the trip supervision device.

(d) Failure of one of the trip circuits shall not block the operational closing function of the circuit breaker.

(e) Failure of both of the trip circuits shall block the operational closing function of the circuit breaker.

(f) Separate trip circuit supervision facilities for 220 kV circuit breakers capable of SPAR shall be available for each of the two trip coils on each phase.

(g) Trip circuit supervision for the middle circuit breaker of a circuit breaker and a half configuration and for each circuit breaker associated with a double breaker configuration shall be performed by the associated bay control relay.

(h) Trip circuit supervision for the circuit breakers located at the bus ends of the circuit breaker and a half diameter shall be performed in the main ‘A’ and main ‘B’ protection relays.

12 Testing

General testing requirements are detailed in the Testing, Commissioning and Training standard.

Specific testing requirements are detailed in TasNetworks' Secondary Equipment Testing Standard.