

# Protection Common Functional Requirements

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## 1. Purpose

This document details the principles for the application, design and setting of ElectraNet's protection systems.

## 2. Scope

This document defines the principles for the application, design and setting of all protection systems applied to ElectraNet's 330 kV, 275 kV, 132 kV and 66 kV transmission network assets, including transformer low voltage and tertiary voltage connections.

## 3. Terms and acronyms

Acronym or initialism	Definition
AR	Auto-reclose, is the automatic reclosure of a circuit-breaker after a predetermined time following a fault tripping.
AVR	Automatic Voltage Regulation, is the monitoring of the voltage at a voltage regulating point on the system and the initiation of automatic corrective action to maintain that voltage within pre-set limits.
BAAH	Breaker-And A-half, Is a double-bus arrangement where, for two circuits, three circuit-breakers are connected in series between the two buses, the circuits being connected one each side of the central circuit-breaker.
CB	Circuit Breaker, is a mechanical switching device, capable of making, carrying and breaking currents under normal circuit conditions and also making, carrying for a specified duration and breaking currents under specified abnormal circuit conditions such as those of short circuit.
CBF	Circuit Breaker Failure protection, is protection which is designed to clear a system fault by initiating tripping of other circuit-breaker(s) in the case of failure to trip of the appropriate circuit-breaker.
CT	Current Transformer, is a transformer for use with meters and/or protection devices in which the current in the secondary winding is, within prescribed error limits, proportional to and in phase with the current in the primary winding.
DC	Direct Current. Is an electric current that is time-independent.
DEF	Directional Earth Fault protection, is a protection scheme that senses the direction in which earth fault occurs and only operates for fault in a particular direction.
DT	Definite Time-delay overcurrent release, is an overcurrent release which operates with a definite time-delay, which may be adjustable, but is independent of the value of the overcurrent.
IDMT	Inverse Definite Minimum Time protection, is protection in which the time taken to operate is inversely proportional to the overcurrent.
IED	Intelligent Electronic Device, is an integrated microprocessor-based controller of power system equipment
IPS	Intelligent Process Solutions, is the name given to the software used by ElectraNet to store and manage protection relay and other intelligent electronic device (IED) setting information.

Acronym or initialism	Definition
MTBF	Mean Time Between Failure, is the average time between repairable failures of a technology product.
MTTF	Mean Time To Failure, the average amount of time a technology product is in service before it fails.
MTTR	Mean Time to Repair, is the average time it takes to repair a technology product.
NER	National Electricity Rules, are rules made under the national electricity law and govern the operation of the national electricity market.
PSM	Plug Setting Multiplier, is the ratio between the actual fault current in the relay operating coil to pick up current or the relay current setting. Plug setting multiplier Indicates the severity of the fault. The plug setting multiplier is used only in Electromagnetic relays, not in IED relays.
REF	Restricted Earth Fault, is earth fault from a restricted or localised zone of a circuit. REF does not to sense any earth faults outside this restricted zone.
SOTF	Switch-On-To-Fault protection, is used to trip a transmission line breaker when the breaker closes into a faulted line.
SIR	System Impedance Ratio, is the ratio of the source impedance, $Z_s$ , to the line impedance, $Z_L$ . The SIR is a used to classifying the electrical length of a transmission line for the purpose of setting protective relays.
TCS	Trip Circuit Supervision, is a function, normally performed within the protection equipment, that automatically to detects failures within the trip circuit.
VT	Voltage Transformer, is a transformer for use with meters and/or protection devices in which the voltage across the secondary terminals is, within prescribed error limits, proportional to and in phase with the voltage across the primary terminals.

## 5. Application and design requirements for protection systems

### 5.1. Safety requirements

Protection systems are classified, by ElectraNet, as safety critical systems and consequently must be designed such that single component failure must not prevent the protection system from operating when it is required to do so.

*Informative: In the context of this document structure, failure must mean failure to operate, or failure to operate within a specified maximum operating time, or in a time whereby other protection has sufficient time to perform a correct back-up function.*

#### 5.1.1. General requirements

In the context of this document structure a protection system is defined in accordance with IEC 60050-448 and refers to an arrangement of one or more items of protection equipment, and other devices intended to perform one or more specified protection functions. A protection system includes one or more items of protection equipment, instrument transformers, wiring, trip circuits, auxiliary supplies, and communication systems. Depending upon the principles of the protection system, it may include one or all ends of the protected object.



#### **5.1.1.1. Protection system philosophy**

Protection systems must be designed such that all power system faults are detected by at least two independent, high speed main protection systems, designated as Set 1 and Set 2. The outputs of the protection system must be selectively allocated to independent tripping systems supplied from separate DC systems. The Set 1 and Set 2 protection systems must avoid the use of common hardware and common software to minimise the risk of common mode failure and common setting error. To cater for the failure of downstream protection systems, back-up protection functionality must be provided within both Set 1 and Set 2 protection systems. In addition, duplicated CBF protection must be provided to clear faults occurring within dead zones and to cater for the failure of circuit breakers and their associated tripping systems. The circuit breaker failure protection must be arranged to trip and transfer trip all contiguous circuit breakers.

*Informative: A dead zone occurs within a substation between a protection zone and a circuit breaker adjacent to that protection zone that is required to open and clear the fault.*

#### **5.1.1.2. Protection system selectivity**

In the event of a power system fault occurring on the equipment that the protection systems are deployed to protect, both Set 1 and Set 2 protection systems are required to rapidly detect the fault and initiate the opening of all the circuit breakers that are required to be opened in order to isolate the faulted equipment from the power system. Protection systems must be capable of discriminating between faults occurring on adjacent items of equipment and faults occurring on the item of equipment they are deployed to protect.

#### **5.1.1.3. Protection system sensitivity**

Protection systems must be configured to clear all faults occurring on the equipment they are deployed to protect whilst remaining secure under all rated loading conditions.

#### **5.1.1.4. Protection system operating speed**

Protection systems must be designed such that the total fault clearance times are in accordance with the maximum fault clearance times specified within the current version of the NER.

#### **5.1.1.5. Protection system security**

Protection systems must be designed to allow the primary system 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. Unit protection schemes must remain stable when exposed to out of zone faults.

#### **5.1.1.6. Protection trip outputs**

All protection trip outputs must be configured for unlatched operation and be equipped with a means of local isolation.

#### **5.1.1.7. Equipment technology**

ElectraNet's protection systems must be established utilising microprocessor-based equipment that can provide integrated functionality, a high degree of self-supervision, event recording, oscillography and information exchange via communication channels. Electromechanical and static analogue electronic based protection systems must not be deployed. The requirements for equipment hardware platforms are specified within 1-09-FR-36 Equipment Hardware and Software.

### 5.1.1.8. Setting group definitions

All protection systems must be capable of supporting a service setting group plus a minimum of three user selectable contingency setting groups. Setting Group selection must be available from both local and remote facilities.

## 5.1.2. Instrument transformers for use in protection systems

### 5.1.2.1. Current transformers

Current transformers for use in primary protection systems must meet the requirements of IEC 61869 -2, Class PX. Current transformers for use in backup protection systems must meet the requirements of IEC 61869-2, Class PX or Class P.

### 5.1.2.2. Voltage transformers

Voltage transformers for use in protection systems must meet the requirements of IEC 61869-33, Class 3P.

## 5.1.3. Feeder protection systems

For all feeder protection applications, redundant Set 1 and Set 2 feeder protection systems must be arranged to operate on an either-one-out-of-two tripping philosophy. Each of the Set 1 and Set 2 feeder protection systems must incorporate the following functionality:

- (a) Main protection;
- (b) Direct transfer trip send and direct transfer trip receive;
- (c) Back-up protection;
- (d) DEF protection;
- (e) CBF protection (for both controlling circuit breakers);
- (f) Stub bus protection;
- (g) Switch on to fault protection;
- (h) Fault location;
- (i) AR initiation and blocking; and
- (j) Feeder overload protection.

### 5.1.3.1. Main protection

The preferred feeder main protection arrangement is for both Set 1 and Set 2 protection systems to employ current differential protection systems in accordance with the requirements specified within 1-09-FR-02 Feeder Differential Protection. An alternative arrangement for Set 1 to employ a current differential protection system and for Set 2 to employ a communications aided distance protection system. The requirements of the distance protection system are specified within 1-09-FR-03 Feeder Distance Protection. Both the current differential and distance protection systems must be capable of directly transferring a local trip signal to the remote end via associated communication channels. ElectraNet may specify, within the contract-specific documentation, which of the two feeder main protection arrangements may be deployed.

### 5.1.3.2. Exclusion of current differential protection

Feeder current differential protection systems must be deployed for all feeder main protection systems except where suitable communication channels are not available. Under this situation, distance protection system(s) must be deployed.

### 5.1.3.3. Exclusion of distance protection

The circumstances in which distance protection systems must not be deployed as a feeder main protection system are:

- (a) On feeders where duplicate current differential protection can be deployed;
- (b) On feeders not equipped with three phase voltage transformers;
- (c) On feeders that are either compensated by series capacitors or adjacent to feeders that are compensated by series capacitors; or
- (d) On feeders of insufficient electrical length to allow a distance protection system to comply with the selectivity requirements of Section 5.1.1.2.

### 5.1.3.4. Direct transfer trip

To ensure faults are selectively isolated under all fault levels, on both interconnected and radial feeders, the main protection must, on detection of faults, transfer phase segregated direct trip signals to the remote end(s). Back-up protection and circuit breaker failure protection must transfer three phase direct trip signals to the remote end(s). The requirements for protection signalling are specified within 1-09-FR-09 Protection Signalling and Intertripping.

### 5.1.3.5. Back-up protection

Time-stepped and overreached distance protections must be applied as feeder back-up protection. Within feeder current differential protection systems, this arrangement must be permanently activated.

In applications where back-up distance protection cannot be deployed, a 3-phase overcurrent protection with a DT characteristic must be applied as the back-up protection. The requirements of three phase overcurrent protection are specified within 1-09-FR-06 Overcurrent Protection.

### 5.1.3.6. Directional earth fault protection

Where the sensitivity requirements defined within Section 5.1.1.3 cannot be achieved, the main protection must be supplemented by the addition of a directional earth fault protection system based on DT overcurrent protection. The DEF protection system must be arranged to co-ordinate selectively with the main protection. The requirements for overcurrent derived DEF protection are specified within 1-09-FR-06 Overcurrent Protection.

### 5.1.3.7. Stub bus protection

Stub bus protection must be applied to all feeders connected in ring bus, BAAH or double breaker configurations and must be configured to isolate faults which occur between the feeder's current transformers and the open line disconnecter. The preferred arrangement for stub protection is to be integrated into the feeder main protection system's differential or distance protection functions. Where this cannot be achieved, stub protection must be based on an overcurrent function with IDMT characteristic. The requirements for overcurrent derived stub bus protection are specified within 1-09-FR-06 Overcurrent Protection. Stub bus protection must be conditioned by the line disconnecter status and must only be active when the line disconnecter is in the open status.

#### 5.1.3.8. SOTF protection

SOTF is used to provide high-speed tripping when energising a faulted feeder. This is accomplished by enabling overreaching directional and nondirectional protection elements for a short window of time shortly after the transmission line breaker closes.

#### 5.1.3.9. CBF protection

Phase segregated, current and status checked CBF protection must be located within the feeder protection system for each of the feeder's controlling circuit breakers. The requirements for CBF protection are specified within 1-09-FR-10 Circuit Breaker Failure Protection.

#### 5.1.3.10. Fault location

At least one set of feeder protection systems must provide fault location facilities on the protected line with the accuracy of better than 5% of feeder length.

#### 5.1.3.11. Circuit breaker automatic reclose initiation and blocking

AR initiation and blocking functions must satisfy the following requirements:

- (a) AR functions must be initiated by the reset of feeder main protection operations resulting from single phase to ground faults; and
- (b) All protection functions, other than clause 5.1.3 (a) must block AR systems.

The requirements for the AR function are specified within 1-09-FR-02 Feeder Differential Protection, 1-09-FR-03 Feeder Distance Protection and 1-09-FR-17 Automatic Reclose Switching documents respectively.

#### 5.1.3.12. Feeder overload protection

Feeder overload protection is a contract specific function that must be provided for any transmission lines whose loading is not managed through constraints equations. A three-phase overcurrent with DT characteristic must be applied to monitor the current through the transmission line and be configured to trip all local and remote controlling circuit breakers. The requirements of three phase overcurrent protection are specified within 1-09-FR-06 Overcurrent Protection.

### 5.1.4. Circuit breaker management systems

A circuit breaker management system must be deployed for each circuit breaker. The circuit breaker management system must consist of a multifunction IED and a single function device. The single function device must provide the TCS function for the Set 2 trip system. The multifunction IED must incorporate the following functionality:

- (a) Synchronising;
- (b) AR;
- (c) TCS for the Set 1 trip system;
- (d) Overload protection; and
- (e) Commissioning overcurrent.

*Informative: ElectraNet's preference is for circuit breaker pole discrepancy protection to be integrated into the associated circuit breaker's control circuits.*

#### 5.1.4.1. Synchronising

The synchronising function must be utilised for both automatic and manual closing of a circuit breaker. The requirements for the synchronising function are specified within 1-09-FR-15 Synchronising document.

#### 5.1.4.2. Automatic reclose

The AR must be implemented within the circuit breaker management IED and must be performed in conjunction with the AR initiate and AR block signals initiated from feeder protection systems according to Section 5.1.3.11. The AR function must satisfy the following requirements:

- (a) AR functions must be limited to a single re-close attempt, power system faults occurring within the reclaim time must result in a reclose lockout condition;
- (b) AR functions must be capable of being manually switched in and out of service;
- (c) AR functions must be blocked immediately following CB supervisory close operations; and
- (d) AR functions must be applied to both single pole and three pole CBs.
- (e) The requirements for AR function are specified within 1-09-FR-17 Auto-reclose Switching

*Informative: The reclaim time is a period which is commenced following a circuit breaker automatic re-close.*

#### 5.1.4.3. Trip circuit supervision

TCS must be applied to every circuit breaker trip system and must monitor the trip supply, trip circuit field cables and CB trip coil. Trip systems must be monitored with the CB in both the open and closed positions. In the event of a trip circuit failure the TCS must initiate local and remote alarms. The requirements for TCS function are specified within 1-09-FR-13 Trip Circuit Supervision.

#### 5.1.4.4. Circuit breaker overload protection

A three-phase overcurrent with DT characteristic must be applied to all circuit breakers deployed in ring bus, BAAH or double breaker configurations. The protection must monitor the current through the circuit breaker and be configured to initiate local and remote alarms. The requirements of three phase overcurrent protection are specified within 1-09-FR-06 Overcurrent Protection.

#### 5.1.4.5. Commissioning overcurrent

Selectable three phase overcurrent with DT characteristic must be applied to all circuit breakers. If selected into service, the protection must monitor the current through the circuit breaker and be configured to trip the circuit breaker. The requirements of three phase overcurrent protection are specified within 1-09-FR-06 Overcurrent Protection.

### 5.1.5. Transformer protection systems

For all transformer protection applications, redundant Set 1 and Set 2 transformer protection systems must be arranged to operate on an either-one-out-of-two tripping philosophy. Each of the Set 1 and Set 2 transformer protection systems must incorporate the following functionality:

- (a) Main protection;
- (b) Back-up protection;
- (c) Mechanical protection management;
- (d) Neutral overcurrent protection;

- (e) Overload protection;
- (f) Tertiary winding protection;
- (g) Auxiliary transformer protection; and
- (h) High side CBF protection.

#### **5.1.5.1. Main protection**

The main protection arrangement must comprise of a phase segregated, two stage differential protection system. Stage 1 must be a load restrained, low set differential protection function. Stage 2 protection must be an unrestrained, high set differential protection function. Highset instantaneous overcurrent protection may be applied as a substitute to unrestrained, high set differential protection. In applications where transformer secondary windings are non-effectively earthed the differential protection must be supplemented by the application of REF protection. The requirements for transformer differential protection are specified within 1-09-FR-04 Non-feeder Differential Protection.

#### **5.1.5.2. Back-up protection**

Three phase overcurrent protection with IDMT characteristic must be applied to transformer high side as back-up protection. In applications where transformer secondary windings are non-effectively earthed, an additional neutral overcurrent protection with DT or IDMT characteristic must be applied to transformer low side neutral connection as a backup protection. The neutral overcurrent element must be supplied from a current transformer mounted on the low side winding's neutral connection. The backup protection must be arranged to operate selectively with the overload protection specified within Section 5.1.5.4. The detailed requirements for phase and neutral overcurrent protection are specified within 1-09-FR-06 Overcurrent Protection.

#### **5.1.5.3. Mechanical protection management**

Transformer protection systems must initiate protection trips based on the received operation signals from transformer mechanical protection devices.

Each of Set 1 and Set 2 protection systems must be equipped with sufficient optical inputs to manage two Buchholz relay trips, three winding temperature trips, one oil temperature trip and one pressure relief device trip. The detailed requirements for mechanical protection are specified within 1-09-FR-08 Mechanical Protection.

#### **5.1.5.4. Neutral overcurrent protection**

For the transformers with low side windings earthed through a resistance or reactance, protection of the neutral earthing resistor or reactor must be provided by a single overcurrent element with DT or IDMT characteristic. The overcurrent element must be supplied from a current transformer mounted on the low side winding's neutral connection. The requirements for neutral overcurrent are specified within 1-09-FR-06 Overcurrent Protection.

#### **5.1.5.5. Overload protection**

Current based transformer overload protection must be applied to any power transformers that are:

- (a) Used to provide a connection to the distribution network;
- (b) Used to provide a connection to a Transmission Network User; or
- (c) May be operated beyond their nameplate capacity.

Three phase overcurrent with DT characteristic must be applied to the low side of transformer as overload protection. The overload protection must be arranged to operate selectively with the high

side back-up protection as specified within Section 5.1.5.2. The requirements for 3-phase high side overcurrent protection are specified within 1-09-FR-06 Overcurrent Protection.

#### **5.1.5.6. Tertiary winding protection**

For the transformers that are equipped with a stabilising winding, the preferred protection arrangement for the tertiary winding is to be integrated into the transformer main differential protection. Discreet tertiary earth fault protection must only be applied in instances where the differential protection is unable to provide the required sensitivity to adequately protect tertiary winding. Where discreet tertiary winding protection is required, it must be provided by an overcurrent function with IDMT characteristic supplied from a current transformer mounted on the neutral earth connection. The requirements for overcurrent derived tertiary winding protection are specified within 1-09-FR-06 Overcurrent Protection.

#### **5.1.5.7. Auxiliary transformer protection**

Tertiary connected auxiliary transformers must be included within the transformer main protection zone, unless:

- (a) Faults on the low side of auxiliary transformer terminals would cause operation of the power transformer main protection; or
- (b) The auxiliary transformer rating exceeds 2% of the transformer rating.

Under the above circumstances, the auxiliary transformers must be equipped with overcurrent protection installed on both high side and low side. ElectraNet will specify, on an individual contract basis, where auxiliary transformers must be excluded from the main protection zone.

#### **5.1.5.8. High side CBF protection**

Three phase current and status checked CB failure protection must be located within the transformer protection system for each of the transformer high side controlling circuit breakers. The requirements of circuit breaker failure protection are specified within 1-09-FR-10 Circuit Breaker Failure.

### **5.1.6. Transformer low side protection systems**

The transformer low side protection systems must consist of redundant Set 1 and Set 2 multifunction IEDs. The protection systems must be arranged to operate on an either-one-out-of-two tripping philosophy. Each of the Set 1 and Set 2 transformer protection systems must incorporate the following functionality:

- (a) CBF protection; and
- (b) TCS monitoring.

*Informative: Where the transformer low side is arranged as a transformer ended feeder the low side protection system may be integrated into the feeder protection system.*

#### **5.1.6.1. CBF protection**

Three phase current and status checked circuit breaker failure protection must be applied for each of the transformer low side controlling circuit breakers. The requirements of circuit breaker failure protection are specified within 1-09-FR-10 Circuit Breaker Failure.

#### **5.1.6.2. TCS function**

TCS must be applied to the low side circuit breaker trip systems and must monitor the trip supply trip circuit field cables and CB trip coil. Trip systems must be monitored with the CB in both the open

and closed positions. In the event of a trip circuit failure the TCS must initiate local and remote alarms. The requirements for TCS function are specified within 1-09-FR-13 Trip Circuit Supervision.

### **5.1.7. Shunt reactor protection systems**

For all reactor protection applications, redundant Set 1 and Set 2 reactor protection systems must be arranged to operate on an either-one-out-of-two tripping philosophy. Each of the Set 1 and Set 2 reactor protection systems must incorporate the following functionality:

- (a) Main protection;
- (b) Backup protection
- (c) Mechanical protection management; and
- (d) CBF protection.

#### **5.1.7.1. Main protection**

The main protection arrangement must comprise of a phase segregated, two stage differential protection system. Stage 1 must be a load restrained, low set differential protection function. Stage 2 protection must be an unrestrained, high set differential protection function. Highset instantaneous overcurrent protection may be applied as a substitute to unrestrained, high set differential protection. The requirements for reactor differential protection are specified within 1-09-FR-04 Non-Feeder Differential Protection.

#### **5.1.7.2. Backup protection**

Three phase overcurrent protection with a DT characteristic must be applied to shunt reactors as back-up protection. The detailed requirements for overcurrent protection are specified within 1-09-FR-06 Overcurrent Protection.

#### **5.1.7.3. Mechanical protection management**

Reactor protection systems must initiate protection trips based on the received operation signals from reactor mechanical protection devices.

Each of Set 1 and Set 2 protection systems must be equipped with sufficient optical inputs to manage two Buchholz relay trips, one winding temperature trips, one oil temperature trip and one pressure relief device trip. The detailed requirements for mechanical protection are specified within 1-09-FR-08 Mechanical Protection.

#### **5.1.7.4. CBF protection**

Three phase current and status checked circuit breaker failure protection must be located within the reactor protection systems for its controlling circuit breaker. The requirements of circuit breaker failure protection are specified within 1-09-FR-10 Circuit Breaker Failure.

### **5.1.8. Bus protection systems**

For all bus protection applications, redundant Set 1 and Set 2 bus protection systems must be arranged to operate on an either-one-out-of-two tripping philosophy. Each of the Set 1 and Set 2 bus protection systems must incorporate the following functionality:

- (a) Main protection; and
- (b) CBF protection.



### 5.1.8.1. Main protection

The main protection arrangement must comprise of a phase segregated, two stage differential protection system. Stage 1 protection must be a load restrained, low set differential protection function. Stage 2 protection must be an unrestrained, high set differential protection function. Highset instantaneous overcurrent protection may be applied as a substitute to unrestrained, high set differential protection. The requirements for bus differential protection are specified within 1-09-FR-04 Non-Feeder Differential Protection.

### 5.1.8.2. CBF protection

Three phase current and status checked circuit breaker failure protection must be located within the bus protection system for each circuit breaker connected to the protected bus. The requirements of circuit breaker failure protection are specified within 1-09-FR-10

## 5.1.9. Shunt capacitor bank protection systems

For all capacitor bank protection applications, redundant Set 1 and Set 2 capacitor bank protection systems must be arranged to operate on an either-one-out-of-two tripping philosophy. Each of the Set 1 and Set 2 capacitor bank protection systems must incorporate the following functionality:

- (a) Overcurrent protection;
- (b) Overvoltage protection;
- (c) Dead bus protection; and
- (d) CBF protection.

### 5.1.9.1. Overcurrent protection

The following overcurrent protection must provide the following functionality:

- (a) An unbalance overcurrent protection function with DT characteristic according to 1-09-FR-06 Overcurrent Protection;
- (b) An instantaneous three phase overcurrent protection function according to 1-09-FR-06 Overcurrent Protection
- (c) A three-phase overcurrent protection function with DT characteristic according to 1-09-FR-06 Overcurrent Protection;
- (d) An earth fault protection function with DT characteristic according to 1-09-FR-06 Overcurrent Protection;
- (e) A harmonic overload protection function with DT characteristic according to 1-09-FR-05 Thermal Overload Protection; and
- (f) A dead bus protection function.

### 5.1.9.2. Overvoltage protection

Voltage protection arrangement must be provided by the following functionalities according to 1-09-FR-07 Overvoltage and Loss of Voltage Protection:

- (a) An overvoltage protection function with DT delay;
- (b) A harmonic overvoltage protection function; and
- (c) A dead bus protection function.

### 5.1.9.3. Dead bus protection

Dead bus protection may be supplied from voltage or current references, and consequently may be included in either the overcurrent or overvoltage protection system. The dead bus protection must be arranged to trip the capacitor bank on loss of supply, following a short delay.

### 5.1.9.4. CBF protection

Three phase current and status checked circuit breaker failure protection must be located within the capacitor bank's protection systems for its controlling circuit breaker. The requirements of circuit breaker failure protection are specified within 1-09-FR-10 Circuit Breaker Failure.

### 5.1.10. AVR systems

An AVR system must be provided at every connection point on ElectraNet's transmission network, to maintain the required bus voltage level. The detailed requirements of the function are specified in 1-09-FR-18 Automatic Voltage Regulation.

### 5.1.11. Instrument transformer monitoring and supervision

#### 5.1.11.1. Current transformer supervision

Current transformers deployed in protection systems must be provided with supervisory facilities to initiate an alarm in the event of any of the following conditions

- (a) Open or short circuit winding; or
- (b) Open or short circuit secondary connections.

#### 5.1.11.2. Voltage transformer supervision

CVT must be provided with supervisory facilities to initiate an alarm in the event of any of the following conditions:

- (a) Overvoltage;
- (b) Undervoltage;
- (c) Voltage differential between phases; or
- (d) Negative sequence voltage magnitude.

*Informative: For applications in which only a single phase CVT is available, voltage differential must be applied through comparison with another CVT on the same phase of a different circuit.*

## 5.2. Constructability requirements

The protection system must be designed with the following features:

- (a) Each protection device must be designed such that its input / output capability is expandable. The preferred method of expansion is through the addition of modular input / output boards. Protection systems that do not support the expansion of input / outputs must be equipped a minimum of two normally open spare output contacts and two spare digital inputs;
- (b) Hardware and software requirements as defined within 1-09-FR-36 Equipment Hardware and Software;
- (c) Accommodation requirements as defined within 1-09-FR-26 Cubicle and Panel;
- (d) Circuitry and connections requirements as defined within 1-09-FR-27 Circuitry; and

- (e) Clearly labelled test and isolation facilities must be provided at the front of protection and control cubicles. The labelling nomenclature must be consistent with the nomenclature used to identify the equipment in the design drawings.

### 5.3. Maintainability requirements

Protection systems must be designed with the maintenance facilities described below:

- (a) Each protection device must be equipped with self-monitoring and diagnostic capabilities to minimise hidden failures;
- (b) Where equipment incorporates firmware, a unique number, traceable to the release of the firmware and the version of the system to which it pertains, must be clearly marked on the component, or be available from the informative interface, as well as being documented in the instruction manual;
- (c) Maintenance aids such as printed wiring extension boards, jumper leads, and other special tools must be provided;
- (d) Each protection device, which is in service, must be capable of being safely and individually isolated from the rest of secondary system without the need for primary system outages, specialist tools and knowledge. This requirement extends to current transformer circuits, voltage transformer circuits, DC supplies and control and tripping circuits;
- (e) If the device, which is to be isolated, is connected to other device(s) to form a protection system (e.g. feeder protection), the isolation must be conditioned with the isolation status of the remotely connected device(s);
- (f) Each protection device must be capable of being tested by analogue and digital injections from an external test set after being isolated from the rest of secondary system. This requirement is also extended to the ability to monitor communication messages to the substation automation system;
- (g) A live trip test facility, which operates the selected phase of the selected circuit breaker, must be provided for each protection device;
- (h) The live trip test facility must not initiate CBF functions;
- (i) The live trip test facility must initiate AR function for the selected phase of the selected circuit breaker; and
- (j) If a protection device becomes defective, the failed equipment must be capable of being removed and replaced without primary system outages.

### 5.4. Operability requirements

The protection system must be designed to meet the speed, sensitivity, security, and selectivity requirements specified in clause 5.1.1 for all foreseeable power system operating conditions.

*Informative: The application of contingency protection setting groups is an accepted limitation which may result in a degradation in selectivity and / or security.*

### 5.5. Availability requirements

The protection system design must comply with the availability requirements listed in 1-09-ACS-01 Protection System – Digital.

## 5.6. Reliability requirements

The protection system design must comply with the reliability requirements listed in 1-09-ACS-01 Protection System – Digital.

## 5.7. Testing and validation requirements

Each secondary system device must comply with the requirement listed in 1-09-FR-36 Equipment Hardware and Software.

## 6. SAP data capture requirements

The following information on each protection devices is required to be captured in SAP or relevant software database:

- (a) Installed location;
- (b) Functional location identifier;
- (c) Description text;
- (d) Make/manufacturer;
- (e) Model number;
- (f) Manufacturer part number;
- (g) Manufacturer serial number;
- (h) Acquisition date;
- (i) Start-up date; and
- (j) ElectraNet's barcode/inventory number.

## 7. Setting requirements for protection systems

### 7.1. Short circuit calculations

The section provides a summary of some of the terminology used in the calculation of short circuit currents, equipment ratings and duties imposed by various types of faults. The terminology used is consistent with the terminology used in IEC 60909.

#### 7.1.1. Three phase faults

Three phase faults short circuit all three phase conductors while the network electrically balanced and may or may not include a connection to earth. A balanced three phase fault will not involve any current flowing in the earth conductor even if the fault is connected to earth.

#### 7.1.2. Phase to earth faults

Single phase faults involve a short circuit between one phase conductor and earth. The network becomes electrically unbalanced during these faults and calculation methods make use of symmetrical components to represent the unbalanced network. In ElectraNet's 330 kV, 275 kV and 132 kV networks, mainly due to the transformer winding and earthing arrangements, a single phase to earth fault results in a higher current in the faulted phase than would flow in each of the phases for a balanced three phase fault at the same location.

### 7.1.3. Phase to phase faults

Phase to Phase faults involve a short circuit between two phase conductors. The network becomes electrically unbalanced during these faults and calculation methods make use of symmetrical components to represent the unbalanced network. In ElectraNet's 330 kV, 275 kV and 132 kV networks, principally due to homogeneity, a phase-to-phase fault results in approximately 87% of the current in the faulted phases than would flow in each of the phases for a balanced three phase fault at the same location.

### 7.1.4. Phase to phase to earth faults

Phase to phase to earth, sometimes referred to double line to ground faults, involve a short circuit between two phase conductors and earth. As per the currents associated with phase-to-phase faults, the faulted currents maintain their pre-fault phase angles of 120 degree. However, unlike the phase-to-phase fault, phase to phase to earth faults involve a significant zero sequence current.

### 7.1.5. X/R ratio

The short circuit current is made up of an AC component (with a relatively slow decay rate) and a DC component (with a faster decay rate). These combine into a complex waveform which represents the worst-case asymmetry. The DC component decays exponentially according to a time constant which is a function of the X/R ratio, higher X/R ratios result in a slower DC decay. The X/R ratio is the ratio of reactance to resistance in the path of the current supplying the fault.

### 7.1.6. DC component

The DC component of short circuit current is calculated on the basis that full asymmetry occurs on the faulted phases involved in a short circuit fault. The DC component must be determined using the variable X/R ratio. An initial X/R ratio is used to determine the peak-make current, and a break X/R ratio is used to determine the peak break current.

*Informative: This method is sometimes referred to as the equivalent frequency method or Method c) in IEC 60909.*

### 7.1.7. Initial peak current

The initial, largest peak current occurs around 10ms after fault inception after which both the AC and DC components decay. Initial Peak Current is often termed Peak Make current as it is the short circuit current that switchgear must be able to close onto if they energise a fault. Initial Peak Current should be used in current transformer dimensioning calculations. Refer to Figure 1 Short circuit current waveform.

### 7.1.8. RMS break current

The RMS is the value of the symmetrical AC component of the short circuit current at the time the circuit breaker contacts separate. The RMS break current does not include the effect of the DC component of the short circuit current.

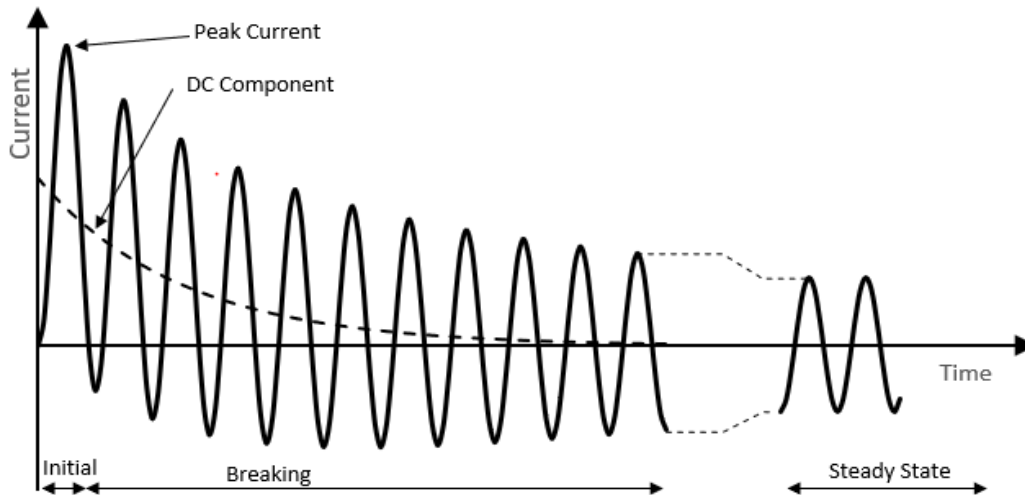
### 7.1.9. DC break current

The DC break current is the value of the DC component of the short-circuit current at the time the circuit breaker contacts open.

### 7.1.10. Peak break current

The peak break current is the highest instantaneous short circuit current that the circuit breaker is required to break and includes the decaying AC and DC components.

Figure 1 Short circuit current waveform



## 7.2. Current transformer ratio selection

CT ratios for use in protection systems, must be selected in accordance with the following criteria:

- (a) The CT remains in the unsaturated region of operation during internal and external faults for a sufficient duration to guarantee correct operation of the protection system. In all instances the ratio must be selected to ensure waveform distortion does not occur under the conditions of maximum symmetrical fault current;

*Informative: The preferred methodology for determining current transformer adequacy is in accordance with the methodology described in IEEE C37.110.*

- (b) The current rating of the primary system, including any connected bus, is not constrained by the thermal rating of the secondary circuits or associated protection settings; and

*Informative: ADM systems have a minimum continuous thermal withstand of  $3 \times I_N$  and a minimum short term, 20 min rating of  $4 \times I_N$ .*

- (c) The ratio of the available fault current and the protection system's operate current must align with the values specified within this document.

*Informative: The ratio of available fault current to protection system operate current was historically known as PSM.*

*Informative: For circuit breaker failure protection sensitivity, consideration must be given to the distribution of the fault current.*

## 7.3. Protection setting groups

Feeder protection setting groups must be configured as follows:

- (a) Setting Group 1 is the normal, service setting group which must be applied under power system normal conditions;

- (b) Setting Group 2 is a contingency setting group which may be applied under certain power system abnormal conditions such as protection signalling communications failures. Setting Group 2 should be configured so that the local relay provides full protection coverage of the protected circuit;
- (c) Setting Group 3 is a contingency setting group generally applied for commissioning activities. Setting Group 3 should be configured with an instantaneous overcurrent element set above the circuits maximum load; and
- (d) Setting Group 4 is a contingency setting group reserved for special applications. When no such applications are specified within the contract-specific documentation Setting Group 4 must be configured identical to Setting Group 1.

## 7.4. Feeder protection systems

### 7.4.1. Current differential protection schemes

The settings applied to current differential protection schemes must satisfy the requirements below. For Asset Design Manual Applications, the settings must also be determined in accordance with the relevant Setting Guidance Document.

- (a) The ratio of the minimum fault current available at the remote end of the protected feeder and the protection scheme's operate current must be greater than 2;
- (b) The protection scheme must operate for all types of faults occurring within the length of the protected feeder and for phase to earth faults with resistances up to and including 100  $\Omega$  (Primary);
- (c) The protection scheme must be set so it does not erroneously operate due to effects of transient or steady state circuit charging current; and
- (d) The protection scheme must be set so it does not erroneously operate through the effects of current transformer saturation.

**Table 1: Current differential protection scheme setting requirements**

Function	Setting	Notes
Operate current.	Minimum $\geq$ 250% of the protected feeder's steady state charging current. and; Minimum $\geq$ 20% of current transformer ratio. and; Maximum $<$ 50% of the fault current contribution from the protected feeder to a fault occurring at the remote end of the protected feeder.	The proposed setting should account for current transformer errors and protection signalling asymmetry. Where the protected feeder is equipped with line end reactors, the feeder charging current must be the calculated using the uncompensated parameters.
Operate delay	0 s	Must be set to trip instantaneously with no intentional delay in normal circumstances.

Function	Setting	Notes
Bias slope 1	Minimum $\geq 10\%$ . and; Maximum $\leq 50\%$ .	This setting defines the ratio of differential current to restraint current above which the protection would operate for values of restraint current from zero to the slope base point. The setting is determined by the accuracy limiting factors of the current transformers. For matched, Class PX current transformers the minimum setting may be applied.
Slope Base point	Minimum $\geq 150\%$ of the protected feeder's maximum loading. and; Maximum $< 90\%$ of the current at which current transformer saturation begins.	Setting defines the end of Bias Slope 1 and the transition to Bias Slope 2. In instances where a setting cannot be reconciled to satisfy both criteria, the maximum setting requirement takes precedence.
Bias slope 2	Minimum $\geq 50\%$ . and; Maximum $< 150\%$ .	Setting defines the ratio of differential current to restraint current above which the protection would operate for values of restraint current above the slope base point. It should be set to ensure stability under heavy through fault currents that could lead to current transformer saturation.

#### 7.4.2. Distance protection schemes

The settings applied to distance protection schemes must satisfy the requirements below.

- Maximum performance is achieved for SIR less than 2. Under no circumstances should the SIR be greater than 30;
- The ratio of the minimum fault current available at the remote end of the protected feeder and the operate current of any overcurrent elements must be greater than 2;
- The protection scheme must operate for all types of faults occurring within the length of the protected feeder and for phase to earth faults with resistances up to and including 100  $\Omega$  (Primary);
- The protection scheme must be set so it does not erroneously operate due to effects of load encroachment; and
- The protection scheme must be set so it does not erroneously operate through the effects of instrument transformer saturation.

*Informative: For applications where reach settings would limit the feeder's loadability it is permissible to use load blinders or load encroachment elements.*



**Table 2: Distance protection setting requirements for two terminal feeder applications**

Function	Setting	Notes
Operating characteristic	Phase Faults = Directional MHO or Directional Quadrilateral Earth Faults = Directional Quadrilateral.	The preferred characteristics are Directional MHO for phase faults and directional quadrilateral for earth faults.
Characteristic angle	$\tan^{-1}(X/R)$	Same as the angle of the protected circuit.
Residual compensation factor	$(Z_0 - Z_1) / 3Z_1$ .	Compensate relay reach for zero sequence impedance.
Phase fault resistive reach	Minimum > $R_L + R_F \Omega/\text{phase}$ Where; $R_L$ = The resistance of the protected line to the reach point; $R_F$ = Fault arc resistance / phase for phase to phase faults. Maximum < The maximum transmission line loading. and; Maximum < Relay manufacturers recommended limits; and Maximum < Minimum load impedance / 1.3 The safety margin of 1.3 must be applied to the maximum transmission line loading to account for reduced voltages.	$R_F$ must be calculated using van Warrington's expression: $R_F = \frac{28700 * L}{I^{1.4}}$ Where; $L$ = The length of the arc is equal to the distance between the phase conductors. $I$ = The fault current for a phase-to-phase fault at the open line end under minimum fault conditions.

Function	Setting	Notes
Earth fault resistive reach	<p>Minimum &gt; The maximum phase to ground fault arc resistance and tower footing resistance.</p> <p>And;</p> <p>Maximum &lt; Relay manufacturers recommended limits; and</p> <p>Maximum &lt; Minimum load impedance / 1.3</p> <p>The safety margin of 1.3 must be applied to the maximum transmission line loading to account for reduced voltages.</p>	<p>The resistive reach setting should account for the following:</p> <ul style="list-style-type: none"> <li>(a) The resistance of the protected line;</li> <li>(b) Fault resistance;</li> <li>(c) Resistance of the earth path;</li> <li>(d) Tower footing resistance; and</li> <li>(e) Ground contact resistance.</li> </ul> <p>ElectraNet’s maximum tower footing design resistance is 10 Ω. Historical measurements have revealed measurements that greatly exceed this value. However, as earth wires on the majority of ElectraNet’s transmission lines are bonded to each tower along route, the actual fault resistance for a fault involving a tower flashover is much reduced. Where actual measurement data is unavailable a maximum tower footing resistance of 40 Ω should be assumed.</p> <ul style="list-style-type: none"> <li>(a) The resistive reach must be set in accordance with the relay manufacturer’s recommendations with respect to:                     <ul style="list-style-type: none"> <li>The maximum ratio of resistive reach setting to reactive reach setting; or</li> </ul> </li> <li>(b) The maximum ratio of resistive reach setting to earth loop impedance reach setting.</li> </ul> <p>If no manufacturer’s guidance is provided, the ratio of resistive to reactive reach must not exceed 3.5.</p>
Zone 1 reactive reach at line angle	<p>Minimum &gt; 70% of the protected feeder length.</p> <p>and;</p> <p>Maximum &lt; 80% of the protected feeder length.</p>	<p>For circuits protected by double current differential protection systems protection with signalling propagation delays exceeding 20ms Zone 1 may require enabling to accelerate local fault clearance.</p> <p>The maximum setting Is preferred; however, this may need to be reduced if mutual coupling with an adjacent feeder causes the protection to overreach for earth faults.</p>

Function	Setting	Notes
Zone 1 operate delay timer	0 s	Must be set to trip instantaneously with no intentional delay in normal circumstances.
Zone 2 reactive reach at line angle	Minimum > 120% of the protected feeder length. and; Maximum < 150% of the protected feeder length.	The maximum setting is preferred; however, this may need to be reduced to avoid: (c) Overlapping the Zone 1 protection of remote feeders; (d) Reaching through transformers into the distribution network, other Transmission Network User facilities or tertiary connected equipment; and (e) Encroachment into minimum load impedance (Refer to Zone 3 Setting) The setting should also consider remote infeed and / or mutual coupling with an parallel feeder.
Zone 2 operate delay timer	Minimum > $T_{CBF} + T_{Z1DO} + T_{MARGIN}$ . where; $T_{CBF}$ = Circuit breaker failure clearance time. $T_{Z1DO}$ = Zone 1 element reset time. $T_{MARGIN}$ = Safety Margin ( $20\% \times T_{CBF} + T_{Z1DO}$ ) and; Maximum < Operation time of any upstream protection that will operate for faults beyond the Zone 1 reach.	The delay setting must achieve selectivity with any upstream protection that sees beyond the Zone 1 reach. The delay setting must also achieve selectivity with any downstream protection that will operate for faults within the Zone 2 reach.
Reverse facing blocking zone reach	$(RZ_2 - Z_L) \times 1.2$ . where; $RZ_2$ = The reach of the remote Zone 2 relay. $Z_L$ = The impedance of the protected feeder.	The reverse facing blocking zone reach is calculated to overlap the forward-facing remote Zone 2 reach by 20%.
Reverse facing blocking zone delay timer	0 s	Must be set to operate instantaneously with no intentional delay in normal circumstances.

Function	Setting	Notes
Blocking delay timer	<p>Minimum &gt; <math>T_{CH} + T_{ZRMAX} - T_{Z2MIN} + T_{MARGIN}</math>.</p> <p>and;</p> <p>Maximum &lt; The longest delay that will still allow the requisite fault clearance time to be met.</p> <p>Where;</p> <p><math>T_{CH}</math> = Communications Channel Delay.</p> <p><math>T_{ZRMAX}</math> = Reverse facing blocking element maximum operate time.</p> <p><math>T_{Z2MIN}</math> = Zone 2 element minimum operate time.</p> <p><math>T_{MARGIN}</math> = Safety Margin (20% of total time)</p>	<p>Assuming a Reverse Facing Blocking Zone maximum operate time of 30 ms and a Zone 2 minimum operate time of 15 ms, the setting for the Blocking Delay Timer is calculated from 1.2 (<math>T_{CH}+15</math>).</p>
Zone 3 reactive reach at line angle	<p>Minimum &gt; 120% of the protected feeder plus the downstream feeder length.</p> <p>and:</p> <p>Maximum &lt; Minimum load impedance / 1.3</p> <p>The safety margin of 1.3 must be applied to the maximum transmission line loading to account for reduced voltages and load angles.</p>	<p>Zone 3 is applied to provide remote backup for the failure of downstream equipment, it is only required for any circuit breakers at a remote substation without any of the following items:</p> <ul style="list-style-type: none"> <li>(f) Redundant primary protection systems;</li> <li>(g) Redundant trip systems;</li> <li>(h) Redundant DC supplies; or</li> <li>(i) In substations with dead zones between current transformers and circuit breakers, redundant circuit breaker failure protection.</li> </ul>
Zone 3 operate delay timer	<p>Minimum &gt; <math>T_{Z2} + T_{CB} + T_{Z2DO} + T_{MARGIN}</math>.</p> <p>where;</p> <p><math>T_{Z2}</math> = Zone 2 Operate Delay Timer.</p> <p><math>T_{CB}</math> = Circuit breaker opening time including arcing time.</p> <p><math>T_{Z2DO}</math> = Zone 2 element reset time.</p> <p><math>T_{MARGIN}</math> = Safety Margin (20% x <math>T_{Z2} + T_{CB} + T_{Z2DO}</math>)</p> <p>and;</p> <p>Maximum time delay should prevent damage to non-faulted equipment that is subjected to fault current.</p>	<p>The delay setting must achieve selectivity with any upstream protection that sees beyond the Zone 2 reach and any downstream protection that will operate for faults within the Zone 3 reach.</p>

Function	Setting	Notes
Switch onto fault protection	DT Overcurrent set to instantaneously operate for phase to earth faults at the remote end of the line. The function must be armed by the de-energisation of the protected feeder and must remain active for 0.2s following energisation of the protected feeder. or; Instantaneous overreaching distance protection zone that is armed by the de-energisation of the protected feeder and must remain active for 0.2s following energisation of the protected feeder.	Settings should consider load pickup and / or transformer magnetising inrush current.

### 7.4.3. Transmission overload protection

Feeder overload protection must be provided for any transmission line that may be operated beyond its maximum emergency rating duration.

**Table 3: Protection setting requirements for transmission overload protection**

Function	Setting	Notes
Operate current	$(1.15 \times \text{TLMER}) / (R_{DR})$ where; TLMER = Transmission line maximum emergency rating. $R_{DR}$ = Relay Pickup to Drop Out Ratio	Feeder overload protection must not constrain the maximum emergency rating of the transmission line under any foreseeable circumstances.
Operate time	Minimum > Achieve selectivity with any special protection scheme implemented to reduce the transmission line loading. and; Maximum < Prevent conductor's maximum design temperature from being exceeded.	-

### 7.4.4. Stub bus protection

In breaker and a half or ring bus substations it is common practice, during feeder outages, to return the circuit breakers to service thus providing increased security. Under these conditions the feeder protection systems are required to provide the protection systems for the energised elements of the circuit. Where current differential or distance functions cannot provide stub bus protection a summated overcurrent protection must be applied and set in accordance with Table 4.

**Table 4: Protection setting requirements for stub bus overcurrent protection**

Function	Setting	Notes
Operate current	Minimum > 150% of the protected feeder's maximum loading. and; Maximum < 80% of the minimum bus fault level with the contribution from the remote end of the protected feeder discounted.	The maximum setting is preferred.
Operate delay	40ms for systems > 132 kV. and; 100ms for systems < 132 kV.	Consideration must be given to achieving the clearance times specified within the National Electricity Rules.

### 7.4.5. Directional earth fault protection

Directional Earth Fault Protection is provided to detect high resistance faults that are not able to be detected by distance protection.

**Table 5: Protection setting requirements for feeder directional earth fault protection**

Function	Setting	Notes
Forward element operate current	20% of current transformer ratio. and; 200% of reverse blocking element operate current.	Consideration must be given to system unbalance and current transformer errors.
Reverse element operate current	10% of the current transformer ratio. and; 50% of the forward element's operate current.	Settings are applied to ensure the reverse facing element takes precedence over the forward-facing element.
Operate delay	0.15 s	Consideration must be given to securing Directional Earth Fault Protection from the effects of single pole auto-reclose.

## 7.5. Power transformer protection systems

The settings applied to power transformer protection systems must satisfy the requirements below. For Asset Design Manual Applications, the settings must also be determined in accordance with the relevant Setting Guidance Document.

- The ratio of the minimum fault current available and the biased differential protection's operate current must be greater than 3;
- The protection system must operate for all types of faults occurring within the protected transformer and its associated connections and must remain stable for all faults occurring beyond the protected transformer and its associated connections;
- The protection system must be set so it does not erroneously operate due to transformer energisation or loading; and

(d) The protection system must be set so it does not erroneously operate through the effects of instrument transformer saturation.

### 7.5.1. Power transformer biased differential protection

Table 6: Power transformer biased differential protection setting requirements

Function	Setting	Notes
Biased differential protection operate current (minimum pickup region)	<p>Minimum &gt; 15% of the protected transformer's rated current.</p> <p>and;</p> <p>Minimum &gt; 10% of current transformer ratio.</p> <p>and;</p> <p>Maximum &lt; 50% of the protected transformer's rated current.</p>	<p>Setting must be selected based on the amount of differential current expected under normal operate conditions including:</p> <ul style="list-style-type: none"> <li>(j) Transformer magnetisation current;</li> <li>(k) Current transformer error;</li> <li>(l) Relay measurement error; and</li> <li>(m) Auxiliary load connected within the protected zone;</li> </ul> <p>A setting closer to the minimum is preferred.</p> <p>The setting should be selected to not operate for faults on the low side of auxiliary transformers.</p>
Operate delay	0 s	<p>Must be set to trip instantaneously with no intentional delay in normal circumstances. The instantaneous setting is selected subject to the protection operation being restrained by harmonics or blocked by second harmonic.</p>
Slope 1	<p>The percentage of differential current resulting from the effects of the tap changer at maximum tap position.</p> <p>and;</p> <p>The percentage of differential current resulting from the effects of current transformer errors and relay measurement errors.</p>	<p>Setting defines the ratio of differential to restraint current from zero to Base point 1. The setting should be selected to;</p> <ul style="list-style-type: none"> <li>(n) Compensate for measurement errors under maximum loading conditions; and</li> <li>(o) Compensate for tap changer effects under maximum loading conditions;</li> </ul>
Slope 1 base point	30% of the transformer's maximum loading including cyclic loading capability.	Setting defines the end of the minimum pickup region and the transition to Slope 1.
Slope 2	<p>Minimum &gt; 60%.</p> <p>and;</p> <p>Maximum &lt; 80%.</p>	Selected based on current transformer performance. For matched, Class PX current transformers the minimum setting may be applied.

Function	Setting	Notes
Slope 2 base point	Minimum > 250% of the transformers maximum loading. and; Maximum < 90% of the current at which current transformer saturation begins.	In instances where a setting cannot be reconciled to satisfy both criteria, the maximum setting requirement takes precedence. Slope 2 base point defines the transition from Slope 1 to Slope 2.
Unrestrained differential protection operate current	Minimum > 150% of the fault current through the transformer for a three phase low side terminal fault; and; Maximum < 50% of the current supplied from the high side to a of the phase to phase fault on the high side terminals.	In instances here a setting cannot be reconciled between the minimum and maximum criteria, the minimum setting requirement must take precedence.
Unrestrained differential protection operate delay	0 s	Must be set to trip instantaneously with no intentional delay in normal circumstances.

### 7.5.2. Power transformer restricted earth fault protection

Power transformer restricted earth fault protection must be applied to any non-effectively earthed primary or secondary winding. The protection is applied to maximise the earth fault protection coverage for the non-effectively earthed winding.

**Table 7: Protection setting requirements for power transformer restricted earth fault protection**

Function	Setting	Notes
Operate current	Minimum > 15% of maximum phase to ground fault level. and; Maximum < 50% of minimum phase to ground fault level	-
Operate delay	0 s	Must be set to trip instantaneously with no intentional delay in normal circumstances.

### 7.5.3. Power transformer unrestricted earth fault protection

Power transformer unrestricted earth fault protection must be applied to any non-effectively earthed primary or secondary winding where the differential protection cannot achieve the desired sensitivity. The protection is applied as a backup to the restricted earth fault protection the earth fault protection coverage for the non-effectively earthed winding.



**Table 8: Protection setting requirements for power transformer unrestricted earth fault protection**

Function	Setting	Notes
Operate current	Minimum > 15% of the maximum phase to ground fault level. and; Maximum < 50% of the minimum phase to ground fault level	-
Characteristic	IEC 60255 DT, 30 s	Must be set to selectively operate after downstream protection and to prevent thermal damage to the neutral earthing resistor.

#### 7.5.4. Power transformer high side overcurrent protection

Power transformer high side overcurrent protection must be provided as a backup to the main differential protection. To ensure selectivity under all conditions the protection must be set to operate for a solid three phase fault on the low side bus in 1 s.

**Table 9: Protection setting requirements for high side overcurrent protection**

Function	Setting	Notes
Operate current	Minimum > $(1.15 \times TFMR_{LTECL}) / (TTR \times R_{DR})$ where; $TFMR_{LTECL}$ = Transformer Maximum Emergency Loading. $TTR$ = Tap Changer Ratio. $R_{DR}$ = Relay Pickup to Drop Out Ratio. $T_{Z2DO}$ = Zone 2 element reset time.	The setting should not constrain the transformer's maximum emergency rating under any tap position. The setting should grade with downstream protection under single transformer conditions.
Characteristic	IEC 60255 Standard (Normal) Inverse.	The characteristic and associated time multiplier must be applied to prevent plant damage.
Time multiplier	Minimum = Set to achieve an operate time of 1 s for a three-phase fault on the transformer low side bushings with zero source impedance. and; Maximum = Set to achieve an operate time to prevent damage to non-faulted equipment that is subjected to fault current, with zero source impedance.	The delay setting must achieve selectivity with any downstream backup protection for faults supplied from the high side. The delay setting must achieve selectivity with any upstream backup protection for faults supplied from the low side. The delay setting must achieve selectivity with any protection set to operate for tertiary faults supplied from the high side.

### 7.5.5. Power transformer overload protection

Current based transformer overload protection must be applied to any power transformers that are:

- (a) Used to provide a connection to the distribution network;
- (b) Used to provide a connection to a Transmission Network User; or
- (c) May be operated beyond their nameplate capacity.

**Table 10: Protection setting requirements for power transformer overload protection**

Function	Setting	Notes
Stage 1 operate current	$(1.1 \times \text{TFMR}_{\text{LTECL}}) / (R_{\text{DR}})$ where; TFMR <sub>LTECL</sub> = Transformer Maximum Emergency Loading R <sub>DR</sub> = Relay Pickup to Drop Out Ratio	The setting should not constrain the transformer's maximum emergency rating under any tap position.
Characteristic	IEC 60255 DT, 600 s	-
Stage 2 operate current	$(1.15 \times \text{TFMR}_{\text{LTECL}}) / (R_{\text{DR}})$ where; TFMR <sub>LTECL</sub> = Transformer Maximum Emergency Loading R <sub>DR</sub> = Relay Pickup to Drop Out Ratio	The setting should not constrain the transformer's maximum emergency rating under any tap position.
Characteristic	IEC 60255 DT, 15 s	-

### 7.6. Busbar protection systems

The settings applied to busbar protection systems must satisfy the requirements below. For Asset Design Manual Applications, the settings must also be determined in accordance with the relevant Setting Guidance Document.

- (a) The ratio of the minimum fault current available and the protection scheme's operate current must be greater than 2;
- (b) The protection system must operate for all types of faults occurring within the protected bus and must remain stable for all faults occurring beyond the protected bus;
- (c) The protection scheme must be set so it does not erroneously operate due to bus energisation or loading; and
- (d) The protection scheme must be set so it does not erroneously operate through the effects of instrument transformer saturation.

## 7.6.1. Biased differential buszone protection

Table 11: Setting requirements for biased differential buszone protection

Function	Setting	Notes
Operate current (minimum pickup region)	Minimum > 10% of the rated current of the protected bus. and; Minimum > 10% of current transformer ratio. and; Maximum < 50% of the rated current of the protected bus. and; Maximum < 50% of the fault contribution from the weakest infeed.	Setting must be selected based on the amount of differential current expected under normal operate conditions including: (p) Current transformer error; (q) Relay measurement error; and (r) Auxiliary load connected within the protected zone  A setting closer to the minimum is preferred.
Operate delay	0 s	Must be set to trip instantaneously with no intentional delay in normal circumstances.
Slope 1	The percentage of differential current resulting from the effects of current transformer errors and relay measurement errors.	Setting defines the ratio of differential to restraint current from zero to Base point 1. The setting should be selected to; (s) Compensate for measurement errors under maximum loading conditions.
Slope 1 base point	30% of the bus maximum loading, including emergency loading capability.	Setting defines the end of the main pickup region and the transition to Slope 1.
Slope 2	Minimum > 60% and; Maximum < 80%	Selected based on current transformer performance. For matched, Class PX current transformers the minimum setting may be applied.
Slope 2 base point	Minimum > 250% of the bus maximum loading. and; Maximum < 90% of the current at which current transformer saturation begins.	In instances where a setting cannot be reconciled to satisfy both criteria, the maximum setting requirement takes precedence. Slope 2 base point defines the transition from Slope 1 to Slope 2.

### 7.6.2. High impedance differential buszone protection

Table 12: Setting requirements for high impedance buszone protection

Function	Setting	Notes
Operate current	Minimum > 30% of the rated current. of the protected bus. and; Minimum > 10% of current transformer ratio. and; Maximum < 50% of the rated current of the protected bus. and; Maximum < 50% of the fault contribution from the weakest infeed.	The operate current refers to the primary operate current (POC) of the scheme including the magnetisation current of all connected current transformers, shunt resistors, protection and supervision relays. POC is calculated from; $I_S \times (CTR) + n \times I_{es}$ where; $I_S$ = Relay operating current at setting voltage. CTR = Current transformer ratio. n = Number of parallel connected current transformer. $I_{es}$ = Current transformer excitation current at setting voltage.
Operate delay	0 s	Must be set to trip instantaneously with no intentional delay in normal circumstances.
Stability voltage	$= I_{FMAX} \times CTR \times (R_{CT} + 2R_{RL} + R_R)$ . where; $I_{FMAX}$ = Maximum Fault Level. CTR = Current Transformer Ratio. $R_{CT}$ = Current Transformer Resistance. $2R_{RL}$ = 2 x Resistance of the connection between the relay and the electrically furthest current transformer. $R_R$ = Resistance of the Relay.	The preferred value of $I_{FMAX}$ is the switchgear's short term (1s) rating.
Setting voltage	Minimum > Stability Voltage and; Maximum < $0.5 \times V_K$ . where; $V_K$ = Current transformer knee-point voltage.	-
Resistance of stabilising resistor	$= (V_S - V_R) / I_S$ . Where; $V_S$ = Setting Voltage. $V_R$ = Relay burden expressed in voltage. $I_S$ = Relay operating current.	Stabilising resistor will be required for applications where the relay's setting voltage does not meet the required stability setting voltage. The stabilising resistor is connected in series with the relay to increase the relay setting. Stabilising relays are normally only required for relays calibrated in current.

Function	Setting	Notes
Stabilising resistor continuous power rating	$= (I_{CON})^2 \times R_S$ where; $I_{CON}$ = Continuous Resistor Current (Operating Current of Relay). $R_S$ = Resistance of Stabilising Resistor.	-
Peak voltage developed by current transformers ( $V_p$ )	$2\sqrt{2}\sqrt{V_K(V_F - V_K)}$ where; $V_K$ = Current transformer kneepoint voltage. $V_F$ = Prospective voltage assuming no saturation.	If the peak voltage developed exceeds the insulation rating of the circuit, typically 3 kV, a suitably rated non-linear resistor must be connected in parallel with the relay.

### 7.7. Circuit breaker failure protection

The settings applied to circuit breaker failure protection systems must satisfy the requirements below. For Asset Design Manual Applications, the settings must also be determined in accordance with the relevant Setting Guidance Document.

- (a) The operate current of current checked circuit breaker failure protection systems must be set to reliably operate for all faults detected by the primary protection system;
- (b) Current checked circuit breaker failure protection system’s target fault clearance time for voltage systems equal to and above 132 kV but less than 400 kV must not exceed 250 ms;
- (c) Current checked circuit breaker failure protection system’s target fault clearance time for voltage systems of less than 132 kV must be less than the protected equipment’s equipment damage time;
- (d) Current checked circuit breaker failure protection system’s time delay must include a minimum 2.5 cycle discrimination margin;
- (e) Status checked circuit breaker failure protection systems are not concerned with maintaining system stability or preventing damage to un-faulted plant and may therefore tolerate longer time delays;
- (f) The protection system must be set so it does not erroneously operate through the effects of instrument transformer saturation.

**Table 13: Setting Requirements for Current Checked Circuit Breaker Failure Protection**

Function	Setting	Notes
Operate current	10% of current transformer ratio.. and; < 30% of the expected minimum fault level.	-
Time delay	<p>Minimum &lt; <math>T_{CB} + T_{RR} + T_{DM} - T_{RP} - T_{RPA}</math> where;</p> <p><math>T_{CB}</math> = Circuit breaker trip time from trip coil energisation to arc extinction.</p> <p><math>T_{RR}</math> = The maximum reset time of the current check relay.</p> <p><math>T_{RP}</math> = The minimum pickup time of the current check relay.</p> <p><math>T_{RPA}</math> = The minimum operate time of any interposing relays which must be energised to initiate the current check element. This includes inputs, outputs and processing delays of numerical protection relays.</p> <p><math>T_{RR}</math> = The maximum reset time of the current check relay.</p> <p><math>T_{DM}</math> = Discrimination Margin (Not less than 2.5 cycles), to account for current transformer subsidence, measurement inaccuracies, timer tolerances and slow circuit breaker interruption.</p> <p>and;</p> <p>Maximum &lt; Target Fault Clearance Time.</p>	<p>Target Fault Clearance Times; 132 kV, 275 kV and 330 kV = 250 ms Less than 132 kV = The maximum duration that will prevent damage to any un-faulted plant.</p> <p><math>T_{DM}</math> must account for;</p> <ul style="list-style-type: none"> <li>(t) Current transformer subsidence;</li> <li>(u) Slow circuit breaker interruption;</li> <li>(v) Measurement inaccuracy;</li> <li>(w) Timer tolerances; and</li> <li>(x) For primary protection with integral CB Failure Protection, the time lag between the CBF timer initiation and the closure of the trip output contact.</li> </ul>

**Table 14 Setting Requirements for Status Checked Circuit Breaker Failure Protection**

Function	Setting	Notes
Time delay	500 ms.	

### 7.8. Shunt reactor protection

The settings applied to shunt reactor protection systems must satisfy the requirements below. For Asset Design Manual Applications, the settings must also be determined in accordance with the relevant Setting Guidance Document.

- (a) The ratio of the minimum fault current available and the biased differential protection’s operate current must be greater than 3;
- (b) The protection system must operate for all types of faults occurring within the protected reactor and its associated connections and must remain stable for all faults occurring beyond the protected reactor and its associated connections;

- (c) The protection system must be set so it does not erroneously operate due to shunt reactor energisation; and
- (d) The protection system must be set so it does not erroneously operate through the effects of instrument transformer saturation.

**Table 15: Setting requirements for shunt reactor biased differential protection**

Function	Setting	Notes
Operate current (minimum pickup region)	Minimum > 15% of the rated current of the shunt reactor. and; Minimum > 10% of current transformer ratio. and; Maximum < 50% of the rated current of the shunt reactor.	Setting must be selected based on the amount of differential current expected under normal operate conditions including; (y) Shunt reactor magnetisation current; (z) Current transformer error; and (aa) Relay measurement error. A setting closer to the minimum is preferred.
Operate delay	0 s	Must be set to trip instantaneously with no intentional delay in normal circumstances.
Slope 1	Flat (As per minimum pick up region)	Since there is no possibility of increased loading, a flat setting may be applied.
Slope 1 base point	150% of the shunt reactor's rated current	Setting defines the end of the minimum pick up region and the transition to Slope 1.
Slope 2	Minimum > 60% and; Maximum < 80%	Selected based on current transformer performance. For matched, Class PX current transformers the minimum setting may be applied.
Slope 2 base point	Minimum > 250% of the shunt reactor's rated current. and; Maximum < 90% of the current at which current transformer saturation begins.	In instances where a setting cannot be reconciled to satisfy both criteria, the maximum setting requirement takes precedence. Slope 2 base point defines the transition from Slope 1 to Slope 2.
Unrestrained differential protection Operate Current	Minimum > 400% of the rated current of the shunt reactor. and; Maximum < 50% of the minimum expected current for a phase-to-phase fault occurring on shunt reactor's line terminals.	-
Unrestrained differential protection operate delay	0 s	Must be set to trip instantaneously with no intentional delay in normal circumstances.

**Table 16 Setting requirements for shunt reactor backup overcurrent protection**

Function	Setting	Notes
Operate current	150% of the rated current of the shunt reactor.	-
Operate delay	1 s	-

## 7.9. Shunt capacitor bank protection

The settings applied to shunt capacitor bank protection systems must satisfy the requirements below. For Asset Design Manual Applications, the settings must also be determined in accordance with the relevant Setting Guidance Document.

- The ratio of the minimum fault current available and the capacitor bank's overcurrent protection scheme's operate current must be greater than 2;
- The protection system must operate for all types of faults occurring within the protected capacitor bank;
- The protection scheme must be set so it does not erroneously operate due to energisation of the capacitor bank; and
- The protection scheme must be set so it does not erroneously operate through the effects of instrument transformer saturation.

**Table 17 Setting Requirements for Shunt Capacitor Bank Overcurrent Protection**

Function	Setting	Notes
Instantaneous overcurrent operate current	Minimum > 400% of the capacitor bank's current at rated voltage. and; Maximum < 50% of the minimum expected current for a phase-to-phase fault occurring on shunt reactor's line terminals.	-
Instantaneous overcurrent operate delay	0 s	Must be set to trip instantaneously with no intentional delay in normal circumstances.
Time delayed overcurrent operate current	Minimum > 130% of the capacitor bank's current at rated voltage. and; Maximum < 50% of the minimum expected current for a phase-to-phase fault occurring on shunt reactor's line terminals. and; Maximum < 150% of the capacitor bank's current at rated voltage.	-
Characteristic	IEC 60255, DT, 1 s.	-



**Table 18: Setting requirements for shunt capacitor bank earth fault protection**

Function	Setting	Notes
Time delayed earth fault operate current	Minimum > 15% of the capacitor bank's current at rated voltage. and; Maximum < 50% of the expected minimum fault current. and; Maximum < 50% of the capacitor bank's current at rated voltage.	-
Time delayed earth fault operate current characteristic	IEC 60255, DT, 1 s.	-

**Table 19: Setting requirements for shunt capacitor overvoltage protection**

Function	Setting	Notes
Stage 1 operate voltage	105% of the capacitor bank's rated voltage.	-
Characteristic	IEC 60255 Definite time, 10 s.	-
Operate voltage	110% of the capacitor bank's rated voltage.	-
Characteristic	IEC 60255 Definite time, 1s.	-

**Table 20: Setting requirements for shunt capacitor bank harmonic overload protection**

Function	Setting	Notes
Stage 1 operate current	Minimum > 130% of the capacitor bank's current at rated voltage.	Stage 1 is alarm only.
Characteristic	IEC 60255, DT, 10 s.	Manufacturer's guidance should take precedence.
Stage 2 operate current	Minimum > 150% of the capacitor bank's current at rated voltage.	Stage 2 is trip.
Characteristic	IEC 60255, DT, 1 s.	Manufacturer's guidance should take precedence.
Characteristic	IEC 60255, DT, 1 s.	Manufacturer's guidance should take precedence.

**Table 21: Setting requirements for shunt capacitor bank out of balance protection (internally fused capacitors).**

Function	Setting	Notes
Stage 1 operate current	50% of the out-of-balance current which could occur for the operation of one fuse at nominal, fundamental voltage.	Stage 1 is alarm only.

Function	Setting	Notes
Characteristic	IEC 60255, DT, 10 s.	-
Stage 2 operate current	75% of the out-of-balance current which could occur for the operation of two fuses at nominal fundamental voltage.	Stage 2 is trip.
Characteristic	IEC 60255, DT, 1 s	-

**Table 22: Setting requirements for dead bus protection.**

Function	Setting	Notes
Threshold	< 50% of the capacitor current at rated voltage	-
Characteristic	IEC 60255, DT.	-
Operate delay	< 50% of the shortest auto-reclose dead time of the adjacent feeder circuit breakers	-

## 7.10. Circuit breaker control functions

The settings applied to circuit breaker control systems must satisfy the requirements below. For Asset Design Manual Applications, the settings must also be determined in accordance with the relevant Setting Guidance Document.

### 7.10.1. Automatic reclose

Automatic reclose functions must be provided for any circuit breaker that controls an overhead transmission line. The selection of single pole or three pole automatic reclose will be contract specific.

**Table 23: Setting requirements for single pole auto reclose systems**

Function	Setting	Notes
Number of reclose attempts to lockout	1	-
Fault initiation	Single phase to earth	-

Function	Setting	Notes
Dead time	<p>Minimum &gt; Delay which allows secondary arc extinction.</p> <p>and;</p> <p>Minimum &gt; Time for circuit breaker to retain full rated breaking capacity.</p> <p>and;</p> <p>Maximum &lt; Delay which does not compromise power system stability.</p>	<p>The optimal dead time must be determined through power system stability and secondary arc extinction studies.</p> <p>Delay time should be set to avoid coincidental circuit breaker operation.</p> <p>The circuit breaker selected as first to close (shortest dead time) should be assigned to the bus CB at the substation with the strongest infeed.</p> <p>For circuit breakers not selected as first to close, the dead time setting should include protection operate + transfer trip time.</p>
Reclaim time	<p>Minimum &gt; The operate time of any protection that initiates auto reclose.</p> <p>and;</p> <p>Minimum &gt; Any thermal limitation requiring cooling time between successive fault current incidents.</p>	-

**Table 24: Setting requirements for three pole auto reclose systems**

Function	Setting	Notes
Number of reclose attempts to lockout	1	-
Fault initiation	Single phase to earth	-
Reclose mode	Live Bus / Dead Line (Master) and Live Bus / Live Line (Follower)	-
Reclose priority	Master or Follower	Master should be assigned to the bus CB at the substation with the strongest infeed.
Dead time	<p>Minimum &gt; Delay which allows secondary arc extinction. Typically, 0.5 s</p> <p>and;</p> <p>Minimum &gt; Time for circuit breaker to retain full rated breaking capacity. Typically 0.3 s</p> <p>Minimum &gt; Any synchronism check qualifying period. Typically 4 s</p> <p>and;</p> <p>Maximum &lt; 10 s</p>	<p>Generally, the dominant minimum delay setting will be the synchronism check qualifying period.</p> <p>Delay time should be set to avoid coincidental circuit breaker operation.</p> <p>For circuit breakers not selected as Master, the additional dead time setting should include protection operate + transfer trip time.</p>

Function	Setting	Notes
Reclaim time	Minimum > The operate time of any protection that initiates auto reclose. and; Minimum > Any thermal limitation requiring cooling time between successive fault current incidents.	-

### 7.10.2. Synchronising

Manual close synchronising functions must be provided for all circuit breakers. Synchronising functions must also be provided for circuit breakers equipped with three pole automatic reclose facilities. Synchronising functions must be provided to permit circuit breaker closure to:

- (a) Connect parts of the already interconnected power system; and
- (b) Connect separated parts of the power system.

*Informative: Synchronising systems used to connect parts of an interconnected power system are termed synchronism check systems. Synchronising systems used to connect separated parts of a power system are termed power system synchronising systems.*

**Table 25: Setting requirements for synchronism check systems**

Function	Setting	Notes
Maximum slip speed	0.05 Hz	-
Maximum angle difference	30 degrees	-
Maximum voltage difference	12%	-
Dead volts threshold	Minimum = 15% and; Maximum = 20%	Where voltage selection schemes, involving long lengths of multicore cable, are used to derive synchronising voltage references the maximum dead volts threshold must be applied.
Live volts threshold	85%	-
Qualifying time	4 s	-

**Table 26: Setting requirements for power system synchronising systems**

Function	Setting	Notes
Maximum slip speed	0.1 Hz	-
Maximum angle difference	12°	-
Maximum voltage difference	12%	-

Function	Setting	Notes
Dead volts threshold	Minimum = 15% and; Maximum = 20%	Where voltage selection schemes, involving long lengths of multicore cable, are used to derive synchronising voltage references the maximum dead volts threshold must be applied.
Live volts threshold	85%	-
Sequence time	60 s	Initiation to reset time.

### 7.10.3. Circuit breaker pole discrepancy

Pole discrepancy tripping must be provided for all single pole operation circuit breakers.

**Table 27: Circuit breaker pole discrepancy settings for single pole operation circuit breakers used in phase segregated tripping applications**

Function	Setting	Notes
Pole discrepancy trip delay time	Minimum = 1s and; Minimum = (1.5 x ARDT) where; ARDT = Auto Reclose Dead Time	-

**Table 28 Circuit Breaker Pole Discrepancy Settings for Single Pole Operation circuit breakers used in three pole tripping applications**

Function	Setting	Notes
Pole discrepancy Delay Trip Time	0.5 s	-

### 7.10.4. Circuit breaker overload protection

Circuit breaker overload protection must be provided for all circuit breakers deployed in ring bus, BAAH or double breaker configurations. The protection must be arranged to initiate local and remote alarms.

**Table 29: Protection setting requirements for circuit breaker overload protection**

Function	Setting	Notes
Operate current	$(1.1 \times BCR) / (R_{DR})$ where; BCR = Bay continuous rating, derived from the lowest continuous rating of the equipment within the circuit breaker bay. $R_{DR}$ = Relay Pickup to Drop Out Ratio	The continuous rating of the circuit breaker bay is derived from the ratings of the circuit breaker, the maintenance isolators, the current transformer together with associated secondary systems and the interconnecting conductors.
Characteristic	IEC 60255, DT, 60 s	-

## 8. Format and content of a protection setting report

### 8.1. Format

A Protection Setting Report is required for every protection relay and must be used to calculate and record every setting within the relay. The report must be stored within ElectraNet's Intelligent Process Solutions (IPS). The report must be presented in A4, portrait, format with 2.54 cm all round margins. Page numbers must appear at the foot of each page and the title must appear at the head of each page.

The following fonts must be utilised in the report with line spacing of 1.5;

- (a) Section titles: Arial, Bold, Size 14;
- (b) Subsection titles: Arial, Bold, Size 12;
- (c) Section and subsection text: Arial, Regular, Size 11; and
- (d) Text in tables: Arial, Regular, Size 8.

Diagrams and tables must be sequentially numbered, with the diagram number and title centred above the diagram.

### 8.2. Content

Protection Setting Reports must be produced using Microsoft Office and converted to portable document format. The report must be structured with the following sections:

- (a) Title;
- (b) Document control;
- (c) Summary of settings;
- (d) Table of contents;
- (e) Introduction;
- (f) Body of report;
  - i. Power system data;
  - ii. Plant data;
  - iii. Protection relay data;
  - iv. Abridged diagram;
  - v. Current transformer suitability calculations; and
  - vi. Protection setting requirements and calculations,
- (g) Conclusions;
  - i. Compliance assessments;
  - ii. Load assessments; and
  - iii. Coordination study,
- (h) Recommendations; and
  - i. Relay setting schedule
- (i) References.

### **8.2.1. Title**

The Protection Setting Report's Title must form the document's cover page and must include the following data presented in tabular form:

- (a) Substation name and voltage level e.g., Davenport 275 kV Substation;
- (b) Protected circuit name and voltage level e.g., Mount Lock 275 kV Feeder;
- (c) Protected circuit Identity Number e.g., F1919;
- (d) Protection Set Number e.g., Set 1 Protection; and

### **8.2.2. Document control**

The Protection Setting Report's Document Control Section must include the following data, presented in a tabular form:

- (a) ElectraNet project number;
- (b) ElectraNet project title;
- (c) The report's version number;
- (d) Report author's name and organisation name;
- (e) Report reviewer's name and organisation name;
- (f) Report approver's name and organisation name;
- (g) Date of production;
- (h) Date of review; and
- (i) Date of approval.

### **8.2.3. Summary of settings**

The summary of settings must contain a list of the protection functions enabled within the protection relay, together with their operate settings and delays.

### **8.2.4. Table of contents**

The table of contents must show the sections and subsections of the report together with their corresponding page numbers. Specific items of information must be locatable from the table of contents. Sections must be numbered using the decimal point system and appear on the left of the section title, page numbers must appear on the right.

### **8.2.5. Introduction**

The introduction must comprise of three main components:

- (j) Background;
- (k) Purpose; and
- (l) Scope.

## 8.2.6. Body of report

### 8.2.6.1. Power System Data

Power system data must be obtained from ElectraNet's Asset Management Division and must be presented in tabular format.

### 8.2.6.2. Plant data

The ratings and impedance data of the protected equipment and any associated equipment involved in the calculations must be presented in tabular format.

### 8.2.6.3. Protection relay data

The protection relay data must include details of the manufacturer, relay model, firmware, and serial number.

### 8.2.6.4. Abridged diagram

The report must include an abridged diagram providing a simplistic, single line overview of the protected object, the relay and the associated current and voltage transformers and connections.

### 8.2.6.5. Current transformer suitability calculations

The current transformer suitability calculations must demonstrate the current transformer will perform satisfactorily under all power system conditions.

### 8.2.6.6. Protection setting requirements and calculations

The setting rationale, requirements and associated calculations for every protection function enabled within the protection relay must be laid out within the report. The calculations must demonstrate satisfactory operation for all fault types occurring within the zone of protection, under maximum and minimum fault level conditions. On some, complex arrangements it may be necessary to supplement the calculations using a power system analysis tool.

## 8.2.7. Conclusions

The conclusions section of the report must contain compliance assessments, load assessments and, where applicable co-ordination studies.

### 8.2.7.1. Compliance assessments

The compliance assessments must include:

- (a) Confirmation that primary protection trip times meet the requirements of the NER, with deviations stated;
- (b) Confirmation that all circuit breaker failure trip times meet the requirements of the NER, for all contiguous circuit breakers; and

### 8.2.7.2. Load assessments

The maximum loading requirements of the protected circuit and associated connections are not constrained due to:

- (a) Thermal rating limitations of the current transformer, protection relay and associated connections; or



(b) Any protection settings that would operate prior to the maximum rating of the equipment being reached.

### **8.2.7.3. Co-ordination study**

A co-ordination study may be required to demonstrate the selectivity of the protection system. This will generally only be required for some more complex protection arrangements where selectivity cannot be demonstrated through calculation. The preferred method for performing co-ordination studies is through the utilisation of a power system analysis tool.

## **8.2.8. Recommendations**

The recommendations section of the report contains the complete list of setting requirements for the protection relay in the form of a schedule that correlates to the protection relays menu structure.

### **8.2.8.1. Relay setting schedule**

The relay setting schedule contains a list of every setting within the protection relay and the applied setting. For ADM applications the Settings Guidance Document must be modified to form the relay setting schedule.

## **8.2.9. References**

The reference section of the Protection Setting Report contains the details of any supporting documentation used in the body of the report.



# Appendices

## References

### Organisations

Organisation	Description	Details
IPS-ENERGY	Australian private company that is a subsidiary of IPS SYSTEMS which is a private software company with head office in Germany.	IPS-ENERGY AUSTRALIA PACIFIC PTY LTD

### Legislation

Legislation	
NER	National Electricity Rules
SAEA	Electricity Act 1996 (SA)
TC/08	Electricity Transmission Code by the Essential Services Commission of South Australia

### Standards

Name	Title
IEC 60255	Measuring relays and protection equipment.
IEC 60050-448	International Electrotechnical Vocabulary – Power System Protection.
IEC 60909	Short Circuit Currents in Three Phase AC Systems.

### ElectraNet documents

Name	Title
1-09-ACS	Protection System – Digital
1-09-FR-02	Feeder Differential Protection
1-09-FR-03	Feeder Distance Protection
1-09-FR-04	Non-Feeder Differential Protection
1-09-FR-05	Thermal Overload Protection
1-09-FR-06	Overcurrent Protection
1-09-FR-07	Overvoltage and Loss of Voltage Protection
1-09-FR-08	Mechanical Protection
1-09-FR-09	Protection Signalling and Intertripping
1-09-FR-10	Circuit Breaker Fail
1-09-FR-13	Trip Circuit Supervision

Name	Title
1-09-FR-15	Synchronising
1-09-FR-17	Auto-reclose Switching
1-09-FR-18	Automatic Voltage Regulation
1-09-FR-26	Cubicle and Panel
1-09-FR-36	Equipment Hardware and Software
1-11-FR-27	Current Transformers

