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Modern Techniques for Protecting Busbars in HV Networks

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2 Introduction / Overview

2.1 Purpose and Scope

This report establishes criteria and requirements for designing protection systems for busbars in high voltage networks. The selection and application of different protection schemes are addressed.

This document is intended to assist the relay application engineer in the correct selection and application of busbar protection systems. It provides requirements relevant to the performance, operation, testing, and maintenance of busbar protection systems. This guide applies to all types of busbar designs.

2.2 Factors Which Determine the Need for and Principles of Busbar Protection

Today, electric power companies (utilities) worldwide, driven by deregulation and increased competition, have changed the way they operate. Power plants and lines are becoming loaded up to both thermal and stability limits. Existing power plants are expected to operate up to and beyond the end of their original design life. Corrective event-based repair replaces preventive maintenance. Considering these changes, power system protection and control face new technical and economic challenges.

Modern secondary systems play an important role in satisfying the above requirements for lower investment and operational cost without compromising system reliability.

To assure power system integrity during fault conditions, one of the most important requirements is reliable performance of power system busbar relay protection. This requirement is further emphasized by the fact that an incorrect operation of busbar protection will result in loss of all connected lines, power transformers, and generators, which may lead to a power system blackout.

Reliable performance of the busbar protection system must be preserved for both In-Zone and Out-of-Zone faults. This is a challenging task since high fault currents may exist at the substation making it difficult, or even impossible, to avoid saturation of conventional iron-cored CTs. Most busbar protection systems operate on a differential principle by comparing input and output currents. If a CT saturates, then a false differential current will be derived by the relay. Busbar protection schemes implemented in modern numerical multifunction relays are designed to tolerate substantial CT saturation, while providing high-speed operation for In-Zone faults (dependability). Relays are designed to reliably operate in the presence of distorted waveforms, or prior to CT saturation (time-to-saturation). High-speed busbar protection operation is required since bus faults may result in large fault currents endangering the entire substation due to the high dynamic forces and thermal stresses experienced. For external Out-of-Zone faults (security), the protection scheme must remain stable for all types of fault for the time needed to clear the fault. Manufacturers use different algorithms to achieve relay stability during CT saturation. While both security and dependability are important requirements for busbar protection, the preference is usual given to security.

Four key issues (reliability, operability, maintainability, and cost) need to be addressed when designing a substation and selecting a busbar configuration. At EHV/HV levels, solutions that provide a high degree of reliability can be justified. A modern busbar protection system should dynamically replicate the bus topology. It should also contain sufficient design flexibility to protect all existing bus arrangements. In general, the main requirements for busbar protection include:

Security - probability of an unnecessary protection operation for through faults (Out-of-Zone faults) is low.

Dependability - probability that the protection will not operate for a fault on the bus (In-Zone faults) is low.

Speed – high-speed operation is required to limit equipment damage, and to preserve system transient stability.

Sensitivity – the ability to detect and clear high resistance faults.

Selectivity – the ability to isolate only the faulty bus section

All these requirements are interrelated; therefore, it is not possible to satisfy one without affecting the other. The design solution should meet the requirements that correspond to the importance of the substation within the network and the layout of the substation.

Justification for a dedicated busbar protection scheme is generally based on the following factors:

- Voltage level (see Figure 2-1),
- Importance of the substation,
- Impact on network performance such as transient stability,
- Extent of equipment damage such as to GIS,
- Cost of busbar protection system (CTs, relay, and implementation)

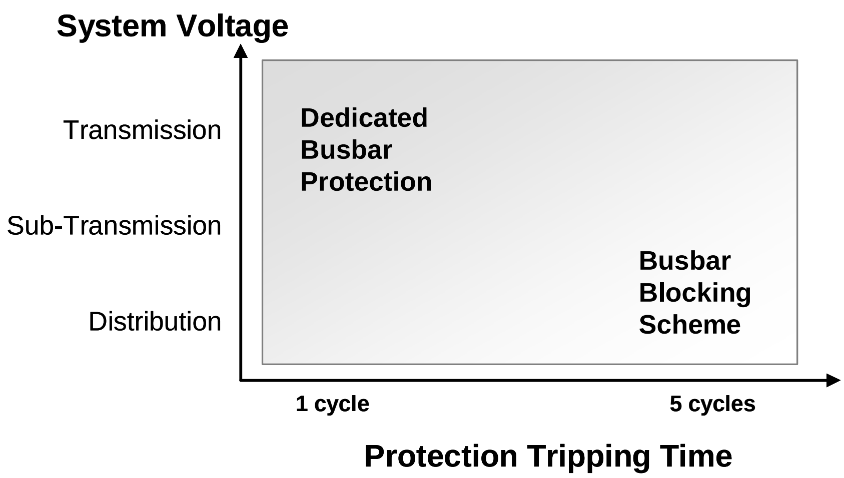


Figure 2-1 Application of Busbar Protection

The technical objective is to achieve fast protection operation to minimize fault damage. However, at lower voltage levels, the costs of fast protection may not be justified and for industrial applications, it is common to use relays that can perform busbar protection in addition to other protection functions. In this case, the busbar protection scheme will usually be designed as a busbar blocking scheme as described later in the text.

However, for applications where fast protection operation is essential and/or to segregate the impact of faults, dedicated busbar protection schemes are preferred.

Statistically, there is a low rate of In-Zone fault incidences on busbars in high voltage systems (an average of one fault per busbar per ten years). Out-of-Zone faults are much more frequent than In-Zone faults. Reliable performance of the busbar protection systems must be preserved for both fault types, In-Zone (dependability) and external faults Out-of-Zone (security). For Out-of-Zone faults, the busbar protection scheme must remain stable for all types of fault for the time needed to clear the fault. Consequences of a protection mal-operation for Out-of-Zone faults can be serious since it can result in the loss of a whole substation, even though there was no fault within the substation. Therefore, reliable protection operation is an absolute requirement.

In the past, busbar protection systems were susceptible to incorrect operation, which led to hesitation in applying busbar protection and also resulted in application of complex systems such as having many protection Zones (more than 6 Zones).

Modern busbar protection systems have achieved a high degree of reliability by implementing numerical technology with advanced algorithms, fibre-optic communications, intelligent tripping decisions, and monitoring features to prevent incorrect operation due to problems in external system components such as CT secondary wiring, wrong isolator position, and power supplies.

3 Terms and definitions (nomenclature)

back-tripping	To effect the high-speed tripping of all circuit-breakers selected to a particular busbar and to adjacent busbars
back-up protection [2]	Protection which is intended to operate when a system fault is not cleared, or abnormal condition not detected, in the required time because of failure or inability of other protection to operate or failure of the appropriate circuit breaker(s) to trip
bay [3]	The part of a substation within which the switchgear and control gear relating to a given circuit is contained
bay unit	A bay unit within a numerical busbar and breaker-failure protection is the interface between the protection and the primary system process comprising the main CTs, disconnectors and circuit-breaker and performs the associated data acquisition, pre-processing and control functions. It also provides the electrical insulation between the primary system and the internal electronics of the protection.
BBP	– see 'busbar protection'
blind spot	– see 'dead zone'
blind zone	– see 'dead zone'
breaker failure protection (USA)	– see 'circuit breaker failure protection'
burden (of an instrument transformer) [7]	The impedance of the secondary circuit
busbar [3]	A low impedance conductor to which several electric circuits can be separately connected
busbars [3]	In a substation, the busbar assembly necessary to make a common connection for several circuits
busbar blocking scheme	A busbar protection scheme utilizing non-directional and/or directional overcurrent relays or distance relays to provide a simple busbar protection at distribution substations
bus image	– see 'dynamic bus replica'
bus mimic	– see 'dynamic bus replica'
busbar protection	Protection intended to operate to initiate fault clearance on a busbar
busbar section [3]	The part of a busbar located between switching devices as circuit breakers or disconnectors put in series or between a switching device and the end of the busbar
bus coupler circuit-breaker [3]	In a substation a circuit-breaker which is located between two busbars and which permits the busbars to be coupled; it may be associated with selectors in case of more than two busbars
bus section circuit-breaker [3]	In a substation a circuit-breaker which is located between two busbar sections of the same bar and which permits two sections to be coupled
busbar section disconnector [3]	A disconnector which is connected in series between two busbar sections, in order to disconnect them from each other
bus-tie circuit-breaker	- see bus coupler and bus section circuit-breaker
CBF	– see 'circuit breaker failure protection'

central unit	The central unit within a numerical busbar and breaker-failure protection is the system manager typically used for system configuration, operating parameters, busbar replica, assignment of bays, system synchronization, communications control etc.
check zone [2]	The non-selective part of a multi-zone busbar protection generally supervising current flow at the terminals of the complete station. Note: Tripping from the busbar protection is conditional on operation of both the check and a discriminating zone.
circuit-breaker failure protection [2]	A 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
direct transfer trip	– see 'intertripping'
dead zone	On bus sections and bus couplers where current transformer(s) have only been installed on one side of the circuit breaker a protection 'blind zone' or 'blind spot' will exist between the circuit breaker and it's associated CT(s) for which faults will not be cleared.
decentralized BBP	A numerical busbar protection system in which the bay units can be located close to the switchgear with short connections to current transformers, circuit-breakers, disconnectors and other bay protection devices
discriminating zone [2]	The selective part of a multi-zone busbar protection, generally supervising current flow into and out of a single section of busbar
distributed BBP	– see 'decentralized BBP'
dynamic bus replica / bus image / bus mimic/ disconnector replica / zone selection	Utilizing built-in programmable logic the dynamic bus replica provides the capability to include and exclude currents dynamically from the differential zone without the need for external auxiliary relays. This enables the busbar protection to 'mimic' the actual busbar configuration whilst avoiding the switching of CT circuits and trip circuits
end zone protection	Applies to feeder bays when current transformers are mounted on one side of the circuit breaker only, which results in a blind zone, since BBP alone cannot clear this fault.
fault clearance [8]	The disconnection from the electrical system of a defective item, by automatic or manual operations, in order to maintain or restore supply.
fault clearance time [8]	The time interval between the occurrence of a fault and the fault clearance.
feeder bay [3]	In a substation, the bay relating to a feeder or a link to a transformer, a generator or another substation
feeder circuit breaker [3]	In a substation, a circuit breaker which is located within a feeder bay and through which a feeder can be energized
feeder disconnector [3]	A disconnector which is located in series at the end of a feeder, within a substation bay, in order to isolate the feeder from the system
high impedance differential protection [2]	Current differential protection using a current differential relay whose impedance is high compared with the impedance of the secondary circuit of the saturated current transformer
intertripping [2]	The tripping of circuit-breaker(s) by signals initiated from protection at a remote location independent of the state of the local protection
low impedance differential protection [2]	Current differential protection using a current differential relay whose impedance is not high compared with the impedance of the secondary circuit of a saturated current transformer.
main busbar [3]	In a double, (or triple) busbar substation, any busbar which is used under normal conditions

main protection [2]	Protection expected to have a high priority in initiating fault clearance or an action to terminate an abnormal condition in a power system. Note: For a given item of plant, two or more main protections may be provided.
numeric protection	A numeric protection performs analogue to digital conversion on samples of the secondary voltage and/or current signals and uses numerical methods to determine relay operation
on-load transfer	With two busbar disconnectors simultaneously closed in one feeder bay
peripheral unit	– see 'bay unit'
primary protection (USA)	see 'main protection'
protected zone	The portion of a power system protected by a given protection system or a part of that protection system. The boundary of the protected zone is defined by the position of the current transformers in order to identify the location of the fault. The position of the circuit breakers is chosen in order to facilitate the isolation of the fault.
protection system [2]	An arrangement of one or more protection equipments, and other devices intended to perform one or more specified protection functions
rated burden [7]	The value of the burden upon which the accuracy requirements of a specification are based
rating	The nominal value of an energizing quantity which appears in the designation of a relay; the nominal value usually corresponds to the CT and VT secondary ratings
redundancy	The design practice of replicating the sources of a function so that the function remains available after the failure of one or more items
sectionaliser	– see 'switched busbar circuit-breaker'
sensitivity	The minimum value of the energizing quantity(ies) required to just cause operation of a relay under specified conditions
setting	The limiting value of a 'characteristic' or 'energizing' quantity at which the relay is designed to operate under specified conditions.
stability	The quality whereby a protective system remains inoperative under all conditions other than those for which it is specifically designed to operate
static relay [8]	An electrical relay in which the designed response is developed by electronic, magnetic, optical or other components without mechanical motion.
switched busbar circuit-breaker [3]	In a substation a circuit-breaker, connected in series within a busbar between two busbar sections.
through fault current [2]	A current due to a power system fault external to that part of the section protected by the given protection and which flows through the protected section
transfer busbar [3]	A back-up busbar to which any circuit can be connected independently of its bay equipment, (circuit-breaker, instrument transformer) the control of this circuit being ensured by another specific bay, available for any circuit.
transfer tripping (USA)	– see 'intertripping'
zone selection	– see 'dynamic bus replica'

4 Fundamentals

4.1 Different busbar arrangements

Depending on the voltage level, user requirements and preferences, different busbar arrangements are used. Some typical examples are shown below.

Single busbar arrangements

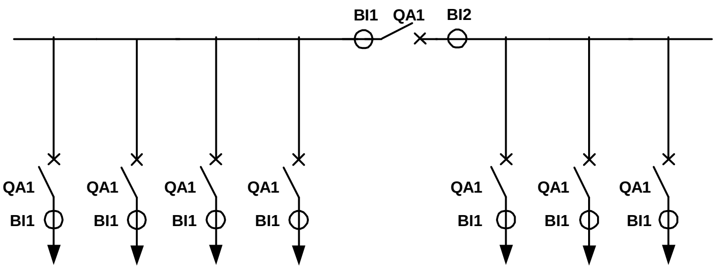


Figure 4-1 single busbar

Double busbar arrangements with two sections

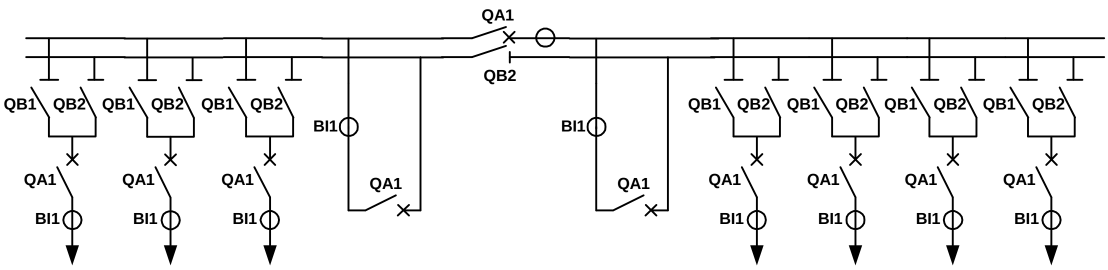


Figure 4-2 double busbar

Double busbar with transfer bus

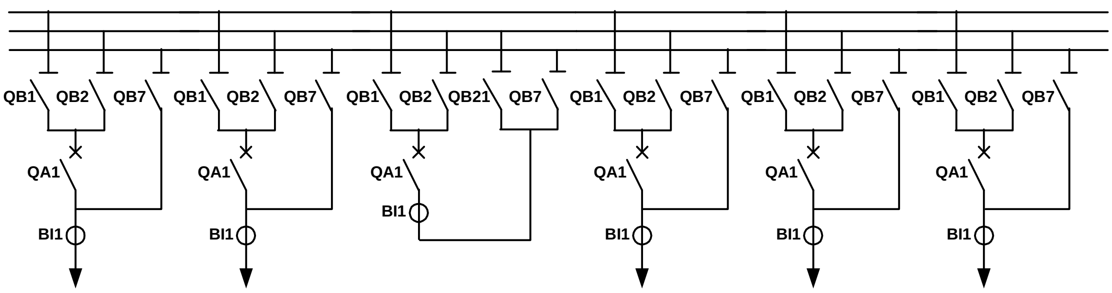


Figure 4-3 double busbar with transfer bus

Double busbar arrangements with double breakers

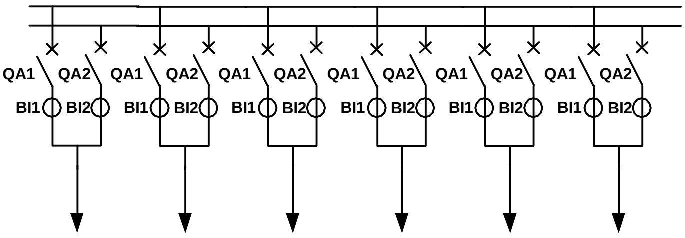


Figure 4-4 double busbar with double breakers

Triple busbar arrangements

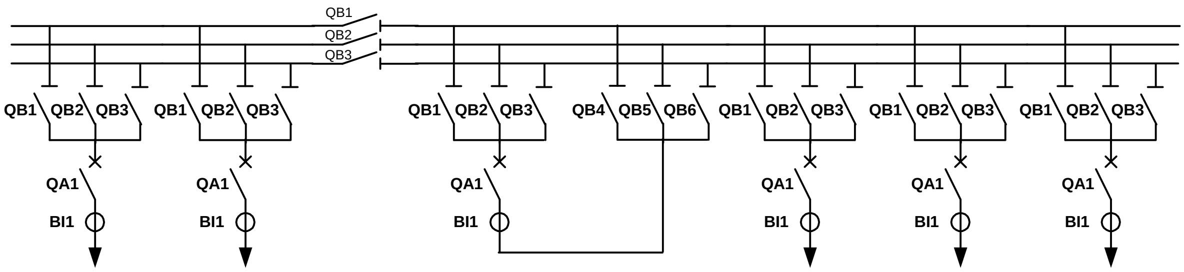


Figure 4-5 triple busbar

Breaker-and-a-half arrangements

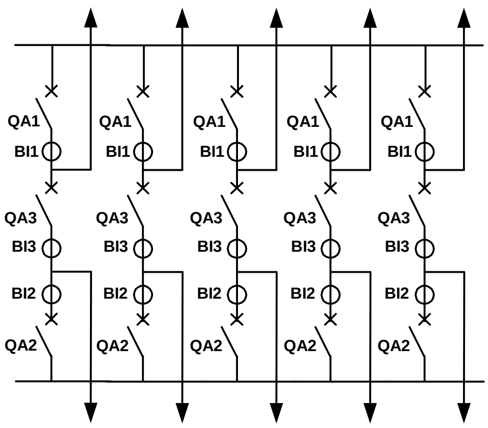


Figure 4-6 breaker-and-a-half arrangement

Ring busbar

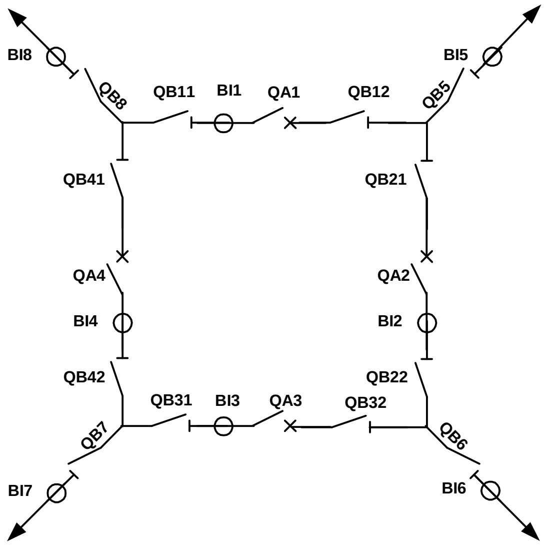


Figure 4-7 ring

Definitions of Symbols Used:

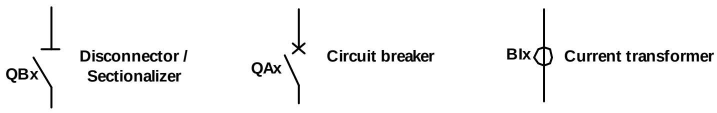


Figure 4-8 Definitions of Symbols Used:

4.2 Basic principles of busbar protection operation

Busbar protection systems protect substation busbars and associated equipment from the consequences of short-circuits and earth faults. In the early days of power system development no separate protection device was used for busbar protection. Remote end-line protections served as the main protection for busbar faults. As a result of increased network short-circuit capacity, dedicated differential relays for busbar protections have been applied to limit the damage caused by high fault currents. Today, busbar protection systems are widely used and the following protection methods are generally applied.

4.2.1 Differential protection

The protection concept for all bus differential relay schemes is based on Kirchhoff's First Law that the sum of all currents at the common point of connection, at any instant in time, is equal to zero. In particular, for bus differential protection this means that the sum of currents that flow from the source to the bus must be equal to the sum of all currents that flow from the bus to the load. If this is not satisfied, an internal fault (In-Zone fault) has occurred. However, in actual applications, bus differential relays can unintentionally operate when there is no fault on the protected bus. This may happen when faults in the power system cause high currents to flow through the protected bus causing saturation of some iron-cored CTs that provide information to the relay about the magnitude of the primary currents. Saturated CTs will provide false information, reporting smaller current magnitudes than there actually are. As a result, the relay will derive differential current that does not exist. To avoid unnecessary operation, manufacturers use different algorithms to achieve relay stability during CT saturation.

4.2.1.1 High impedance differential

High impedance differential protection systems have been in use for over 50 years. The protection system consists of CTs whose secondary windings are connected in parallel with one high impedance voltage relay. High impedance protection responds to a voltage across the relay. All CTs must be well-matched, have equal ratios, and have low secondary leakage impedance. The major disadvantage is the requirement for dedicated CT cores. When used for re-configurable buses, the switching of CT secondary currents may affect the performance of the protection and increase the cost. In addition, this solution requires voltage limiting varistors. New microprocessor-based high impedance relays operate on the same principle as traditional designs. They also provide functions such as sequence of events, disturbance recording, and communication.

For the case of an external fault causing current transformer saturation, the non-saturated current transformers will drive most of their currents through the secondary winding of the saturated current transformer. The voltage drop across the saturated current transformer secondary winding will also appear across the relay, but typically it will be relatively small. To avoid protection operation, the relay pick-up value has to be set above this false operating voltage.

In the event of an internal fault, the sum of the CT secondary currents will flow through the relay measuring element and high resistance connected in series with the relay. This will result in a steep voltage increase across the entire scheme, causing fast saturation of all current transformers. The differential relay is designed to operate under these conditions. To ensure reliable operation for internal faults, the knee-point voltage of the current transformers must be approximately two times the relay pick-up voltage. The protection sensitivity corresponds to the sum of the magnetizing currents of all parallel connected current transformers plus the relay current at the relay pick-up voltage. Often non-linear resistors are required to limit the over-voltages that are experienced during internal faults to less than 2 kV peak, which is the standard insulation level used for secondary equipment and wiring. Typically, the operating time for a high impedance differential relay is approximately 1 cycle. Detailed information about high impedance differential protection is given in Reference [23].

Note: The entire scheme, including built-in components and wiring, must be adequately maintained in order to withstand these high voltage pulses throughout the lifetime of the equipment. Otherwise, for faults within the zone of protection, any flashover in the CT secondary circuits could prevent the proper operation of the differential relay.

4.2.1.2 Low impedance differential

Modern low impedance differential protection systems employ numerical relays. The CT inputs are connected to individual channels. The relay derives differential signals by executing protection algorithms. These solutions allow the use of CTs with different ratios since CT matching is performed inside the relay. The same CT core can be used by different protection relays. In addition to the operating quantity, low impedance differential protection systems also derive a stabilizing quantity and apply a percent (biased) characteristic to ensure the stability of the scheme.

Differential current I_{diff} (operating quantity) equals the vector sum of all bay currents connected to the protection zone (Equation 1) and is represented on the y-axis as shown in Figure 4-9.

$$I_{diff} = \left| I_1 + I_2 + \cdots + I_n \right| \qquad 1$$

Stabilizing (restraint) current I_s is represented on the x-axis. Manufacturers use different methods to calculate the stabilizing current such as a “sum”, “average”, or “maximum” of the bay currents. For example, the arithmetic sum of the bay current magnitudes for all feeders connected to the protection zone is represented by Equation 2.

$$I_s = |I_1| + |I_2| + \cdots + |I_n| \qquad 2$$

The protection operating characteristic typically consists of a single-slope or dual-slopes. The gradient of slope may be settable. For overload currents and small fault currents that result in small stabilizing current a minimum pickup level Idiff> is used as shown in Figure 4-9

The operating characteristic is formed in such a way that higher fault currents require a higher operating (tripping) quantity to trip, corresponding to the gradient of the slope of the stabilizing current. The protection system continuously determines where the operating point is, based on the operating characteristic.

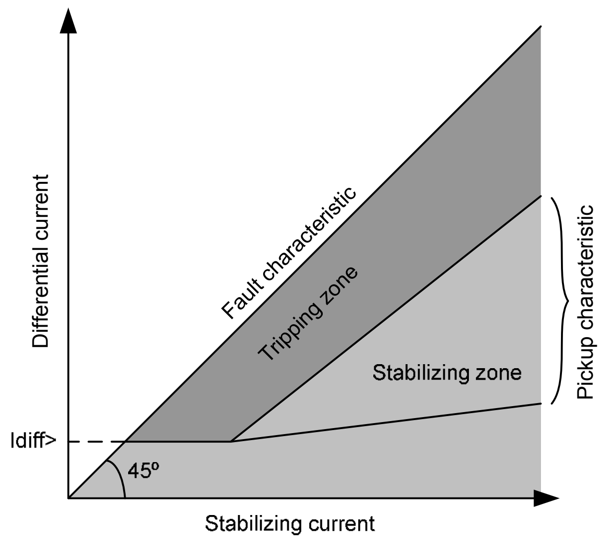


Figure 4-9 Typical BBP tripping characteristic

Modern relays, in addition to the percentage characteristic, may have implemented sophisticated algorithms to cope with severe CT saturation. Some relays are designed to make decisions before the CT saturates. For modern numerical busbar protection schemes, a time-to-saturation of 2–3 ms may be sufficient to stabilize the protection in case of external faults, which requires CTs having smaller over-dimensioning factors. Typically, operating times are one cycle or less.

Numerical relays have also implemented the station disconnector replica in the relay software. This avoids the need for moving parts. Other advantages include integrated functions such as those described in Section 12 (Modern Relay Features).

4.2.2 Busbar blocking scheme

Traditionally, faults in a distribution system busbar have been cleared with a time delay by an upstream overcurrent protection. Today, numerical overcurrent relays can be used to effectively protect distribution system busbars. This can be achieved by interconnecting the existing overcurrent relays that provide feeder protection as their primary task. These schemes are called Busbar Blocking Schemes and provide the following advantages:

- Faster busbar fault clearance compared to tripping initiated by the upstream time-graded feeder protection.
- Busbar protection requires minimal additional cost since it uses overcurrent elements already provided in the feeder protection relays.
- Fault and disturbance records can be stored.
- Blocking schemes can be easily modified to suit substation extension.

Busbar blocking schemes operate as follows. If a fault occurs on the outgoing feeder (Out-of-Zone fault), the faulty feeder overcurrent relay closes a contact to block the upstream overcurrent relay on the incoming bay and prevents its operation. However, if the fault is on the bus, the feeder overcurrent relays will not block the incoming feeder relay, allowing its operation to clear the fault.

This concept can be extended to include circuit breaker failure protection and provide proper co-ordination to isolate only the faulted busbar section. However, in practice, the scheme becomes complicated for complex station layouts and meshed power systems. Typically, such systems are mainly used in radial distribution networks.

4.2.3 Arc protection (light sensitive)

Arc protection is based on detection of light caused by flashover at the fault point. To ensure scheme reliability, the overcurrent condition on the incoming feeder is checked as an additional detection criterion. These schemes are only applicable for metal-clad switchgear.

4.2.4 Busbar splitting

Some utilities apply a so-called ‘busbar-splitting’ scheme in order to minimize the impact of a busbar fault on the power system. Such a solution is typically adopted when there is no BBP in the substation. The idea is to split the substation into individual sections by tripping all bus-section and bus-coupler circuit breakers in the station for a busbar fault. Such a scheme is typically achieved by using overcurrent or distance protection in all bus-section and bus-coupler bays. These protection relays are set to detect all faults in the vicinity of the substation. However the time delay of these protections is set between the operating time of the local Z1 distance protection and the remote end Z2 distance protection (e.g. 200ms).

Thus for an external feeder fault the Z1 distance protection will operate and clear the fault and the busbar-splitting scheme will reset without operation. For an internal busbar fault the busbar-splitting scheme will operate before the remote end Z2 distance protection. Such internal busbar faults will then be cleared by operation of the Z2 distance protections of the feeders connected to the faulted busbar section only. Thus, all feeders connected to the healthy busbar sections will remain in service. It shall be noted that sufficient time margin for resetting of remote end Z2 distance protection on feeders connected to the non-faulted bus sections shall be verified for such applications.

4.2.5 Remote end distance protection

In transmission and sub-transmission networks, distance protection is typically used as the feeder protection. Thus, if no dedicated busbar protection is available in the substation, the remote feeder end Zone 2 distance protection will provide protection for busbar faults with a time delay that of typically 250 ms to 600 ms. Since busbar faults will be cleared with a time delay, this may not be an adequate solution for busbar protection at transmission voltage levels due to network stability and equipment damage.

4.3 Power system earthing/grounding

Earthing (grounding) of the power system neutral point(s) has the following main purposes:

- To control fault current magnitudes during single phase-to-ground faults.
- To control the magnitude of transient over-voltages caused by lightning, switching, and temporary over-voltages on healthy phases during single phase-to-ground faults.

For busbar protection operation only the first purpose is relevant.

Throughout the world, the following four methods of power system earthing are used:

1. Ungrounded
2. High-impedance
   a) Neutral point grounded via reactance (Petersen coil, resonance grounded)
   b) Neutral point grounded via resistor
3. Low-impedance
   a) Neutral point grounded via resistor
   b) Neutral point grounded via reactor
4. Solidly grounded

Ungrounded power systems: Single phase-to-ground faults will cause small currents, so the busbar differential protection can only detect and operate for multi-phase In-Zone faults.

High-impedance grounded power systems: Single phase-to-ground faults do not cause high enough currents for busbar differential protection to operate. Here again, the busbar differential protection can only detect and operate for multi-phase In-Zone faults.

Low-impedance grounded power systems: Single phase-to-ground faults will cause fault currents whose magnitudes are limited by the impedance used in the system neutrals. Presently, the maximum earth-fault currents are limited to between 300 A and 2000 A as specified by country regulations and utility practices. Depending upon load currents and CT ratios, the differential busbar protection may not be sensitive enough to operate for In-Zone single phase-to-ground faults. To assure operation, a sensitive differential element may be required and additional measures applied such as:

- Time delayed sensitive busbar differential protection release by detecting the presence of residual voltage $3U_0$ or neutral current, and
- Additional fourth measuring differential criterion based on zero-sequence currents from all feeder bays connected to the protected busbar.

However, it is important to prevent operation of these elements for heavy external multi-phase faults that can cause CT saturation.

Solidly grounded power systems: Single phase-to-ground faults typically cause high fault currents in the faulted phase, assuring busbar differential protection operation for all In-Zone faults.

4.4 Summation principle / phase segregated protection

4.4.1 Introduction

In three phase systems numerical relays will generally carry out a per-phase measurement (*also called "phase segregated" or "3-phase"*), so that three independent comparison systems exist.

With conventional technology the complexity and cost is however almost three times as high, both in terms of the devices implemented and the amount of wiring required. To simplify this, summation transformer schemes (also called "single-phase" or "summation type") were therefore developed. Note that high impedance differential protection may only be implemented in a phase segregated manner. The use of analogue measuring relays results in a complex arrangement with a large number of devices and a considerable amount of wiring together with associated costs. Phase segregated measurement was therefore only justified in extra high voltage substations. Accordingly, in HV and MV substations, the summation transformer application can be preferred.

4.4.2 Measurement per phase

In this case, a separate comparison of the measured signals is carried out for each phase. This provides the following characteristics:

- clearly identifiable protection response
- the same pick-up threshold for all fault types
- same burden on all current transformers
- redundancy in the case of multiple phase faults

It is however recommended to connect the current transformers with a star point at the protection relay so that a common return (neutral conductor) to the current transformer star point is achieved. Apart from the saving of two control cable cores, the burden on the current transformer is halved in the event of three phase faults.

4.4.3 Summation current transformer version

The phase currents are combined to provide a single phase equivalent AC current (summation current). The summation current ratio of the current must be such that sufficient summation current will result for each type of fault. This summation is typically performed by an interposing CT with four windings (i.e. W1, W2, W3 and W4). The difference in the magnitude of the summation current for various fault types, and with due consideration of the phases affected, should not vary too much.

A number of theoretical analyses have been undertaken to investigate the influence of the in-feed, earthing and load distribution.

Two features of the summation CT connection are worth noting:

- In systems with non effective star point earthing (isolated or resonant grounded system neutral), the different weighting of the phase currents with the summation CT connection results in a phase preference when double earth faults (e.g. cross country faults) occur.
- Due to the possible higher weighting placed on earth currents, an increased sensitivity for earth faults can be achieved. This may be of advantage in systems with earth fault current restriction.

4.4.4 Increased earth fault sensitivity

In practice, the following two summation CT schemes have proven to be successful:

4.4.4.1 Scheme 1 (L1-L3-N connection)

$$\underline{I}_{SUM} = k(5 \cdot \underline{I}_{L1} + 3 \cdot \underline{I}_{l2} + 4 \cdot \underline{I}_{L3}) \quad (1)$$

When considering that $\underline{I}_{L1} + \underline{I}_{L2} + \underline{I}_{L3} = \underline{I}_N$ then (1) is also

$$\underline{I}_{SUM} = k(2 \cdot \underline{I}_{L1} + 1 \cdot \underline{I}_{L3} + 3 \cdot \underline{I}_N) \quad (2)$$

When symmetrical three phase $\underline{I}$ current is applied in Figure 4-10 then the summation current according to (2) can be calculated using the following equation:

$$I_{SUM} = k\left|2 \cdot \underline{I}_{L1} + 1 \cdot \underline{I}_{L3}\right| = k\sqrt{3} \cdot \underline{I} \quad (3)$$

The corresponding nominal (summation) current of the busbar protection is dependant upon the effective winding ratios.

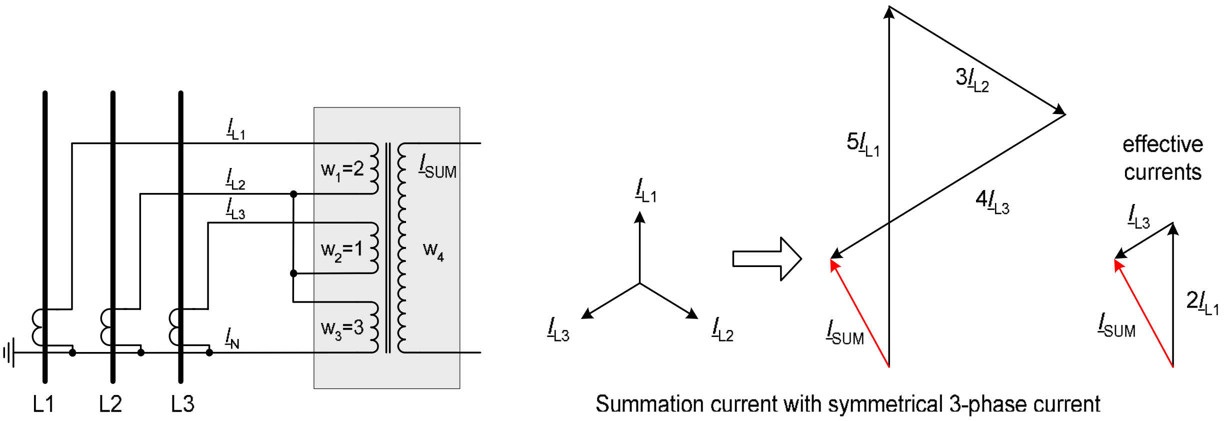


Figure 4-10 Summation CT connection for scheme 1 with increased earth fault sensitivity

4.4.4.2 Scheme 2 (L1-L2-L3 connection)

$$\underline{I}_{SUM} = k(4 \cdot \underline{I}_{L1} + 3 \cdot \underline{I}_{L2} + 2 \cdot \underline{I}_{L3}) \quad (4)$$

When symmetrical three phase current I is applied in Figure 4-11 then the summation current according to (4) can be calculated using the following equation:

$$I_{SUM} = k\left|4 \cdot \underline{I}_{L1} + 3 \cdot \underline{I}_{L2} + 2 \cdot \underline{I}_{L3}\right| = k\sqrt{3} \cdot \underline{I} \quad (5)$$

The corresponding nominal (summation) current of the busbar protection is dependant upon the effective winding ratios.

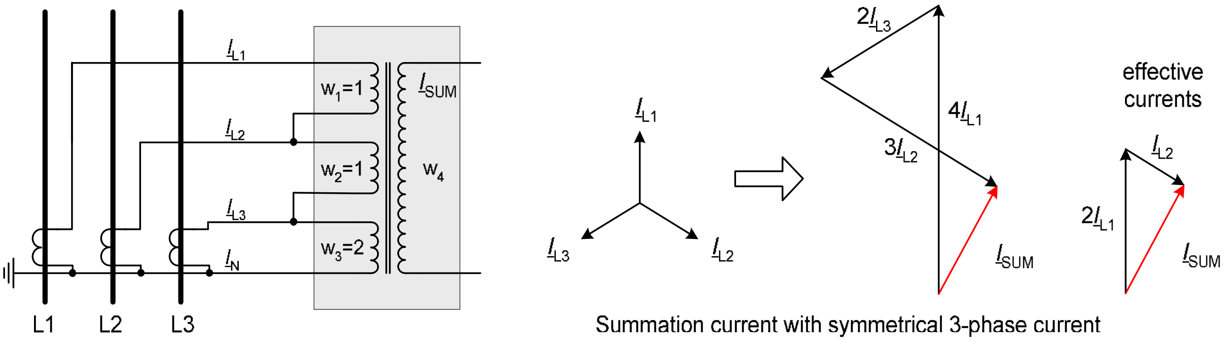


Figure 4-11: Summation CT connection for scheme 2 with increased earth fault sensitivity

The following relative pick up sensitivities (i.e. pickup for internal three-phase fault is taken as reference) can then be calculated for the various types of fault for the two different schemes:

Table 4-1 Pick up sensitivity for various fault types and different schemes

Fault type	Relative pick-up threshold Scheme 1	Relative pick-up threshold Scheme 2
L1-L2-L3	1,00	1,00
L1-L2	0,87	1,73
L2-L3	1,73	1,73
L3-L1	1,73	0,87
L1-N	0,35	0,43
L2-N	0,58	0,58
L3-N	0,43	0,87

According to the weighting of the earth current a large summation current arises during earth faults. Correspondingly, the pick up threshold for this type of fault is more sensitive. On the other hand, the protection is relatively insensitive to phase-phase faults L2-L3 and L3-L1 (scheme 1) respectively L1-L2 and L2-L3 (scheme 2).

The earth short circuit currents may be very small in systems using earth current limiting devices (neutral earthing via impedance). The earth current sensitivity according to Table 1 in such case may not be sufficient. In this instance the earth current may be increased by the use of an interposing CT. The relative weighting of the earth current is then proportionally increased.

4.4.5 Normal earth current sensitivity

The earth fault short circuit current in solidly earthed networks has the same order of magnitude as the phase-phase fault short circuit current. The over proportional weighting of earth currents therefore leads to very large currents in the secondary circuit of the summation CT and severely loads the measuring circuits (e.g. high voltages on the pilot wires). Furthermore, a large burden appears at the main current transformers as the impedance of the summation CT secondary circuit is transformed to the primary side by the square of the turns ratio. A summation CT connection with reduced earth current sensitivity should be considered particularly in those cases where the earth short circuit current may be greater than the three phase short circuit current. For this purpose the summation CTs may be connected in the following ways:

4.4.5.1 Scheme 1 (L1-L2-L3 connection)

For this case the summation CT will be connected as follows

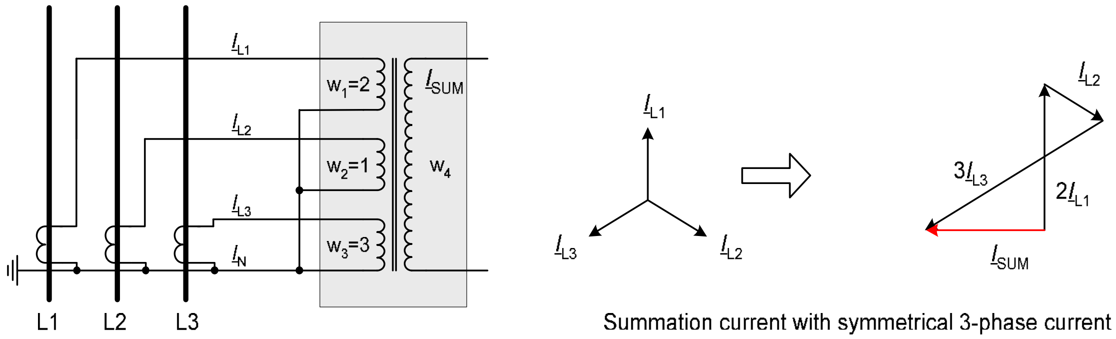


Figure 4-12: Summation CT connection for scheme 1 with normal earth fault sensitivity

Equation (2) is therefore modified as follows:

$$\underline{I}_{SUM} = k\left(2\cdot \underline{I}_{L1} + 1\cdot \underline{I}_{L2} + 3\cdot \underline{I}_{L3}\right) \qquad (6)$$

4.4.5.2 Scheme 2 (L1-L3-N connection)

For this case the summation CT will be connected as follows:-

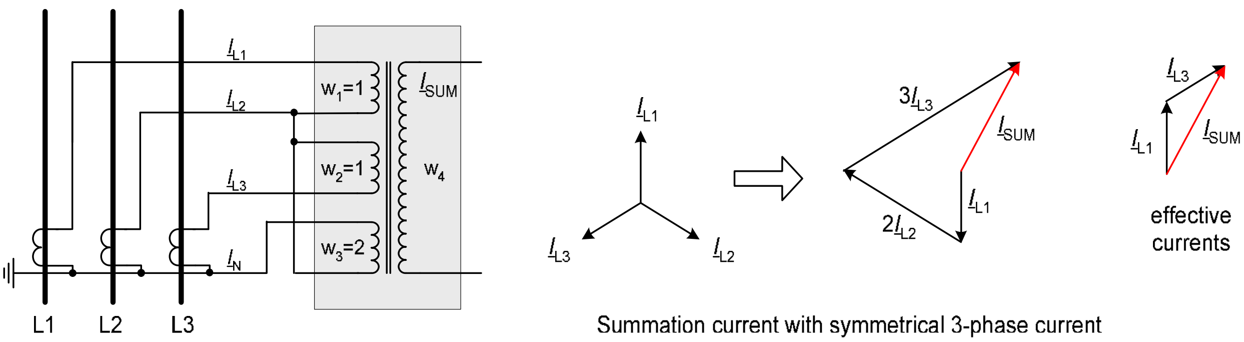


Figure 4-13: Summation CT connection for scheme 2 with normal earth fault sensitivity

In this case equation (4) is modified as follows:

$$\underline{I}_{SUM} = -k\left(\underline{I}_{L1} + 2\cdot \underline{I}_{L2} + 3\cdot \underline{I}_{L3}\right)$$

The relative pick-up sensitivities are indicated in Table 4-2 for this case:

Table 4-2 Pick-up sensitivity for various fault types and different schemes

Fault type	Relative pick-up threshold Scheme 1	Relative pick-up threshold Scheme 2
L1-L2-L3	1,00	1,00
L1-L2	1,73	1,73
L2-L3	0,87	1,73
L3-L1	1,73	0,87
L1-N	0,87	1,73
L2-N	1,73	0,87
L3-N	0,58	0,58

4.4.6 Internal fault with superimposed load current

A degree of load current may continue to flow even when an internal fault is present:

- Via the healthy phases in case of a non-symmetrical fault
- Via the fault location itself, if it is not a solid short circuit
- During single-pole faults with high impedance neutral earthing.

With a summation CT connection this results in a reduction in the pick-up sensitivity of the differential protection due to the additional stabilization caused by the load current flowing through the protected object.

4.4.7 CT requirements

Summation type busbar protections basically have the same main CT requirements as phase segregated BBP. However the additional burden of the summation CTs must be considered when verifying the behaviour of the CT, e.g. the necessary knee point voltage or the minimum saturation free time.

4.4.8 Characteristics of the summation CT principle

The summation CT principle is characterized by the following features:

- Only one measuring system is used for all types of fault
- The sensitivity varies depending on the type of fault and phases involved
- Any remaining load current may produce a stabilizing current and decrease the sensitivity
- No indication of the faulted phases
- in one installation only one summation CT - connection scheme must be used

4.5 Additional tripping criteria (i.e. check zone, U<, I>, etc.)

Depending on the user requirements sometimes it is necessary to use additional tripping criteria for busbar protection. Some typical examples are presented in this section.

4.5.1 Check Zone

When CT-circuits are switched then, dependent upon the position of the busbar disconnectors it is possible that some of the CT secondary circuits can be open circuited in error. This can cause unwanted operation of the differential protection scheme. For this reason, a so-called check zone is often required for a traditional high-impedance busbar protection scheme when switching of CT-circuits is required. The check zone is fixed and has no CT switching in any of the outgoing circuits and is not connected to the busbar section and busbar coupler bays. The check zone will detect faults anywhere in the substation but cannot distinguish in which part of the station the fault is located. When the check zone detects a fault it issues a release signal to the busbar protection relays in all individual, discriminating zones. The busbar protection discriminating zones will then trip that part of the substation that is faulted. However, this principle creates not only a high cost, as separate CT cores are required, but also the need for extra cabling and a separate check zone differential relay.

Modern numerical busbar differential relays might include an internal check zone connected to the same CT cores as the main discriminating zones. In that case the check zone provides additional security against the incorrect status of busbar disconnector auxiliary contacts and is used as an additional criterion in event of a busbar fault.

4.5.2 Current directional comparison

The relative positions of the fundamental frequency current phasors, in all bays connected to one discriminating zone, are compared phase wise. In the case of an internal fault phasors from all bays will be approximately in phase (i.e. all bays will feed current into the faulted busbar). In the case of an external fault the fundamental frequency current phasor in a faulted bay will be displaced for approximately 180° from all other pha sors (i.e. all bays except the bay with the external fault will feed current towards the busbar). Extra care shall be taken in the design of the relay to secure correct operation of this principle for heavy CT saturation during external faults.

4.5.3 Phase under-voltage release criterion (U<)

In general, a short circuit on a busbar causes a voltage collapse. The ‘under-voltage function’ senses this collapse and can be used to release the busbar protection tripping command.

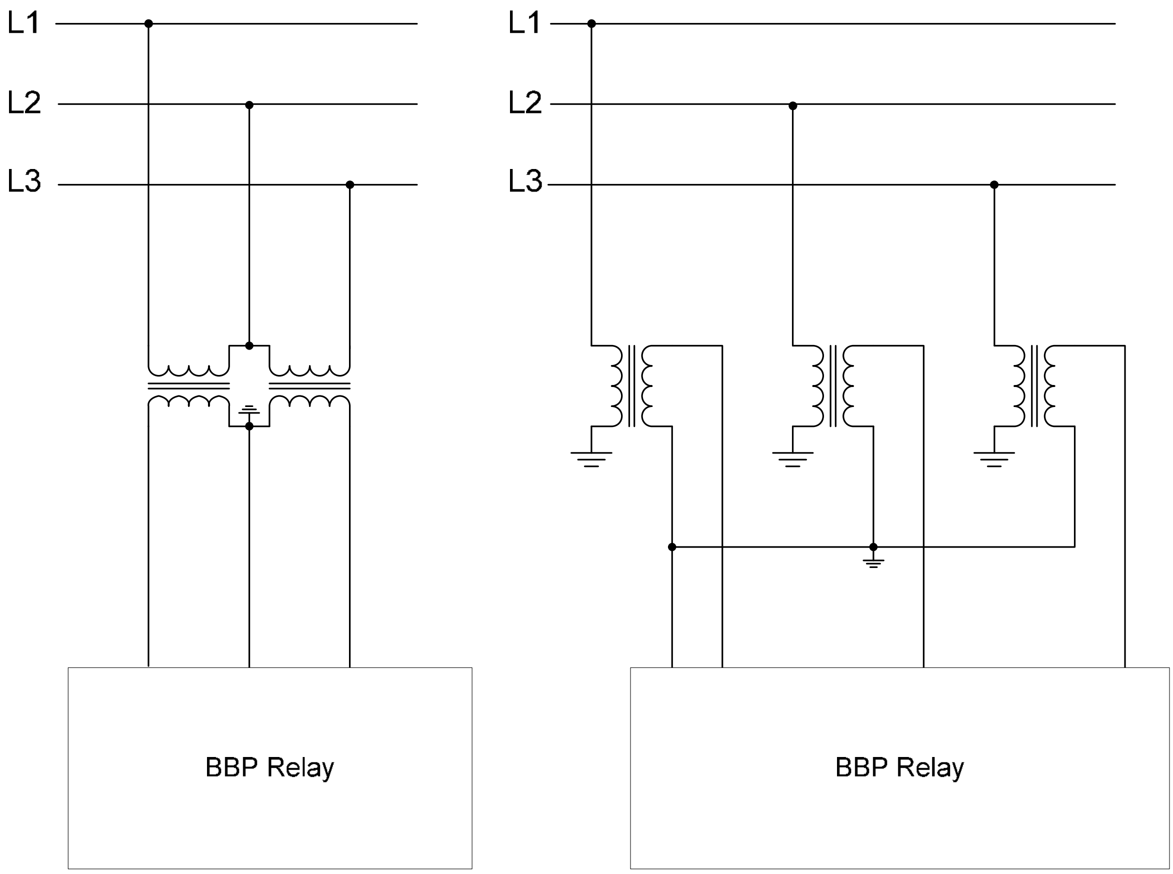


Figure 4-14 Phase under-voltage release criterion

The evaluation of the busbar can be accomplished by two different methods (see above Figure).

Version 1: With the VT. ‘V- arrangement’, the phase-to-phase voltages can be evaluated. The busbar system measures the values of the phase voltages U_{L1-L2}, U_{L1-L3} and U_{L3-L1}.

Version 2: With the VT. ‘Y (star)- arrangement’, the phase-to-phase voltages and the phase to ground voltages can be evaluated.

4.5.4 Voltage sequence components release criterion (U1<, U2>,3Uo>)

In some countries this criterion is used instead of the phase under-voltage criterion described above. A short circuit on a busbar will cause a reduction of the positive sequence voltage component and an increase in the negative and zero sequence voltage components. Detection of any of these three conditions (i.e. OR logic) can be used to release the busbar differential protection.

4.5.5 Neutral over voltage release criterion (3Uo>)

A ‘neutral over voltage release criterion’ should be considered for impedance grounded networks. Under normal operation, or during a phase-to-phase fault condition, without ground connection, the neutral voltage (sum of the phase to ground voltages) is almost zero. A ground fault in an impedance grounded network is characterized by the fact that the neutral voltage reaches a certain value very quickly. The amplitude of the voltage value depends on the relationship between the fault resistance and the grounding impedance.

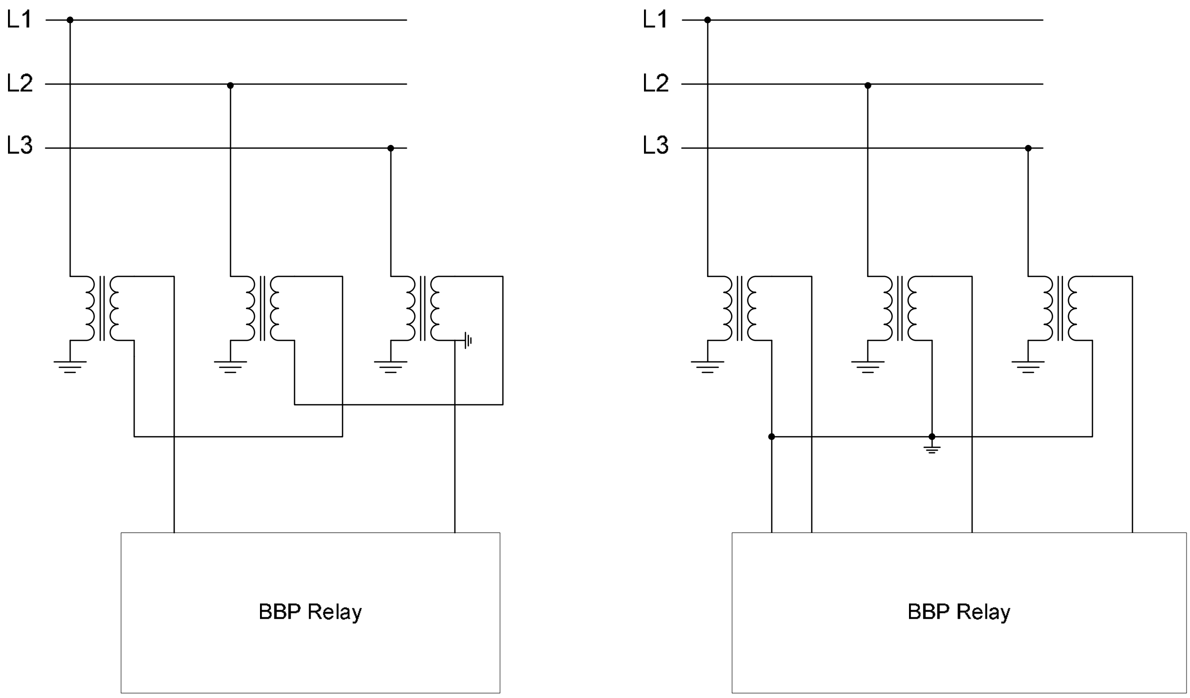


Figure 4-15 Neutral over-voltage release criterion

4.5.6 Neutral over current release criterion (3Io>)

A ‘neutral over current release criterion’ only has to be considered for impedance grounded networks. Under normal operation, or during a phase-to-phase fault condition without ground connection, the neutral current is zero. A ground fault in an impedance grounded network is characterized by the fact that a current will exist in the transformer neutral. The amplitude of the current value depends on the relationship between the fault resistance and the grounding impedance.

4.5.7 Overcurrent release of the trip command

It is occasionally specified that when tripping a busbar zone only those feeders are tripped which are actually contributing fault current (active feeders), while those which are not (passive feeders) are left connected. This logic can be achieved by configuring an additional current check feature per bay, which only enables tripping of feeders that are actually contributing fault current.

4.5.8 External release of the trip command

It is occasionally required that some external signal is used to release a trip of the busbar protection. Typically, these signals originate from some external relay(s), which work on one of the principles described above.

4.6 Busbar protection requirements

The main requirements for busbar protection are dependability, security, speed, sensitivity, and selectivity.

4.6.1 Dependability

Sometimes more than one BBP system is used in parallel to increase the dependability of the protection system. In such a configuration, a busbar fault can be cleared by a trip performed by at least one of the parallel BBP systems. If, in certain circumstances, one of the BBP does not detect the fault, there is a good chance that another BBP will detect and clear the fault, Figure 4-16.

To increase the dependability when using this solution, the BBP systems should be as independent as possible. Each BBP should have different working principles, i.e. they should have different algorithms, be energized from independent power supplies, use independent auxiliary tripping voltage, tripping circuits and measure input currents from independent CT cores. Sometimes, it is not possible to fulfil all of these requirements, but a compromise solution must be met.

Practice shows that, in a compromise with other factors like security and cost, the duplication of BBP is a good choice when considering increasing dependability.

However, the increase in dependability as a result of using more than one BBP will reduce the security of the protection system, since the probability of an unwanted trip by the system is now the product of the probability of a mal-operation of each BBP.

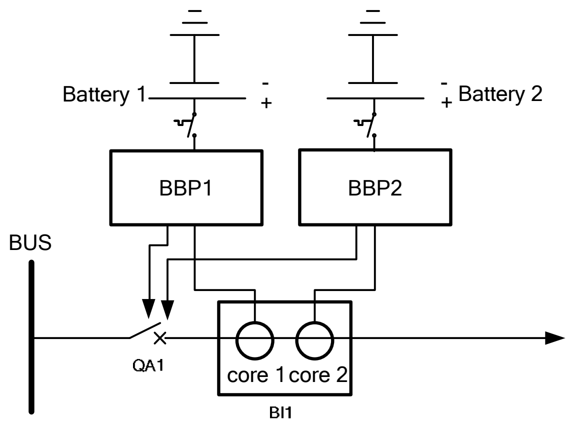


Figure 4-16: Redundant BBP to increase the dependability of the system.

4.6.2 Security

The security of a protection system is quality to remain stable i.e. it must not trip during an external fault. This can be achieved by increasing the number of tripping conditions necessary to clear a busbar fault. Subsequently, the busbar fault is cleared only when all of the tripping conditions are fulfilled at the same time.

The use of additional tripping criteria is one way of achieving this. As explained in Section 4.5 the check zone criteria and phase under-voltage release among others are good examples of tripping conditions used to increase the security of the protection system.

The new numerical BBP systems have these functions integrated into them so that all of this tripping logic is reduced to a simple ‘AND’ function between the current differential function and the additional tripping function criteria, see Figure 4-17a).

In some utilities, to increase the independence between conditions, additional tripping criteria such as a check zone is performed by a separate check zone relay which sends a release command to the differential relay when a busbar fault occurs (see Figure 4-17b).

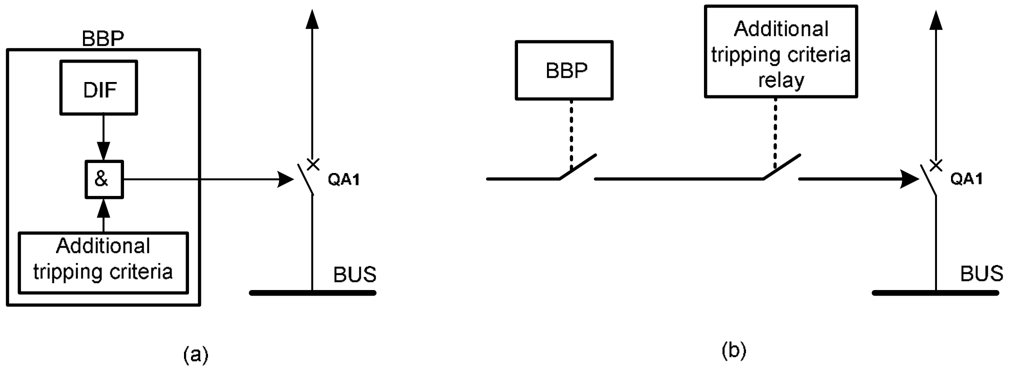


Figure 4-17: (a) Integrated current differential function and the additional tripping criteria in the same BBP
(b) Separate current differential protection relay and additional criteria relay,

Increasing the number of BBP systems and placing their tripping commands in series is another method that is used to increase the overall security of the protective system. The use of a check zone relay in series with the busbar differential relay could be seen as a particular instance of this solution. Here all of the BBPs have to trip at the same time to clear busbar faults. In a similar manner to the dependability issue, BBPs should be as independent as possible and so independent power supplies, independent auxiliary voltage, independent tripping voltage, independent tripping circuits and independent measuring input currents from independent CT cores should be used, Figure 4-18.

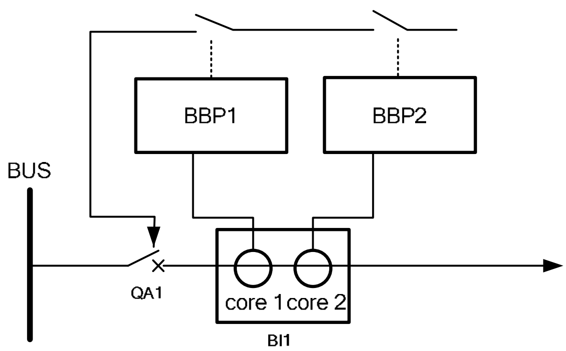


Figure 4-18: Increasing the security of the system by using two BBPs in series.

Attention should be paid to this solution as it will inevitably reduce the dependability of the protection system.

The probability of an uncleared busbar fault by a protection system is related to the system probability of not seeing the fault. The more dependent the system is, such as introducing two BBPs in series to clear a fault, the higher the probability of failing to clear a fault.

In this case, the probability of an uncleared busbar fault is the product of the probability of each BBP not seeing the fault.

4.6.3 Speed

The main purpose for using BBP is to prevent damage to primary and secondary equipment and to preserve the network transient stability. To achieve this, fast BBP operation is required. Today, relays with operating time of less than one cycle are available. However, the fault clearing time includes both the BBP operating time plus the CB clearance time.

4.6.4 Sensitivity

For purposes of coordination, all main protections and remote back-up protections should be equally as sensitive as regards fault detection. However, in practise this can be difficult to achieve.

The capability of the protection system to detect high resistive faults is also one of the requirements for the BBP system. If this protection does not have sufficient sensitivity, there is a risk that a busbar fault will not be cleared by the BBP but will be cleared by back-up protections which are usually remote zone 2 relays and remote earth-fault overcurrent relays. Although the increase in clearance time is not as important since the fault current is small, this could be of considerable consequence since the number of circuits removed from service could be larger resulting in much more important network contingences.

4.6.5 Selectivity

Selectivity is one of the most important requirements that utilities demand from BBP systems. Two types of selectivity exist: zone selection and coordination selectivity.

If the substation topology encompasses several protection zones it is desirable to clear busbar faults without shutting down the entire substation. For this reason, the BBP system has to be able to handle more than one protection zone and trip only the circuit-breakers particular to the affected zone when a busbar fault occurs.

It is also common to require phase discrimination by the BBP system at the network transmission level. Although the trip commands by these protections are always three phase, it is desirable for substation personnel to recognize the faulted phase and to visually check the power apparatus for damage without compromising the return to service of the faulted busbar. Phase discrimination signalling is an important aid in such a procedure.

Concerning coordination selectivity, the BBP system should satisfy the network protection requirements. For a network fault, the protection system should remove only the minimum network element to clear the fault. This means the BBP system should be faster than its back-up protections.

4.7 Location of the substation in the grid

When considering all of these requirements: (dependability, security, speed, sensitivity and selectivity) the importance of the substation in the network is the most relevant aspect in designing the BBP. It is the network demand that precedes the requirements and design of the BBP system. Several criteria determine the importance of a substation in a power system:

- **Preserving Network Stability** – Fast fault clearance time is of extreme importance to maintain the stability of a power grid. If a busbar fault on a substation is cleared by remote back-up protections, the fault clearance time may be too long. This can result in a number of substations/lines being removed from service causing unbalance between power generation and consumption, and possible system collapse.
- **Selectivity** – There are utilities that require very strict selectivity criteria which have to be achieved under all service conditions. Sometimes this can only be achieved by using a BBP coordinated with remote backup protections.
- **Preventing Loss of Production / Load** – Some substations supply critical loads where the shutdown of the entire network element without selectivity due to a busbar fault is unacceptable. This also includes power plants.
- **Nuclear Plants Specification** – Nuclear plants require that all network faults near the power plant should be cleared selectively within specified clearance time. To fulfil these requirements it may be necessary to install BBPs in all substations used for network interconnection.
- **Power Quality** – The duration of the voltage dip (due to the long fault clearance time) and the under voltage state (due to the system reconfiguration after an unselective busbar fault clearance) are the two power quality reasons for investing in the BBP system. In fact, it is not unusual for customers to have supply contracts that penalize the grid company for power quality issues.
- **Avoiding Auto-Source Transfer Schemes** – Auto-source transfer schemes are used to transfer load from the lost power source to an alternative source. These special schemes may be complex and expensive. The use of a BBP system may minimize network reconfigurations and is a good solution to avoid auto-source transfer schemes.
- **Regulatory Reliability Requirements** – In some countries, regulatory requirements for utilities to ensure reliable and high quality of power supply to customers are strict, resulting in high penalties if not achieved. In fulfilling these requirements, the use of BBP systems may be justified.
- **GIS** – In GIS substations, fast fault clearance time is essential to prevent extensive damage to the primary equipment. Delayed fault clearance by a remote back-up protection is not acceptable so it is easy to justify BBP systems.

The approach to designing a BBP for a non-critical substation in the power grid should be different to the approach when designing a BBP for a critical substation. Non-critical substations may rely on busbar fault clearance by remote back-up protections because the slow clearance of faults may not impact the integrity of the network system. Therefore, BBP systems may not be required or simple BBP solutions can be utilized. On the other hand, for critical substations, complicated BBP schemes or more than one BBP may be used to achieve high reliability.

4.8 Unavailability of a BBP

As with all protection devices used in a power system, the BBP can at some point in time fail. In a BBP two failure types exist, a complete failure and a partial failure. A complete failure is when the device is no longer able to perform its main task, to detect and clear bus faults. A partial failure is when the BBP is unable to correctly evaluate the differential function for all protection zones. This situation occurs when there is a problem in a bay or several bays related to an isolator replica position, a CT measurement error, a bay unit error, or an optical fibre problem between the central unit and a bay unit. Typically, in this case, it is possible for the BBP to continue to operate but only partially protect the substation. As an example, in a breaker-and-half substation arrangement, if the central unit loses the optical fibre connection to a bay unit which measures one bus current, the BBP is no longer able to perform a differential protection function for that particular bus but it can continue protecting the remaining bus.

The consequences of BBP unavailability are the loss of selectivity for bus faults and the increase of fault clearance time. Under partial unavailability of the BBP, only faults occurring in the unprotected zones experience loss of selectivity and the increase of fault clearance time. Healthy zones will not be affected.

Actions taken when the BBP unavailability is detected depend on the utility practices. Some utilities take no actions, while some adopt contingency plans such as:

- **Redundant BBP** – for critical substations, where BBP unavailability is unacceptable, the redundant BBP is commonly used.
- **Change of substation topology** – by opening critical circuit breakers or isolators, it is possible to increase selectivity. For example, in a double bus with a bus coupler, by opening the bus coupler to separate two buses, selectivity is increased since the number of circuits affected by a bus fault is reduced.
- **Change of network and generation topology**– the impact of the BBP unavailability may be reduced by changing the network and generation topology to minimize the affected area in case of a busbar fault.
- **Settings changes** – it is possible to shorten the fault clearance time by reducing the remote Z2 backup time, by activating special teleprotection schemes or by reducing the operation time of local overcurrent functions or even activating them. One typical overcurrent function used for this purpose is the bus coupler overcurrent function. Setting changes can be difficult to implement in a short period of time and in older generation protections since they frequently have to be made manually and the number of protections involved may be very large. The potential for human errors to occur are always a risk in these situations. With new numerical protections and using standard protocols such as IEC 61850 this temporary setting change can be made in a completely automated manner. This reduces the required time to perform the changes to almost instantaneously and eliminates the chance of human errors during the process.

The required time to implement these contingency plans and to allow these changes to be active while no maintenance repair is done is also specified by the utilities practices.

4.9 Substation design issues

The importance of the substation in the network is the most relevant criteria in deciding how complex a BBP system is required. Substation topology is the second most relevant criteria in the design process.

BBP design and its redundancy depend on the substation design and arrangement. For example, for a single busbar substation, redundancy of BBP system might be questionable. However, in a breaker-and-half busbar substation redundancy of BBP system may be a good solution.

A proper substation design results in increased security of the BBP system. An example is a BBP system designed with several independent protection zones. In case of a busbar fault, BBP protection will isolate only the affected zone from the network. The rest of the substation will continue normal operation. At the same time, an unwanted trip will be confined to a single protection zone, and the number of feeders that will be disconnected due to a mal-operation will be reduced. Conversely, if the substation has only one protected zone, the BBP operation will shutdown the entire substation.

Table 4-3 compares different substation arrangements described below.

4.9.1 Single busbar

The single busbar arrangement is the simplest substation topology. Substation design from Figure 4-1 includes a bus section circuit-breaker. However, there are designs where this circuit-breaker does not exist, meaning there is only a single busbar. In substations with the bus section circuit-breaker, the BBP considerations can be included in the double busbar with bus coupler arrangement, see Section 4.9.2.

In the single busbar arrangement there is only one protected zone, which is defined by the location of all feeder CTs. Dependability in clearing the busbar faults is ensured by remote backup protections. When a busbar fault occurs, the BBP will trip all circuits connected to the busbar, shutting down the entire substation. If for any reason the BBP does not operate, the remote Zone 2 distance protections will trip with time delay and the substation will be shut down. This action will also result in disconnection of the line to this substation and all load connected to this line will lose power as well. Duplicating BBP will increase dependability and ensure fast fault clearance time if one of the two BBP fail to clear a bus fault.

System security is another reason which justifies the duplication of BBP as discussed in section 4.6.2.

4.9.2 Double busbar single breaker

In substations with a double busbar single breaker with bus coupler arrangement, two BBP zones exist. When the bus coupler is open, busbar faults are directly fed by its connected feeders. During the process of clearing a bus fault, the BBP will open all corresponding circuit-breakers and isolate only the affected zone. The second zone (where fault does not exist) will remain stable since its differential current will stay near zero. If for any reason the BBP fails to operate, the fault will be cleared by remote back-up protections, typically Zone 2 distance protections. The number of circuits disconnected will be the same as when the BBP operated properly since the dependability is ensured by back-up protections and the selectivity is ensured by the open state of the bus coupler. The downside is that the fault clearance time is now dependent on the setting of the remote Zone 2. In addition, the tap loads connected to the supplying line will be disconnected as well.

Even in case of an unwanted operation of the BBP that causes trip of one protected zone, only the associated feeders will be disconnect from the power system.

This is an example of how the substation arrangement improves the BBP system security and selectivity.

When the bus coupler is closed and the BBP system is active, the isolation between protected zones is achieved by the correct selectivity of the faulted zone and the opening of the corresponding circuit-breakers and bus coupler circuit-breaker. In case of a busbar fault which is not cleared by the BBP, the remote back-up protections will clear the fault resulting in the shutdown of the substation and increasing the fault clearance time. Here the duplication of the BBP to increase the dependability and selectivity of the system is a good solution.

When for some reason facilities that will enable the splitting of buses are not available (e.g. BBP out of service, bus coupler bay out for maintenance, no busbar splitting scheme, etc), the substation can be operated with the bus coupler open if there are no other restrictions which prevent such operation (e.g. power flow constraints). This solution has a certain degree of selectivity because the system is running with two independent buses. If splitting of the busbars imposes constraints on powerflow, an alternative solution could be to connect all feeders to one busbar only. This will also reduce the probability of a busbar fault, as one busbar with all its equipment is de-energized. However, during such operating condition a busbar fault will shut down the whole substation.

Operating a double busbar single breaker station in an on-load transfer condition will cause the loss of the entire substation in case of a busbar fault, because the BBP will consider the whole station as a single protection zone. When such operation is unavoidable for a longer period of time, the utility should check the impact on the power system in the event of a busbar fault.

4.9.3 Double busbar with transfer bus

For the double busbar substation with transfer bus, see Figure 4-3, there is the possibility of placing a bay in service and connecting it to one of the two busses using the transfer bus. In this situation the bay is in transfer to its circuit-breaker and uses the bus coupler circuit-breaker to clear faults.

In this topology the feeder CT location (e.g. internal / external to the transfer disconnector) is relevant to the BBP operation, refer to Section 9.3. From the BBP operation point of view the most interesting location is the external CT, when a bay is in transfer, a third protection zone exists limited by the bus coupler CT and the feeder in transfer CT.

In the situation of a busbar fault in the busbar connected to the transfer bus, the BBP will clear the fault by opening all connected circuit-breakers including the bus coupler circuit-breaker. In the situation of a busbar fault in the transfer bus, only the bus coupler circuit-breaker will open but the fault will continue to be fed by the transfer bay remote end. In this case, the elimination of the transfer bus fault is achieved by a transfer-trip command to the remote end performed by the BBP or by the remote end Zone 2 protection.

This resemblance to the double busbar with bus coupler arrangement makes all the dependability and security issues true for both arrangements.

4.9.4 Triple busbar

In a triple busbar arrangement, see Figure 4-5, the application of a BBP follows the same criteria as in the double busbar arrangement substation topology with the peculiarity of having a third busbar and therefore a third protection zone.

By increasing the number of buses the feeders can be more evenly distributed across the three buses and as a consequence the system selectivity and security is improved. When a busbar fault is cleared or a mal-operation of one BBP zone occurs, fewer feeders are switched out meaning that a larger number of bays can remain in-service.

4.9.5 Breaker-and-a-half arrangement

In a breaker-and-a-half substation arrangement, see Figure 4-6, a BBP trip in one of the busses isolates the respective busbar but does not disconnect any feeder since they will continue to be connected to the other busbar. This is one of the main advantages of this type of substation arrangement, meaning that this arrangement has the highest degree of selectivity and security.

In this topology the BBP has two independent protection zones, each associated with their own busbar. The implementation of this protection is simpler than a double busbar arrangement since there is no CT switching, transfer buses, bus coupler, etc..

The system dependability is similar to that of a double busbar single breaker arrangement. Back-up protection continues to be provided by remote end Zone 2 and if there is a busbar fault that is not cleared by the BBP, the entire substation and tapped loads will be switched off. If there is no redundancy of the BBP system the advantage of this arrangement will be compromised in case of a BBP failure. The redundancy could result in a reduction in system security, as explained before, but, unlike the other substation arrangements, an unwanted trip will not disconnect any feeder except to isolate the faulted busbar and result in all substation feeders being connected to one single busbar. Therefore, redundancy of the BBP is not followed by a reduction of the system security.

As a result, in these substations the use of a second BBP system is justifiable.

4.9.6 Double busbar with double breakers

For double busbar double breakers substation arrangements, see Figure 4-4, the considerations are similar to that of the breaker-and-a-half topology. However note that it is of outmost importance to utilize re-trip feature for breaker failure protection (see section 8.1.3) when CBF starting for both breakers in one feeder bay is initiated from a single contact or a single protection relay and CBF pickup is set under load current of the feeder.

4.9.7 Ring busbar

In ring type substations, see Figure 4-7, the protection of the busbar is typically not performed by BBP systems as explained in the previous arrangements. Here, each busbar segment is limited by two consecutive circuit-breakers being protected by the corresponding feeder protection that measures the two adjacent CT currents.

Table 4-3 BBP: comparison in several substation arrangements.

<table>
<tr><th>Busbar arrangements</th><th>Nº of protective zones</th><th>Isolator replica</th><th>Reasons for BBP redundancy</th><th>Consequences of a busbar fault cleared by the BBP</th><th>Consequences of a busbar fault not cleared by the BBP</th><th>Consequences of a an unwanted trip by the BBP</th><th>Actions within the substation topology to remediate the loss of the BBP</th><th>Consequences of a BF action</th></tr>
<tr><td>Single busbar</td><td>1</td><td>No</td><td>Increases dependability.</td><td>Loss of the entire substation.</td><td>Fault cleared in remote back-up time. Loss of the entire substation plus the tap lines.</td><td>Loss of the entire substation.</td><td>Nothing can be done.</td><td>Loss of the entire substation. Possible intertrip to the remote ends.</td></tr>
<tr><td>Double busbar single breaker</td><td>2</td><td rowspan="2">Yes</td><td rowspan="2">Increases dependability, although it is possible to increase dependability by simply keeping the bus-coupler CB open.</td><td rowspan="2">Loss of a single busbar. Loss of the entire substation if fault occurs in the bus coupler dead zone or during an on-load transfer condition</td><td rowspan="2">Fault cleared in remote back-up time. Loss of a single busbar if bus coupler is open. Loss of the entire substation if bus coupler is closed.</td><td rowspan="3">Loss of a single busbar.</td><td rowspan="3">Open the bus coupler or transfer all feeder to one bus</td><td rowspan="2">Loss of a single busbar, possible intertrip to the remote ends. If the BF operates in the bus coupler breaker, loss of the entire substation.</td></tr>
<tr><td>Double busbar with transfer bus</td><td>2 or 3</td></tr>
<tr><td>Triple busbar</td><td>3</td><td>Yes</td><td>Increases dependability although the third busbar adds an extra degree of dependability than the double busbar arrangement.</td><td>Loss of a single busbar. Loss of two buses if the busbar fault occurs in the bus coupler dead zone or during an on-load transfer condition</td><td>Fault cleared in remote back-up time. Loss of a single busbar if bus coupler is open. Loss of two buses if bus coupler is closed.</td><td>Loss of a single busbar, possible intertrip to the remote ends. If the BF operates in the bus coupler breaker, loss of two buses.</td></tr>
<tr><td>Breaker-and-a-half</td><td>2</td><td>No</td><td>To maintain the high dependability achievable by this arrangement it is important to duplicate the BBP.</td><td>None. The service continues to be done by the other busbar.</td><td>Fault cleared in remote back-up time. Loss of the entire substation plus the tap lines. Loss of a single busbar If middle breakers are open.</td><td>None. All the connected feeders continue in service from the other busbar.</td><td>Open all middle breakers.</td><td>If the BF operates for a busbar breaker adjacent bus is tripped, an intertrip to the center breaker and to the remote end is sent. If the BF operates for one center breaker, loss of the corresponding diameter and intertrips to the adjacent two feeders remote ends are sent.</td></tr>
</table>

5 Design issues

5.1 Busbar protection arrangement

5.1.1 Conventional arrangement

In the past, before numerical de-centralized busbar protection was available, busbar protections were constructed centrally. All process data, such as CT currents, isolator positions and tripping channels had to be wired back towards the central position of the busbar protection panel. Considerable interconnection (such as start circuit breaker failure protection, block auto-reclosure, etc.) between the other protection panels had to be made. In those conventional arrangements, many cables had to be used, the engineering, commissioning and maintenance was quite time consuming and costly.

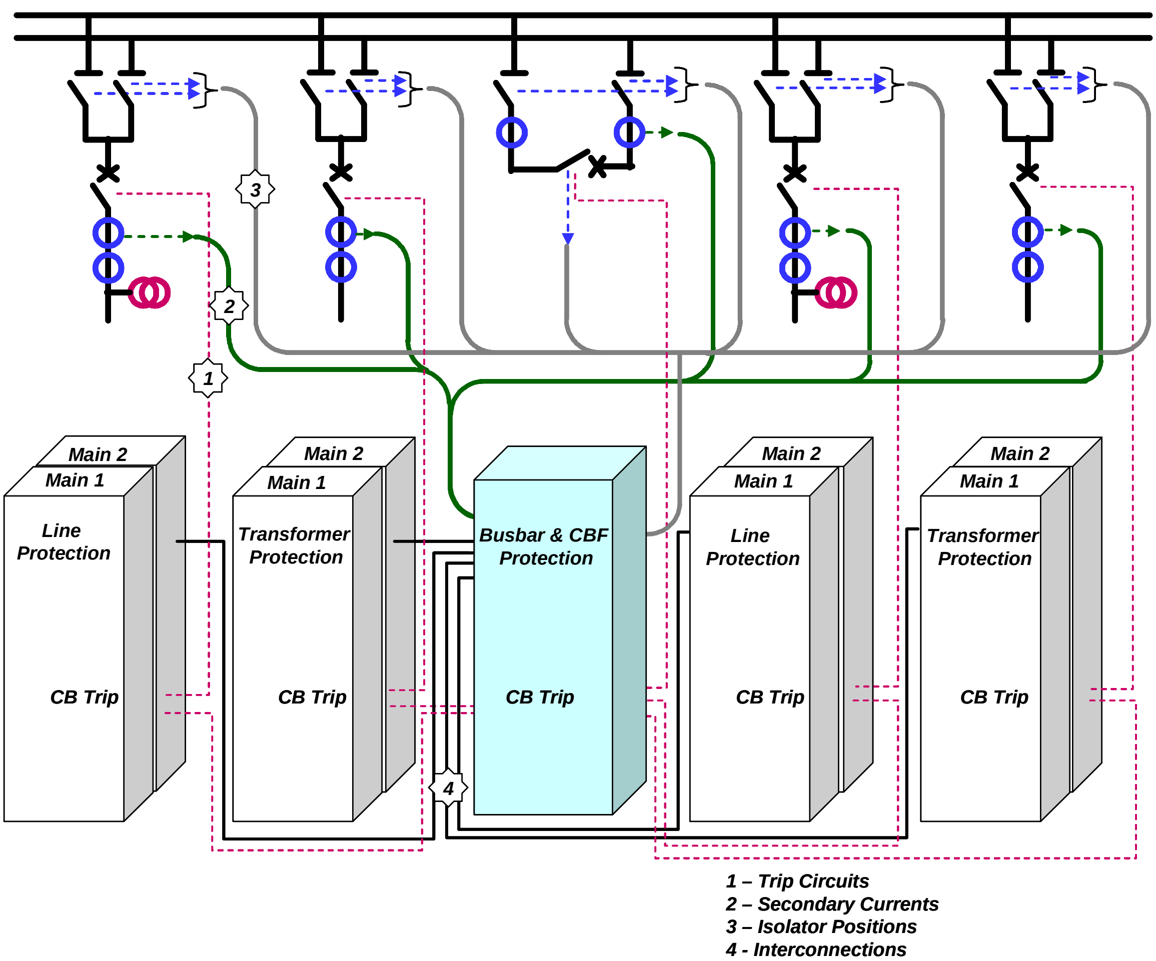


Figure 5-1 Conventional arrangement

5.1.2 Numerical centralized arrangement

Numerical centralized busbar protection can be found in new substations as well as where retrofit of old conventional BBP was made and the cables were still in good condition. In a numerical centralized arrangement the amount of cabling is approximately the same as it was in conventional arrangements. A reduction can only be made, if additional protection functions are gathered in the busbar protection relay (e.g. busbar- and circuit breaker failure protection). The advantage of using numerical protection equipment is the easy adoption of functionality and simple arrangements of I/O. Furthermore, the numerical technique allows fast and easy connection with substation automation systems which allow fast fault analysis and monitoring.

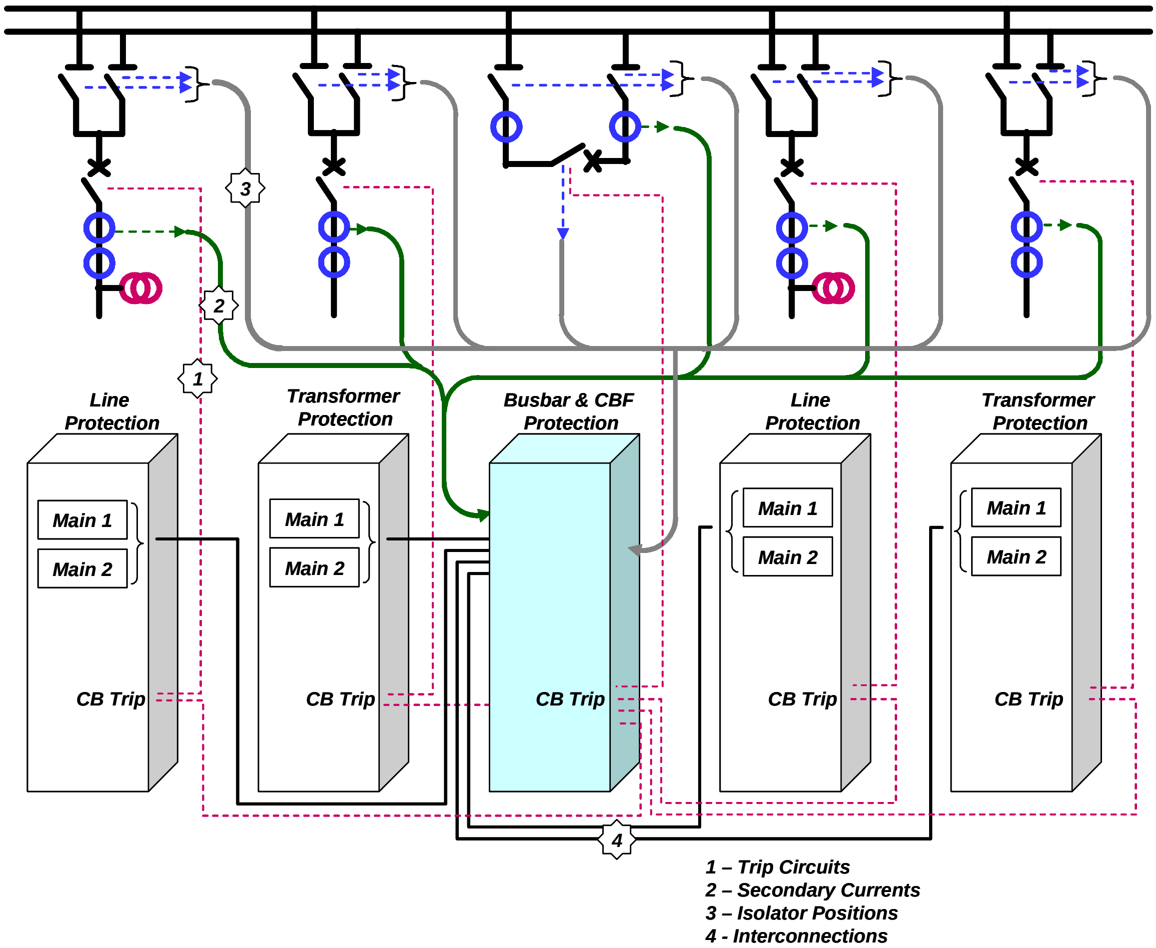


Figure 5-2 Numerical centralized arrangement

5.1.3 Numerical decentralized arrangement

In new and refurbished substations, where the cabling is completely new, numerical decentralized busbar protection can often be used today. Bay dedicated protection panels can be built, where the bay units of the de-centralised busbar protection are located close to the bay protection devices. Therefore, only very short distances have to be hard - wired (e.g. start circuit breaker failure protection, block auto-reclosure, etc.). The long distances between panels are bridged with one fibre optic cable per bay unit to the central unit. Beyond the high savings made on cabling other cost efficiencies can be achieved. The bay protection panel designs can be replicated. During engineering, testing, commissioning and maintenance work this concept can save time. Further savings can be made, if more integrated functionalities are used if this is acceptable from the overall dependability point of view.

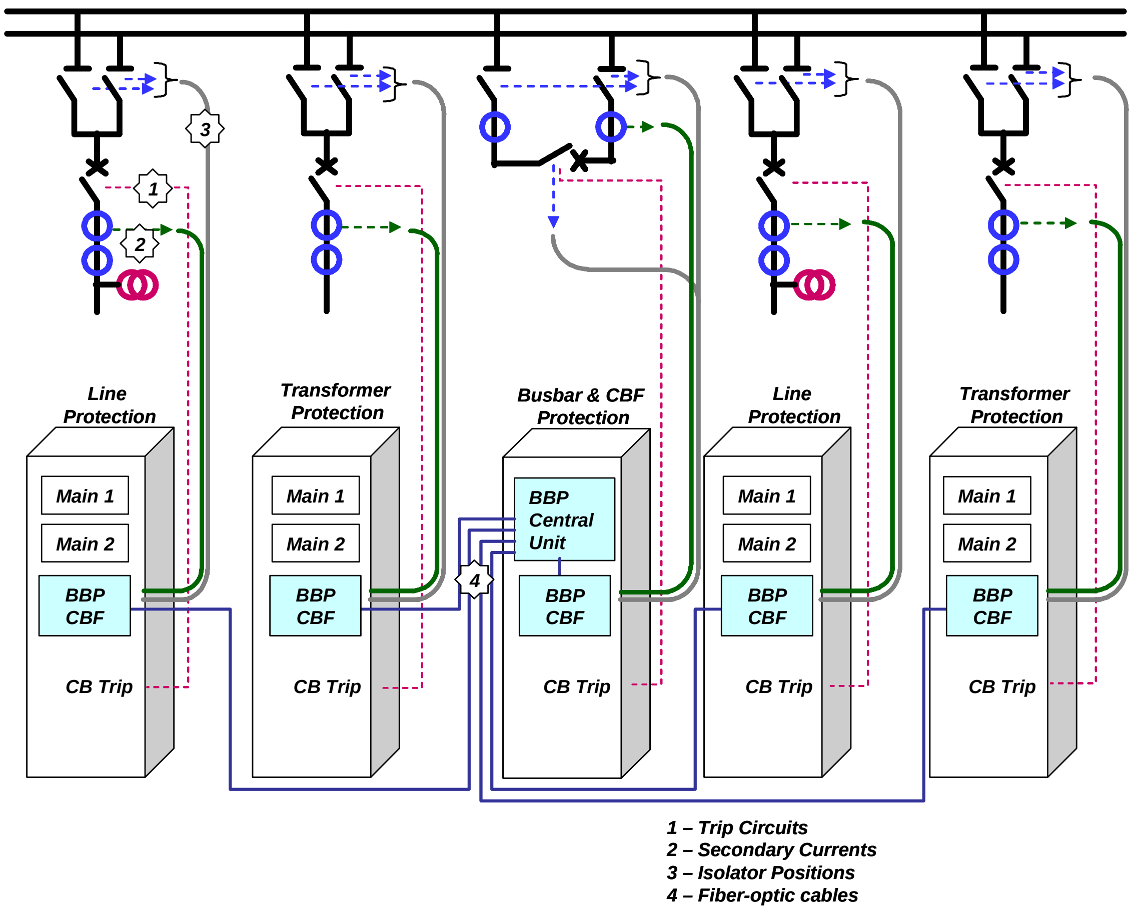


Figure 5-3 Numerical decentralized arrangement

5.2 DC power supply design for busbar protection

The power supply is a very important aspect of busbar protection system design. Its design should take account the desired dependability and selectivity to adapt to the kind of BBP (e.g. whether if it is centralized or decentralized.)

In many cases, modern busbar protection devices are equipped with more functions than just busbar protection.

Several situations can arise, where the risk of losing the busbar protection due to DC loss might occur:

- Maintenance of one station battery
- Damage to one station battery
- Weak station battery
- Short circuit of a DC - circuit
- Interruption of a DC - circuit
- Damage to a power supply module within the protection

5.2.1 Centralized busbar protection

In the centralized BBP system, the protection relay is concentrated in one location within the substation. It is here that all the substation currents are used to perform the differential function, all switchgear status is applied to give the correct current balance to feed the tripping zone logic, and all the circuit breaker failure circuits are concentrated. At the same time all trip circuits to the substation circuit breakers are issued from this location.

In substations where only one BBP exists, the dependability of the system, as explained in the requirements section, is achieved by remote zone 2 which can be unwanted since the fault clearance time is longer, increasing the risk of substation damage, causing transient stability problems and reducing the protection system selectivity. BBP power failure is one cause which requires the action of a back-up protection.

The probability of losing the BBP due to power failure can be reduced by using a battery back-up system. In this case, the protection system is supplied by two batteries and, an auxiliary relay commutes between batteries in case of a battery failure, Figure 5-4 a). To have a BBP out of service due to power failure, both batteries have to fail which is more unlikely to occur, consequently the need of remote zone 2 operations are reduced.

If for dependability of the system the choice is made to duplicate the BBP, it should be accomplished with the use of two independent batteries, Figure 5-4b). If one battery fails, the corresponding BBP will be out of service but the second protection will remain in service. If a duplicated battery system is unavailable then no duplication of the power supply exists and there is no advantage to having two BBPs in case of a power failure; both BBPs will be switched off and remote Zones 2 will have to operate in case of a busbar fault.

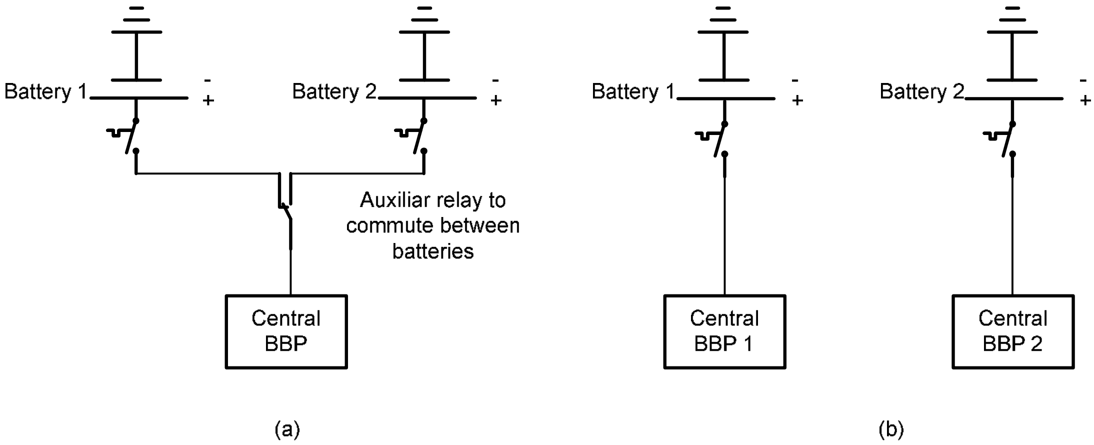


Figure 5-4: BBP central unit power supply (a) Using two batteries (b). By separate batteries

5.2.2 Decentralized busbar protection

In a decentralized BBP there are two power supplies that need to be considered: the central unit power supply and the bay unit power supply. The considerations for the power supply of the central unit are similar to the centralized BBP power supply; for example it can have back-up with a second battery if there is no second BBP.

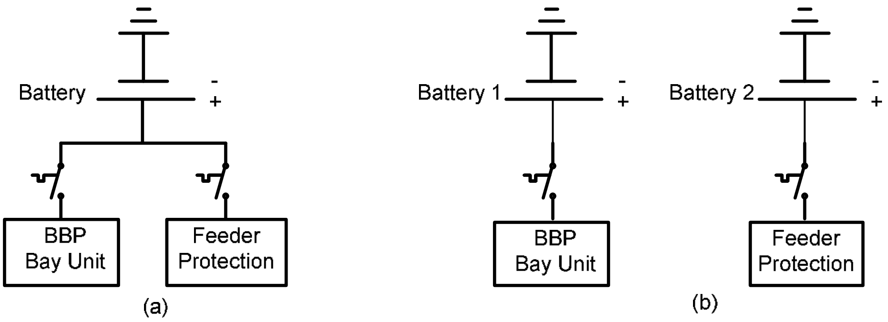


Figure 5-5: Power supply in a bay panel (a). BBP bay unit and feeder protection sharing the same battery (b). BBP bay unit and feeder protection powered supplied by separated batteries

The bay units, which are located in each bay panel, can be powered from the local panel power supply system. In feeder protection systems, composed of one single main protection, both bay unit and the feeder protection can share the battery supply by distinguishing power circuits. It is acceptable to do this if the main protection has no back-up function over the BBP, typically reverse distance zone, Figure 5-5a). If the battery fails, loss of the power supply will shutdown both the BBP and one of its back-up protections, resulting in no advantage of having back-up protection in case of a power failure. In this case, both protections should be supplied using separate batteries, Figure 5-5b).

In feeder protection systems composed of two main protections, these are normally supplied by separate batteries for reasons of redundancy. In this case, the BBP bay unit can be supplied by one of the batteries without compromising its dependability, Figure 5-6.

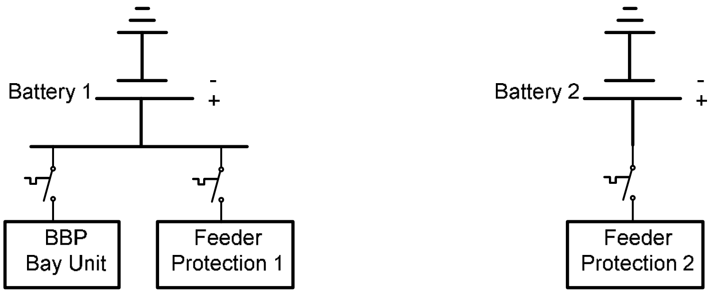


Figure 5-6: BBP bay unit sharing the same battery with one feeder protection.

Special attention has to be taken regarding these solutions. During maintenance of a bay panel by non protection engineers, it is not unusual for station personnel to shutdown all local power supplies and auxiliary voltages before starting their work. This is done for personnel security reasons, but in shutting down the panel the corresponding protective devices will also be shutdown, including the BBP bay unit. If, before this action, the BBP bay unit is not placed in the out of service mode, a BBP alarm and possible blocking will occur.

An alternative to this is to supply each bay unit with the same power supply as the central unit. In this solution, there is a dependency of the bay units and the central unit on the same battery supply. The consequence of losing one BBP element's power supply will lead to the loss of all of the BBP system, Figure 5-7.

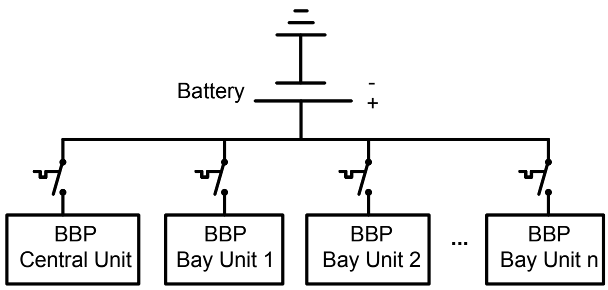


Figure 5-7: Decentralized BBP power supply using one battery.

To increase the overall availability of the BBP system, the power supply system can be designed in one of the following two ways, as shown in Figure 5-7 & Figure 5-8.

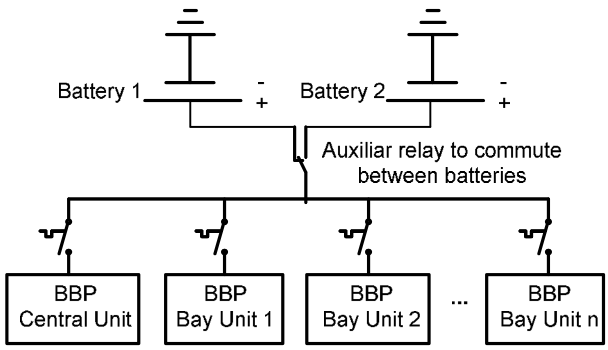


Figure 5-8: Decentralized BBP power supply using two batteries and an auxiliary relay to commute between batteries.

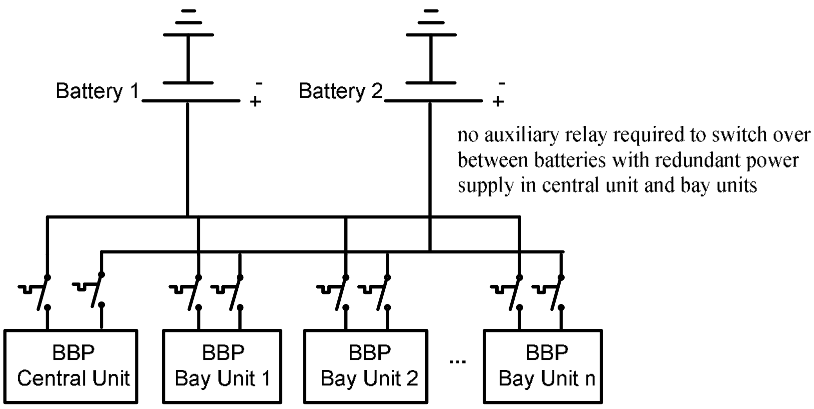


Figure 5-9: Redundant power supplies within the central and bay units of the decentralized BBP.

In many cases, modern busbar protection devices are equipped with more functionality than just busbar protection (e.g. circuit breaker failure, end fault, overcurrent backup protection). In order to achieve a higher availability of the busbar protection system, redundant power supplies in the central and bay units can be used to increase availability.

6 Current Input Signals

This section specifies criteria for conventional window type iron-cored current transformer (CT) selection and introduces electronic current transformers (ECT) as an alternative for future busbar protection system applications.

6.1 Current Transformer Requirements

Short circuit currents at substations may be high enough to cause severe CT saturation, resulting in substantial CT secondary current distortion. Busbar protection systems must be designed to operate reliably under these conditions. It is common that CTs installed in a substation may have different ratings and V-I characteristics. Feeders with low nominal currents may have CTs with a low ratio. In such applications, if the fault occurs adjacent to the CT on its load side such as at location F_2, it can cause severe CT saturation even with symmetrical fault currents (Figure 6-1). Internal faults at the bus (F_1 location) determine busbar protection dependability. External faults (F_2 location) determine busbar protection security and should be considered for each different CT type.

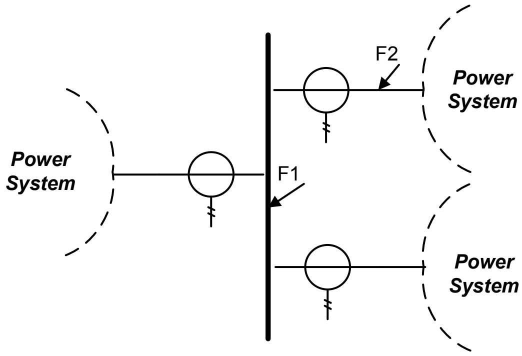
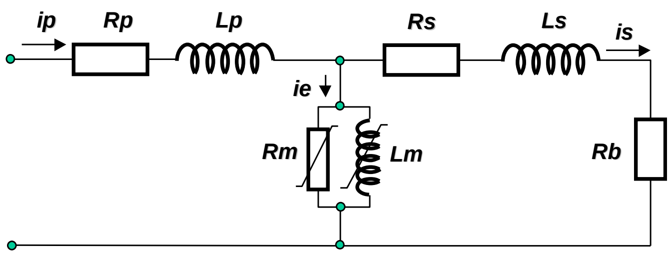


Figure 6-1 Critical Fault Locations for Busbar Protection

Conventional iron-cored current transformer performance characteristics are specified by IEC Standards [1] and [3] and IEEE Standard [16]. The IEEE standard covers current transformer behaviour under steady state and symmetric fault conditions. Three IEEE documents provide guidelines for current transformer selection for different operating fault conditions [24] and [28]. Current transformer equivalent circuit is shown in Figure 6-2.



i_p - Primary current (referred to the
i_s secondary)
i_e - Secondary current
R_p, L_p - Exciting current
- Primary winding resistance and leakage inductance (referred to the secondary)

R_s, L_s - Secondary winding resistance and leakage inductance
L_m - Magnetizing inductance
R_m - Iron loss equivalent resistance
R_b - CT burden including lead resistance

Figure 6-2 Current Transformer Equivalent Circuit

The CT iron-core is a non-linear element that saturates whenever flux inside the CT core exceeds the saturation level, resulting in distorted and reduced secondary current that may cause relay mal-operation. However, a CT cannot saturate immediately upon fault inception. The time that is taken to begin CT saturation is called time-to-saturation. Remanent flux in the CT core can also cause relay mal-operation. To reduce or avoid saturation and/or remanent flux, different current sensing devices have been developed. Figure 6-3 compares V-I characteristics for a non-gapped CT, gapped CT, and Rogowski coils. As shown in Figure 6-3 the CT knee point voltage is specified differently in IEEE and IEC standards. However, a definition of the saturation voltage at which the CT maintains its required accuracy is specified in a similar way as shown in Figure 6-3. Introduction of an air gap in the CT core reduces the CT V-I characteristic slope. This results in a reduced remanent flux, but increases the phase error. Rogowski coils have a linear V-I characteristic. However, they need specially designed relays that accept these types of signals.

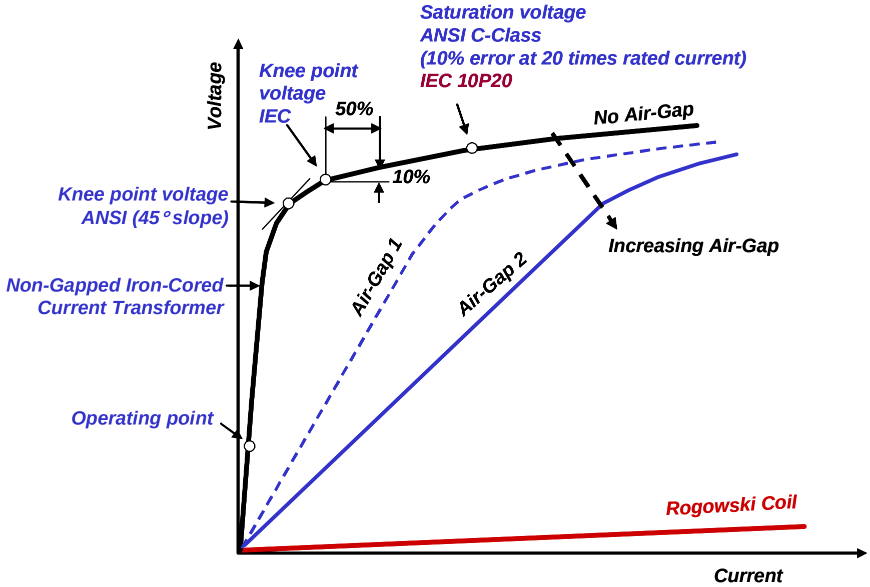


Figure 6-3 Comparison of Current Transformer, and Rogowski Coil V-I Characteristics

CT saturation can be caused by one or more of the combined events listed below:

Symmetric short circuit currents can cause CT saturation if the CT secondary voltage exceeds the saturation level.

Asymmetric short circuit currents can cause CT saturation at smaller current magnitudes compared to symmetric short circuit currents due to the DC component (DC offset).

Remanent flux (remanence) in the CT core reduces the margin for flux increase in one direction and leads to earlier saturation (reduces time-to-saturation) if the fault current creates flux in the same direction as the remanent flux (positive remanence). However, if the fault current creates flux in the opposite direction as the remanent flux (negative remanence) this will extend time-to-saturation. Once a remanent flux is established in a high remanence type CT, very little of it dissipates under service conditions and it will stay in the core until the core is demagnetized. In practice the remanence can vary from 0 to 80% of the saturation flux. A remanent flux will only marginally be reduced by a load current. The load current will only require a flux that is a small fraction of the saturation flux. Therefore, the remanent flux may remain practically unchanged for years. To remove the remanent flux, one method is to saturate the CT core by applying the voltage at the CT secondary winding whilst having the primary winding open. The voltage is increased until the CT saturates then is slowly reduced to zero. The CT data are specified without remanent flux.

Figure 6-4 shows the impact of remanence on a CT without air gap for symmetric and asymmetric 60 Hz fault current 20 times the CT rated current and at rated resistive load (IEEE/ANSI standards and 60 Hz). The secondary current is shown for a remanent flux (remanence) of +80%, 0% and -80% of the saturation flux. Figure 6-4a shows +80% positive remanence reduces time-to-saturation to about 2 ms, while time-to-saturation for 0% remanence is about 5 ms. For -80% remanence nearly no saturation occurs in the first half cycle. Figure 6-4b shows that for 80% positive remanence (in the direction of the DC component) saturation occurs after 3 to 4 ms. For 0% remanence flux saturation occurs after 6 ms and for -80% remanence time-to-saturation is prolonged to about 8 ms.

Figure 6-4 shows the influence of remanence when a CT saturates in the first loop of the fault current. However, for faults with a large DC component a CT may saturate after several cycles. In this case, remanence may cause this CT to saturate in the first loop of the fault current.

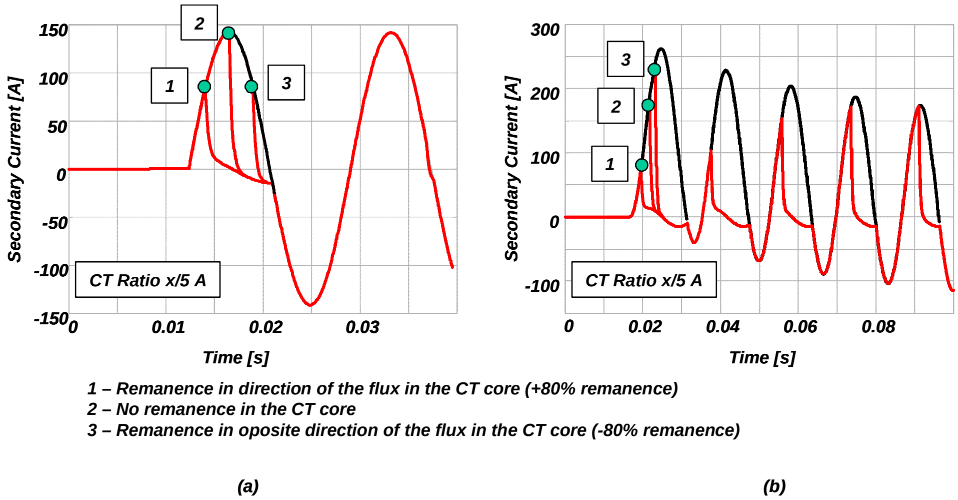


Figure 6-4 Influence of Remanence for Symmetric and Asymmetric Fault Currents

If the iron core of the CT has no air gap a remanent flux may remain after a current interruption. The amount of remanence is dependent on the CT type. Generally there are three different types of CT:

The High remanence type CT has no given limit for the remanent flux. The CT has an iron core without an air gap and the remanent flux might remain for a long time. The remanent flux can be up to 80% of the saturation flux. Typical examples of high remanent type CT are classes P, TPS and TPX according to IEC, classes P and X according to BS (British Standard) and non-gapped classes C and K according to ANSI/IEEE.

The Low remanence type CT has a specified limit for the remanent flux. The magnetic core is provided with small air gaps to reduce the remanent flux to a level that does not exceed 10% of the saturation flux. Examples are Class TPY according to IEC 60044-6, gapped classes C and K according to ANSI/IEEE and class PR according to IEC 60044-1.

The Non remanence type CT has a practically negligible level of remanent flux because of the large air gaps. An example is class TPZ according to IEC 60044-6.

Current chopping. Interrupting a small reactive current can cause current chopping, resulting in an exponentially decaying DC current in the CT secondary circuit and/or excessive switching overvoltages. One example of an exponentially decaying DC current in the CT secondary circuit is shown in Figure 6-5. This secondary DC current results from the stored energy in the CT magnetic core, not from the primary current in the power system. These secondary currents are typically small for shunt reactors and can be ignored when protecting reactors using numerical relays. Generally, current chopping is not pronounced in high voltage systems when interrupting rated currents of shunt reactors.

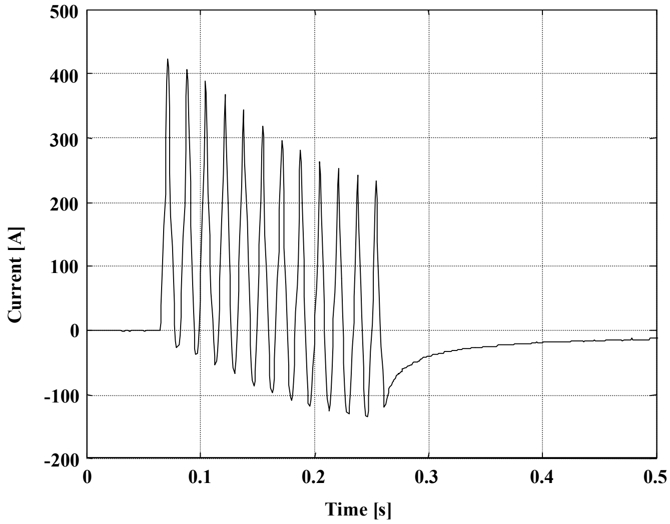


Figure 6-5 Current Chopping when Switching Shunt Reactor

6.2 Criteria for Current Transformer Selection

Theoretically, it is possible to dimension a CT so that it will not saturate under any fault conditions, but this would result in an unreasonably large CT. Busbar protection schemes implemented in modern numerical multifunction relays can tolerate substantial CT saturation, while providing high-speed operation. Manufacturers use different algorithms to achieve relay stability during CT saturation. For internal faults, relays are designed to operate in the presence of distorted waveforms, or prior to CT saturation (time-to-saturation). For external faults, the protection scheme should remain stable for all types of fault for the time needed to clear the fault. For modern numerical protection schemes, a time-to-saturation of several milliseconds may be sufficient to stabilize the protection in case of external faults. Typical operating times for busbar protection are below one cycle. Although modern numerical protection relays can reliably operate if the CT saturates during faults, it is necessary to determine the CT time-to-saturation to verify that the requirements for proper CT selections are met.

During faults the CT secondary voltage V_s will increase depending on the characteristics of the fault current, CT parameters, wiring resistance, and burden. For a symmetric fault current of 20 times the CT rated current and rated burden, V_s will increase to ANSI C Class saturation voltage V_{sat} determined by Equation 6-1.

$$V_{sat} = \frac{I_{Pf}}{N} \cdot R_T = I_{Sf} \cdot R_T \qquad \text{6-1}$$

I_{Pf} - symmetric fault current in the primary circuit (for ANSI C-Class, 20 times the CT rated current)
I_{Sf} - CT secondary current
N - CT ratio
R_T - Total CT resistance that includes the CT secondary winding and burden with lead resistance

For protective relaying applications, the CT saturation voltage V_{CTsat} should be higher than V_{sat} and may be selected using Equation 6-2.

$$V_{CTsat} \geq K_{tf} \cdot K_{rem} \cdot V_{sat} \qquad \text{6-2}$$

K_{tf} - transient factor, defines V_{CTsat} to ensure proper CT transient behavior without remanence in the CT core
K_{rem} - remanence factor, which defines the CT remanence impact on the CT transient behavior during a fault

Factor K_{tf} may be calculated using Equation 6-3 [19], where T_p is the primary system time constant and T_s is the current transformer time constant.

$$K_{tf} = \frac{\omega T_P T_s}{T_P - T_s}\cos[\phi - \arctan(\omega T_P)]\left(e^{-\frac{t}{Tp}} - e^{-\frac{t}{Ts}}\right) + \sin[\phi - \arctan(\omega T_P)]e^{-\frac{t}{Ts}} - \sin\left[\omega t - [\phi - \arctan(\omega T_P)]\right] \quad \text{6-4}$$

Factor K_{rem} may be calculated using Equation 6-5, where ψ_r is remanent flux and ψ_s is saturation flux.

$$K_{rem} = \frac{1}{1 - \frac{\psi_r}{\psi_s}} \quad \text{6-5}$$

Symmetric Fault Currents

For symmetric faults $\phi - \arctan(\omega T_P) = \frac{\pi}{2}$ and K_{tf} can be calculated using Equation 6-6.

$$K_{tf} = 1 - \cos[\omega t] \quad \text{6-6}$$

To avoid CT saturation in the first half cycle $K_{tf} \geq 2$ is needed as shown in Figure 6-6.

If the symmetric fault current is high enough to cause CT saturation, the time-to-saturation can be determined using Equations 6-2 and 6-6, which leads to Equation 6-7.

$$t_{saturation} = \frac{1}{\omega} a\cos\left(1 - \frac{V_{CTsat}}{V_{sat}}\right) \quad \text{6-7}$$

Asymmetric Fault Currents

Assuming that there is no remanence in the CT core (K_{rem}=1) to avoid CT saturation for the maximum DC offset K_{tf} may be defined by Equation 6-8.

$$K_{tf} = \omega \cdot T_P + 1 \quad \text{6-8}$$

Full-offset asymmetric fault current occurs at $\phi - \arctan(\omega T_P) = 0$ and K_{tf} is determined using Equation 6-9. The envelope of Equation 6-9 is obtained for sin (ωt)= -1, which leads to Equation 6-10.

$$K_{tf} = \frac{\omega T_P T_s}{T_P - T_s}\left(e^{-\frac{t}{Tp}} - e^{-\frac{t}{Ts}}\right) - \sin(\omega t) \quad \text{6-9}$$

$$K_{tf} = \frac{\omega T_P T_s}{T_P - T_s}\left(e^{-\frac{t}{Tp}} - e^{-\frac{t}{Ts}}\right) + 1 \quad \text{6-10}$$

Figure 6-6 shows plots for Equations 6-6, 6-8, 6-9 and 6-10, for T_P=20 ms and T_S=10 s. For fast protection where relays are expected to operate in less than one cycle such as for busbar protection Equation 6-9 may be used to estimate the CT time-to-saturation. Equation 6-9 can be simplified by assuming $T_s \gg T_p$, which leads to Equation 6-11. This assumption results in slightly more pessimistic results, but eliminates the need to determine T_s. Equation 6-10 results in considerably higher pessimistic results for times shorter than 12 ms and should be applied only when relay operation time is longer than 12 ms. Equation 6-10 can also be simplified by assuming $T_s >> T_p$, which leads to Equation 6-12. This assumption also results in more pessimistic results, but again eliminates a need to determine T_s. Note: Equation 6-12 is proposed by the IEEE document IEEE Standard C37.110 for the entire range of the relay operation. Equations defining criteria for the transient factor K_{tf} selection are shown in Figure 6-7.

$$K_{tf} = \omega T_P \left(1 - e^{-\frac{t}{T_P}}\right) - \sin(\omega t) \qquad \text{6-11}$$

$$K_{tf} = \omega T_P \left(1 - e^{-\frac{t}{T_P}}\right) + 1 \qquad \text{6-12}$$

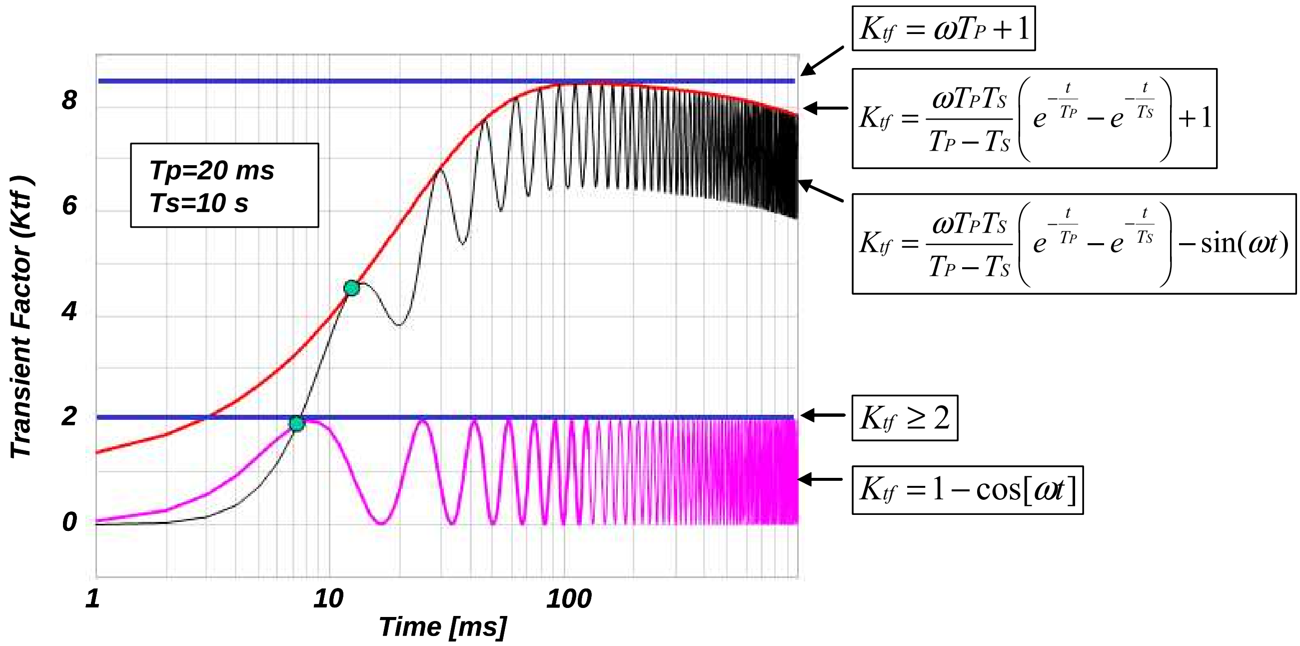


Figure 6-6 Transient Factor Ktf for different Fault Conditions

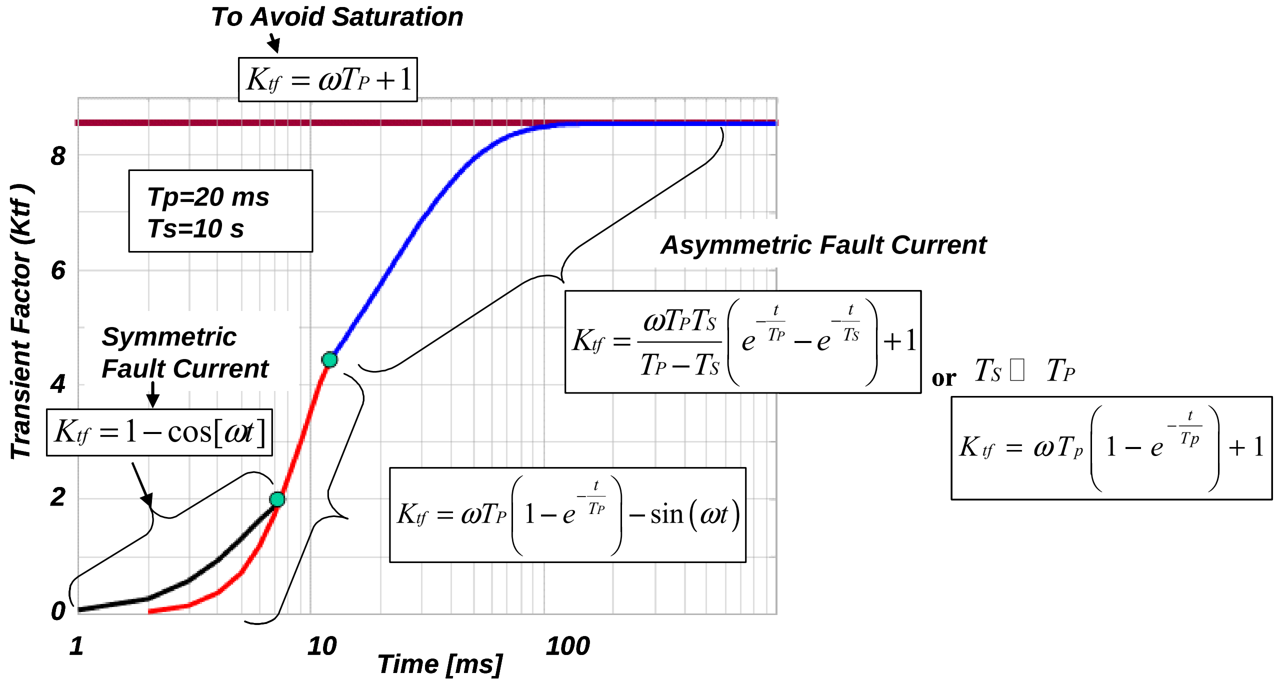


Figure 6-7 Criteria for Transient Factor Ktf Selection

6.2.1 Examples of CT Selections

Time-to-Saturation for a 600/5 A, C100 Current Transformer

Figure 6-8 and Figure 6-9 show CT transient responses for symmetric and asymmetric faults tested in a high power laboratory. The CT saturation voltage was V_{CTsat}=130 V. The CT was tested with no remanence; demagnetized before testing. Figure 6-8 shows the test results at 8 kA, 60 Hz symmetric fault current with R_b =10 Ω. Figure 6-9 shows test results with R_b =1 Ω and R_b =10 Ω at 6 kA full asymmetric fault current and T_p=20 ms. Note that the CT saturates faster for a symmetrical fault than for an asymmetrical fault.

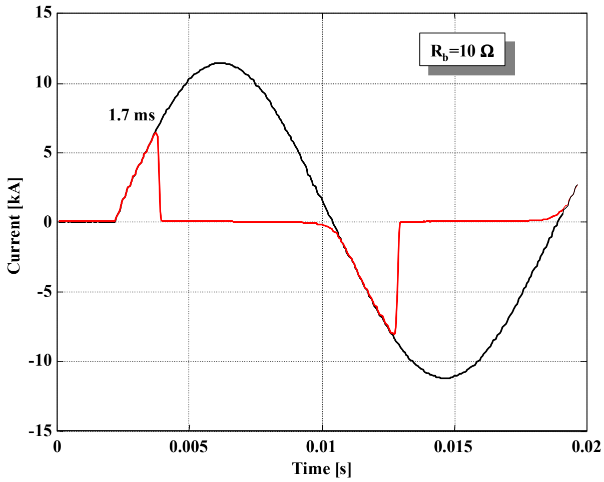


Figure 6-8: 600/5 A, C100, Rb=10 Ω, 8 kA Symmetric Current

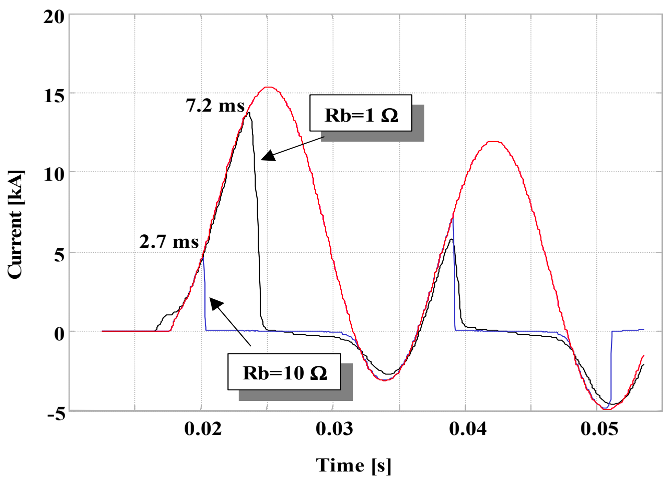


Figure 6-9: 600/5 A, C100, Rb =1 Ω and Rb =10 Ω, 6 kA Asymmetric Current, Tp=20 ms

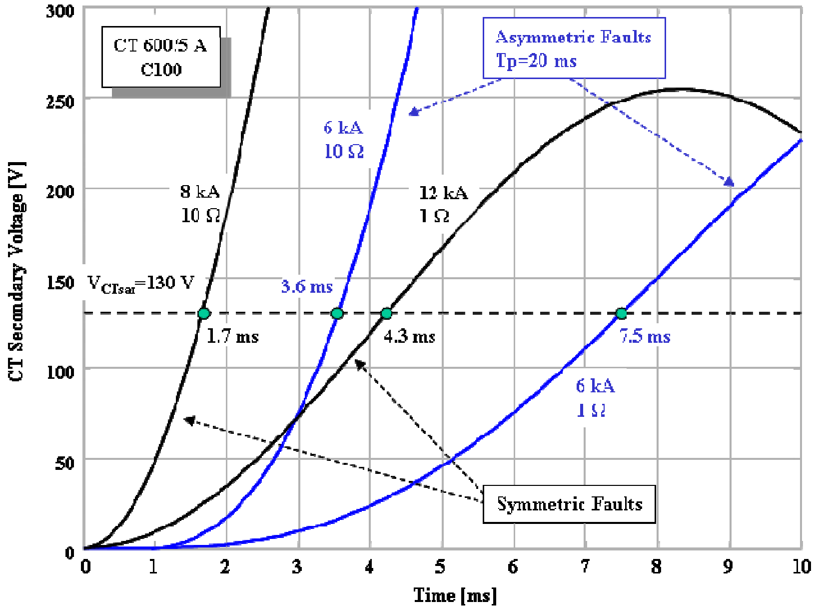


Figure 6-10 Time-to-Saturation for a 600/5 A, C100 Current Transformer

Time-to-Saturation for a 2000/1 A, 30 VA, 5P20 Current Transformer

In a 400 kV substation the minimum required time-to-saturation for a BBP is 3 ms. The current transformer is 2000/1 A, 30 VA, 5P20 with R_{CT} = 6.21 Ω, minimum R_b = 0.3 Ω, and maximum R_b = 2.75 Ω. The CT total burden resistance: minimum R_T = 6.51 Ω, and maximum R_b = 8.96 Ω. The maximum short circuit current in the substation is I_{s_max} = 52 kA.

The CT secondary voltage V_{CTsat} at 20 times rated current and at a rated burden of 30 Ω is $V_{CTsat} = 20 \cdot 30 = 600V$

The CT internal secondary voltage V_s at I_{s_max} and maximum R_T is $V_{sat} = \frac{52e^3}{2000} 8.96 = 233V$.

Since $V_{CTsat} \geq 2 \cdot V_{sat}$ the CT will not saturate at a symmetric fault current of 52 kA.

For asymmetric fault currents the CT will not saturate within 8 ms for all considered fault conditions (see Figure 6-11), satisfying the minimum required time-to-saturation of 3 ms.

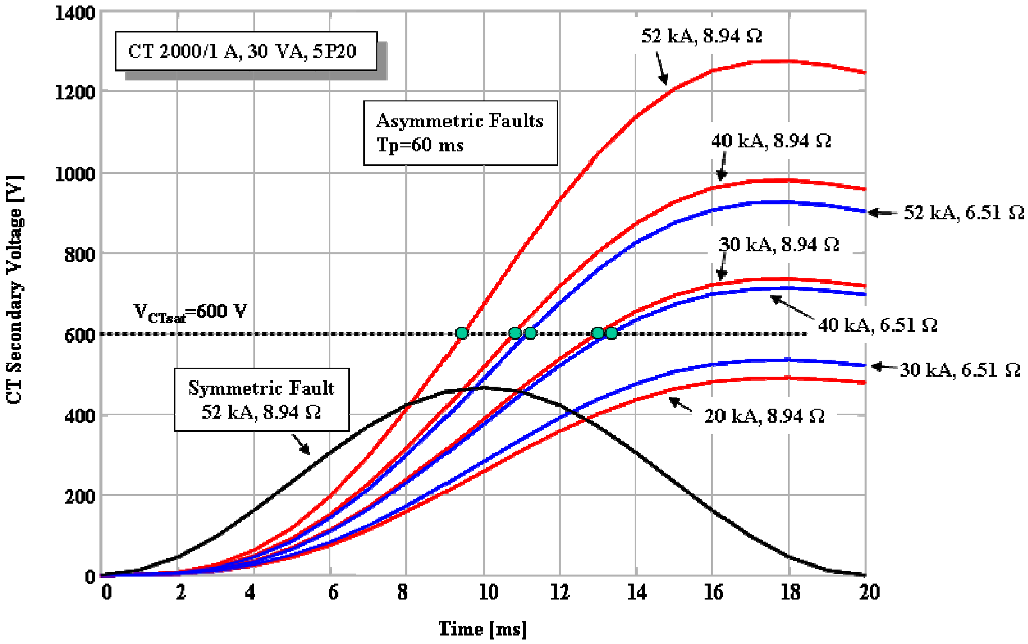


Figure 6-11 Time-to-Saturation for a 2000/1 A, 30 VA, 5P20 Current Transformer

6.3 Electronic Current Transformers

Conventional iron cored current transformers are typically designed with secondary rated currents of 1A and 5A. The primary rated current is adapted to the rated current of the switchgear. Accuracy class, performance and accuracy limit factor are determined by the application of the connected protection and measuring devices. A wide variety of load currents for different feeders, different transient requirements and different applications lead to a large variety of current transformers with separate cores for metering and protection. New generation electronic current transformers (ECT) have performance characteristics that are favourable compared to conventional CTs such as high measurement accuracy and a wide operating range allowing the use of the same device for both metering and protection. However, ECTs are low power sensors and cannot be directly interconnected with conventional equipment. They need microprocessor-based equipment designed to accept signals from ECTs such as: Rogowski coils, Low power iron-cored current sensors, and Optical current sensors. IEC and IEEE standards specify requirements for ECTs [5] and [16].

Common performance characteristics for ECTs include: output signal is a voltage (milli-volt range at rated current); high short-circuit current withstand ratings; galvanic isolation from the primary conductor; no environmental hazards (oil and SF6 free); safe for personnel (no open secondary high voltage hazard, no violent failures such as with oil insulated CT); immune to EMI (shielded).

6.3.1 Rogowski Coils

Rogowski coils consist of wire wound on a non-magnetic core (μ_r=1). The coil is placed around the conductor whose current is to be measured. If the core has a constant cross-section (S) and the wire is wound perpendicular on the middle line with constant density (n), then the voltage induced in the coil is defined by Equation 6-12, where M is mutual coupling inductance. For an ideal Rogowski coil, M is independent of the conductor location inside the coil loop.

$$v(t) = -\mu_0 \mu_r n S \frac{d}{dt}[\sum_j i_j(t)] = -M \frac{d}{dt}[\sum_j i_j(t)] \quad (6\text{-}12)$$

A Rogowski coil output signal is a scaled time derivative *di/dt* of the primary current. To use such signals with phasor-based protective relays, signal processing is required to extract the power frequency signal. This may be achieved by integrating the Rogowski coil output signal, or by using a non-integrated Rogowski coil output signal. The integrated output voltage is proportional to and in phase with the measured current. Signal integration may be performed within the relay (by using analogue circuitry or digital signal processing techniques) or immediately at the coil location. When using a non-integrated signal it needs to be scaled by magnitude and shifted by 90°.

To prevent the influence of nearby conductors carrying high currents, Rogowski coils are designed with two wire loops connected in electrically opposite directions. High precision Rogowski coils may be designed using printed circuit boards, which contain imprinted windings. Rogowski coils can be designed with different shapes to accommodate the application; for example, circular, oval or rectangular. Rogowski coils can also be designed in a split-core style for installation without the need to disconnect a primary or secondary conductor. Connections to relays can be by wires or through fibre-optic cables. A Rogowski coil equivalent circuit is shown in Figure 6-12. The burden Rb is typically higher than 50kΩ to minimize the impact on the sensor accuracy.

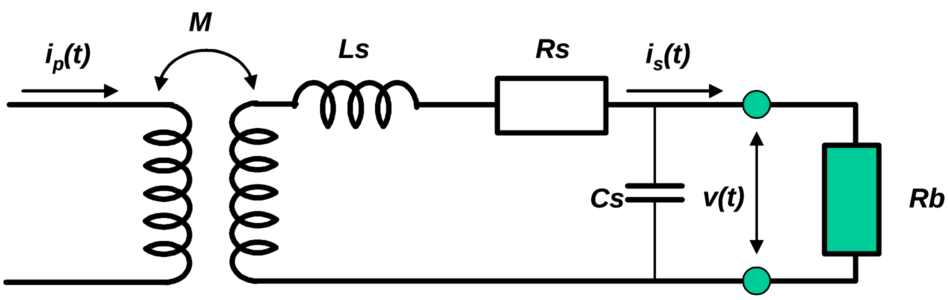


Figure 6-12 Rogowski Coil Equivalent Circuit and Vector Diagram

M	Mutual coupling
L_s	Winding leakage inductance (can be neglected for power applications)
R_s	Secondary winding resistance
C_s	Stray capacitance (can be neglected for power applications)
R_b	Burden

6.3.2 Low Power Iron Core Current Sensors

Low power iron-core current sensors have similar designs to conventional CTs but employ a minimized iron core, resulting in a reduced size and weight. The equivalent circuit is shown in Figure 6-13. Reduction of the core size is possible since new protective relays are designed to accept low power signals (milli-volt range). Resistor R_{CT} (1Ω - 2 Ω) is connected internally across the output terminals, producing an output voltage directly proportional to the current. The burden R_b is typically higher than 10 kΩ to minimize the impact on sensor accuracy. Because of the iron core, they can saturate in a similar manner to a conventional CT, which must be considered when selecting these sensors.

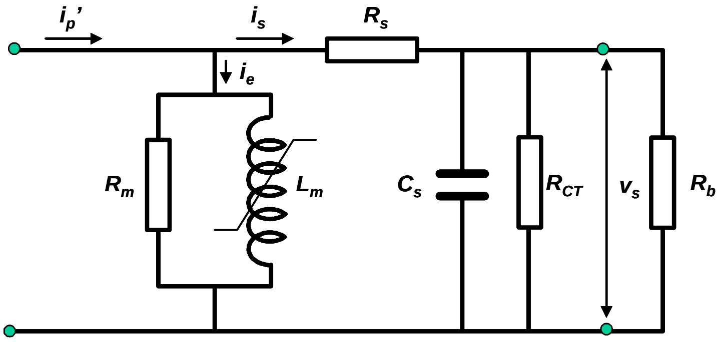


Figure 6-13 Equivalent Circuit of the Low Power Iron Core Current Sensor

i_p'	Primary current (referred to the secondary)	R_m	Iron core loss resistor
i_s	Secondary current	L_m	Non-linear magnetizing inductance
i_e	Exciting current	R_s	Secondary winding resistance
v_s	Secondary voltage	C_s	Stray capacitance
R_{CT}	Internal resistor	R_b	Burden

6.3.3 Optical Current Sensors

Optical current sensors operate on the principle of the Faraday rotation effect using a monochromatic (single frequency) light source. Current flowing in a conductor creates a magnetic field, which rotates the plane of polarization of light travelling in optical fibres encircling the conductor proportional to the current flowing in the enclosed conductor.

A typical optical current sensor system consists of an optical sensor, installed at the high voltage level, embracing the primary conductor. The interface between the sensor and the electronic module in the control/relay room is over optical fibres that additionally provide insulation from the high voltage and prevent induced voltages in the secondary system. The optical signal may be converted to a low-power electrical signal, for use with low power equipment or amplified for use with conventional equipment.

6.3.4 Applications of ECT for Busbar Protection

The ECT output signal is a voltage and requires specially designed relays. For differential protection of busbars ECTs are connected in a voltage-differential circuit. Differential voltage can be obtained by analogue or digital summing of secondary voltages of all ECTs protecting a bus. Designs that use analogue signal summing need only one relay and one input channel to connect the differential voltage. Designs that use digital signal summing inside the relay may use one relay with multiple channels or dedicated relays interfaced by communications.

6.4 Dedicated or shared CTs

In a typical substation, power apparatus such as power lines, transformers, and capacitor banks are connected to the substation bus through bays. Each bay may also include conventional or non-conventional CTs and VTs for control and protection functions.

Further, each bay may have different protection functions implemented in one or several protection relays to cover a protection zone. Ideally, no part of the substation or network should be unprotected; therefore, protection zones are close to one another or preferably overlap. To achieve this, different protection functions covering different protection zones may require measuring the same voltage or the same current. This situation may also occur when control and protection equipment use the same CTs and/or VTs. In many countries it is common that BBP shares the same CTs with line distance protection and transformer differential protection.

Classical CTs are built with several cores that may have different magnetising characteristics. Typically, two CT core types exist: metering and protection. Metering core is used for control and measurement. It has high accuracy under normal operating conditions, but poor performance during faults. Protection cores are designed to provide adequate accuracy during fault conditions.

Electromechanical relays represent high burden for CTs during faults; therefore, to avoid CT saturation each relay may require separate protection CT cores. A further reason for different CT cores is to achieve independent protection schemes. Today, new digital relays represent low burden for CTs. Both dependability and security of the scheme may be achieved by sharing CTs. This solution is less expensive and requires less space which is an important issue for substations such as GIS. However, sharing CTs may not be justified if desired dependability and security cannot be achieved.

The dependability of a protection system is important in terms of its back-up function and with the risk of its failure to correctly clear a fault. A BBP system can share the same CT core with other protection devices, if they are not back-up for each other. This is because an erroneous CT secondary current may affect proper operation of both protection systems connected to the same CT core. As a result a larger non-selective tripping by remote protections may occur. These considerations are also applicable for the security of the BBP as explained in Section 4.6.2.

Different protections which do not provide back-up for each other can share the same CT core. If a BBP has no back-up protection from remote Zone 2 protections and the local distance protections are used for this purpose by using their reverse zones, the BBP should not share the same CT cores with these local distance protections.

On the other hand a differential transformer protection has a protection zone that does not overlap the BBP zone. In this case, it should not be a problem for the transformer protection to share the same CT core with the BBP, Figure 6-14.

Other specifications have to be considered when deciding to dedicate or to share the CT core. When a CT core is to be shared by more than one protection if it is not properly designed it is impossible to perform maintenance work on one device without interfering with the others. With regard to a particular CT current it must be possible to easily isolate a protection from the CT circuit leaving the other protections connected and in service. If this is not catered for, a high risk of unwanted trips or unwanted blocking of functions due to current supervision during maintenance exists.

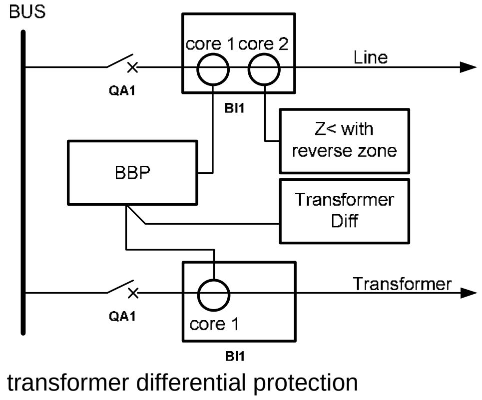


Figure 6-14: Shared CT by BBP and transformer differential protection

7 Busbar replica

7.1 Need for isolator replica

CT secondary circuits from every bay in the station are connected to the busbar protection. Therefore for more complex station layouts when one bay can be connected to more than one differential zone (e.g. double busbar-single breaker station as shown in Figure 4-2 it is necessary to provide a logical scheme, which dynamically links individual bay currents to the appropriate differential measuring zone. Information with respect to which bay current shall be connected to which differential measuring system is typically derived from the status of the busbar disconnectors. Thus, this logical scheme must at least take the status of all busbar disconnectors into account.

Selective tripping for busbar protection is also mandatory in order to limit the extent of a busbar protection operation for an internal fault. This means that only the circuit breakers connected to the faulted bus section shall be tripped. In a multi-bus zone configuration each bus zone is therefore protected by a dedicated “differential measuring system”. Thus, this tripping scheme must also take into account the busbar disconnector status. Sometimes even the status of other devices (e.g. transfer disconnector) must be taken into account as well.

The logical scheme, which provides dynamic CT linking and breaker dedicated tripping signal is often called dynamic bus replica.

For analogue differential relays such logical schemes have been traditionally arranged in one of the following two ways:

- by directly using busbar disconnector auxiliary switch contacts to physically switch the CT secondary circuits and route back the individual differential protection zone trip signals to associated circuit breakers. Note that these contacts may be specifically designed for such duty.

- by using busbar disconnector auxiliary switch contacts to operate auxiliary (bi-stable) relays, whose contacts are then used to physically switch the CT secondary circuits and route back the individual differential protection zone trip signals to associated circuit breakers

With modern numerical busbar differential relays it is possible to provide such a logical scheme in software without the need for any physical switching in the CT secondary circuits or the circuit breaker trip circuits. Simply, the status of the auxiliary switch contacts from every relevant switchgear object in the substation is connected to opto-coupler inputs of the busbar protection relay. The numerical busbar protection relay will then evaluate the switchgear object status and assign the measured individual bay currents to the relevant zone in software. Accordingly, the trip signal from the assigned differential protection zone is automatically routed back to the dedicated bay trip output contact in order to directly trip the bay circuit breaker.

7.1.1 Feeders of multi busbars

In order to limit the extent of a shut-down the selectivity of a busbar protection is mandatory. In a multi bus zone configuration each bus zone is therefore protected by a dedicated “measuring system". In numerical BBP schemes this is usually processed by software. The information with regard to which feeder actually has to be considered in a measuring system is derived from its disconnector position. Modern BBP schemes monitor the disconnector auxiliary switch contacts using binary inputs and dynamically create the busbar replica accordingly.

7.1.2 Need for line disconnector position

Normally the line disconnector is not relevant for the dynamic bus replica. When an earthing switch is located between the CT and busbar as per the example for the parallel lines shown in Figure 7-1 the line disconnector position becomes important. If one line is out-of-service and earthed, a fault current in the live line can induce a considerable current in the earthed feeder. To avoid this current being seen as a false differential current when QB1 is closed, the open line disconnector status has to be processed within the BBP to avoid spurious tripping. There are other examples which can cause the same problem such as discharge of HV cables.

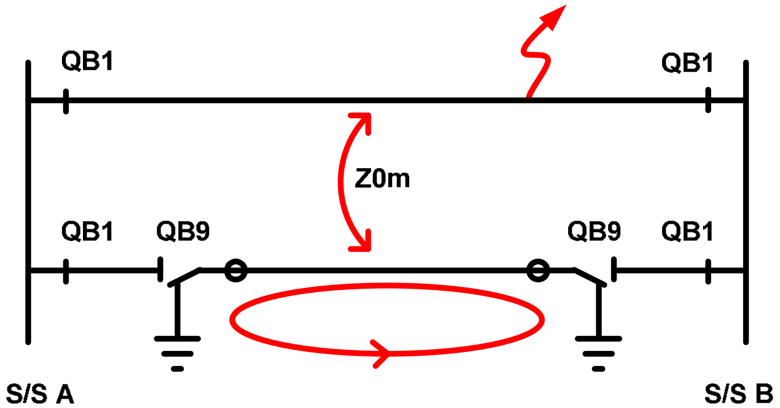


Figure 7-1: Induction of current in a dead parallel line

7.1.3 Bus sectionalizer

Large buses can be split into several sections by bus sectionalizers. In order to provide maximum selectivity the position of bus sectionalizers has to be recorded as well. Special measures are necessary to form a new, "common" measuring system for the case of closed sectionalizers. In modern BBP schemes the fully static design is advantageous as no switching of currents is necessary. If CTs are available in the sectionalizers a selective measurement for the detection of the faulted section will be possible, however the trip has to be issued to both adjacent bus zones while the sectionalizer is closed.

7.1.4 Bus coupler / sectionalizing coupler

Couplers (bus couplers or sectionalizing couplers) are used to offer a wide range of operational flexibility. Schemes with one or two CTs are common; see Figure 4-1 and Figure 4-2 Dependant upon the arrangement the treatment of a fault in the so called dead zone or blind zone (the stub between the CT and the circuit breaker) is different. The behaviour of the BBP is optimised based upon the record of the CB position and the command to the closing coil. Please refer also to Section 9.4.

7.2 Auxiliary contact requirement and evaluation

7.2.1 Standard contact requirements

The position of the disconnectors is typically obtained via two auxiliary switch contacts on the primary apparatus.

The first auxiliary switch contact indicates that the primary device is closed. In protection literature it is called by several different names as stated below:

- Normally open auxiliary switch contact
- “a” contact (i.e. 52a)
- “closed”

The second auxiliary switch contact indicates that the primary device is open. Again, in protection literature it is called by several different names as stated below:

- Normally closed auxiliary switch contact
- “b” contact (i.e. 52b)
- “open”

Typically both auxiliary contacts are used to provide position indication and supervision for busbar protection.

7.2.2 Minimum contact requirements

The minimum requirement for the busbar replica is to monitor the position of the disconnector using just one auxiliary contact, either NO or NC type. However, using a pair of auxiliary contacts, representing the OPEN and CLOSED position, offers additional functions that can improve the reliability of the bus replica including some supervision possibilities.

7.2.3 Requirement and evaluation of some BBP schemes

In practice different logic schemes can be found. The following two logic schemes are often used in conjunction with disconnector auxiliary switch contact supervision within modern numerical busbar protections.

Scheme 1 “If not OPEN then CLOSED”

As the name of the scheme suggests, only when the auxiliary contacts signal the clean open position (“normally open auxiliary (NO) contact input” = inactive and “normally closed auxiliary (NC) contact input” = active), the disconnector is taken to be open. For all other signal combinations the disconnector is considered to be closed. This scheme does not pose any special requirements to auxiliary switch contact timing. The only requirement is that the disconnector NC contact must open before the disconnector main contact is within arcing distance.

The time during which the OPEN and CLOSED signal inputs disagree (i.e. both binary inputs active or both inactive) is monitored by the isolator supervision function. The maximum time allowed before an alarm is given can be set according to disconnector timing.

Scheme 2 “Closed or open if clear indication available otherwise last position saved”

As the name of the scheme suggests, only when the auxiliary contacts signal either the clean OPEN or clean CLOSED position is the disconnector considered to be open or closed respectively. However, this poses the stringent requirements on the auxiliary contacts that the CLOSED signal must become active within a certain time (>150ms) before current starts flowing e.g. through arcing. Otherwise this current will not be taken into account in the protection function and this can result in a mal-operation. Therefore, proper timing of the two auxiliary contacts is definitely required; refer to Figure 7-2 and Figure 7-3.

The time during which the OPEN and CLOSED signals disagree (i.e. both binary inputs active or both inactive) is monitored by the isolator supervision function. The maximum time allowed before an alarm is given can be set according to disconnector timing.

The following table and figure summarize the properties of these two schemes.

Table 7-1: Behaviour of scheme 1 and 2

Disconnector status	Undefined	Open	Closed	Undefined
NO aux contact status ”closed” or “a” contact	0	0	1	1
NC aux contact status ”open” or “b” contact	0	1	0	1
Scheme1 internal disconnector status	Closed	Open	Closed	Closed
Scheme2 internal disconnector status	Last Position Saved	Open	Closed	Closed
Alarm timer running	Yes	No	No	Yes

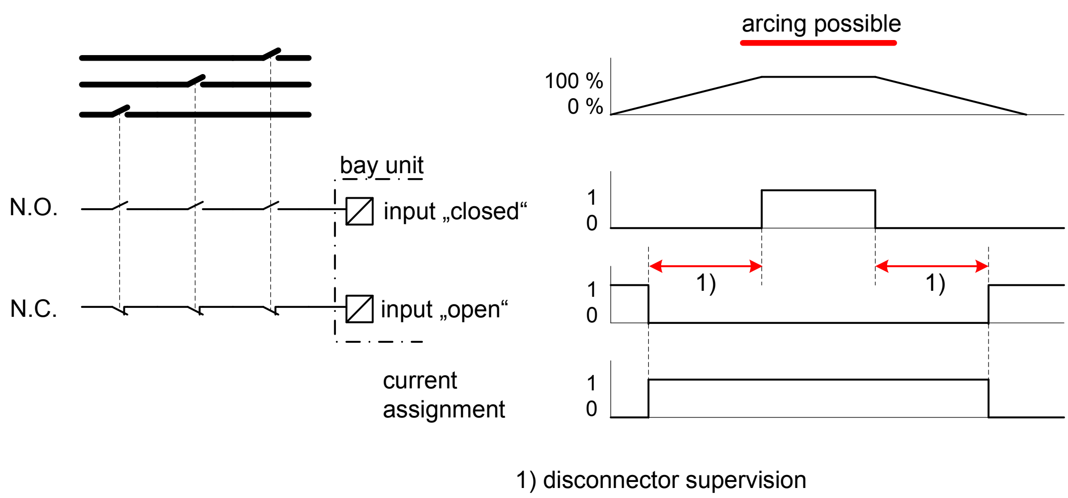


Figure 7-2 Scheme 1

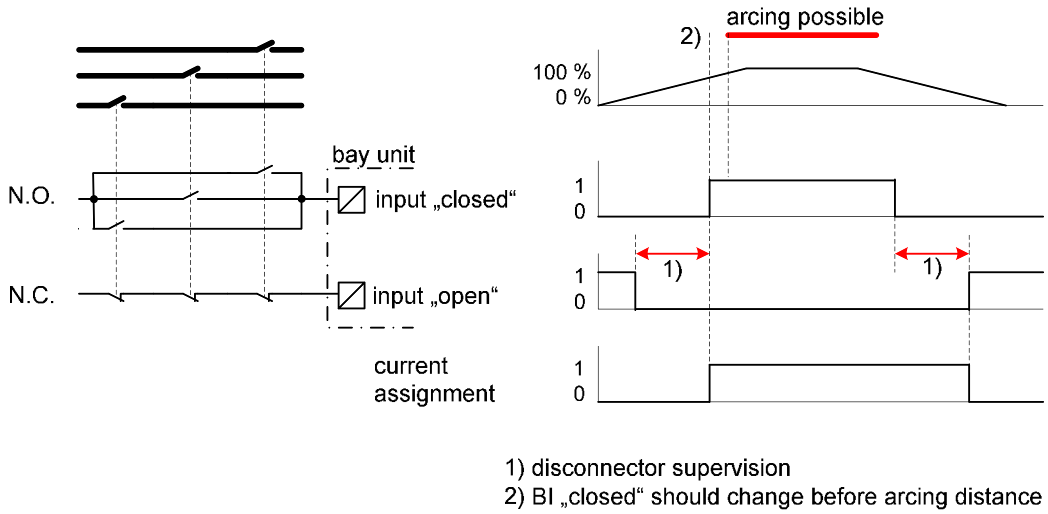


Figure 7-3 Scheme 2

7.3 Circuit breaker replica

The circuit breaker position from a feeder shall be provided at the busbar protection when the position of this particular breaker can improve the operation of the busbar protection. A typical example might be dead zone protection (see Section 9).

7.3.1 Dead zone and End fault protection

Basically the measuring range of a BBP is limited by the CTs. However, by also monitoring when the CB is in the open position for a feeder or a coupler the stub between the CT and the CB can be protected as well. This function is called dead zone and end fault protection (see Section 9).

7.3.2 Auxiliary contact requirement and evaluation

Circuit breaker position is typically obtained via two auxiliary switch contacts. The first auxiliary contact indicates that the primary device is closed. In protection literature it is called by several different names as stated below:

- Normally open auxiliary switch contact
- “a” contact (i.e. 52a)
- “closed”

The second auxiliary switch contact indicates that the primary device is open. In protection literature it is called by several different names as stated below:

- Normally closed auxiliary switch contact
- “b” contact (i.e. 52b)
- “open”

Typically both contacts are used to provide position indication for busbar protection. However, it is possible to use only the normally closed auxiliary switch contact for busbar protection as an alternative.

When the CB changes its position from open to closed, the BBP needs to reassign the corresponding bay current to its protection zone(s) prior to primary current flow. To achieve this the CB close commands shall be available to the BBP. These include, for example, local close commands, close commands from remote control systems, the station automation system or from auto-reclosure schemes. The simplest way of doing this is to take the CB close signal directly from the circuit-breaker closing coil.

The evaluation of the CB auxiliary switch contacts is similar to that for the disconnectors. The supervision is also similar. In addition, the close command can be supervised and cross-checked against the steady states, OPEN and CLOSED. Special attention should be paid to the undefined state of the CB auxiliary contacts. The response of the supervision should always tend towards the safe state of the related function in order to prevent false tripping. For example the end-fault protection must be blocked.

7.4 Failure of dc power

The correct functioning of a BBP is dependent upon the disconnector replica being correct which itself requires a DC supply for the acquisition of the auxiliary contact status. Different methods are available to detect the absence of auxiliary power. Usually the replica works using the last position in such a case.

8 Circuit Breaker Failure Protection

8.1 Working Principle

The Circuit Breaker Failure Protection function, CBF protection, is a local back-up protection function which will operate in the event of an unsuccessful attempt by a circuit breaker to interrupt fault current.

Several types of CBF protection schemes exist and are explained in IEEE Std C37.119-2005. The simplest scheme relies upon the occurrence of two signals during a specified time: an external start and an overcurrent condition or a CB contact information. The external start is typically triggered by a trip command to the circuit breaker from any protection function. For example in a line feeder this can be the trip from a distance relay, in a power transformer feeder this can be a trip command from a differential relay and for any feeder connected to a special busbar this can be from a BBP relay.

The overcurrent relay confirmation is used as the main criteria for the extinction of the circuit breaker through current. It can also be used for security in case an unwanted start signal appears, normally in testing procedures. For feeders with weak infeed it is common to use the circuit breaker auxiliary open contact 52a instead of current base confirmation.

The time delay is established according to stability network demands and is an important factor when coordinating with remote back-up protections.

Different consequences can result from the output of this scheme: a re-trip function, a back-up trip function and intertripping.

8.1.1 Remote Backup

Assume that there is no circuit breaker failure protection and a fault occurs in Line 1 as shown in Figure 8-1. Relays Ar1 and Br1 will see the fault and send trip commands to their corresponding circuit-breakers A-QA1 and B-QA1. If for example, circuit breaker A-QA1 fails to interrupt the fault current, local circuit-breaker A-QA4 and remote circuit-breakers B-QA2 and C-QA1 will open on command from the back-up protections, typically from their distance relays Zone 2 or Zone 3. However, if generator A provides a weak infeed, circuit-breaker A-QA4 may not open since the current can be below back-up protection threshold. In this case, only the generator protections such as over-frequency or current unbalance protection function might operate and the fault would be cleared by the generator shutdown. Breaker A-QA5 will not trip because the transformer TR2 is feeding a passive load.

As a result, the fault would be cleared in remote back-up time and all lines and transformers would be switched out — shutting down the entire power system represented in Figure 8-1.

A solution to this problem is to use Circuit Breaker Failure protection.

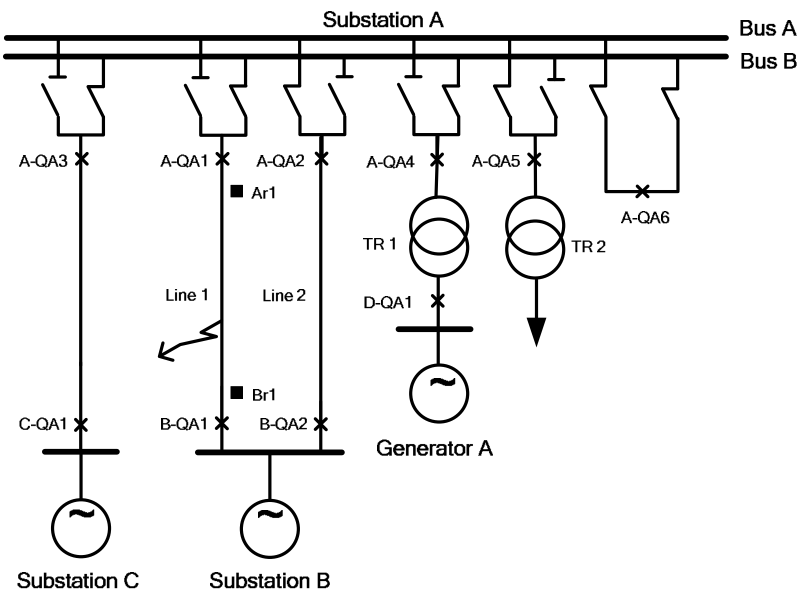


Figure 8-1: Example of a Power System

8.1.2 Circuit Breaker Failure Action

If there is a Circuit Breaker Failure Protection System in the substation then, for the same event, a back trip command will be sent by the A-QA1 CBF protection in order to trip circuit-breakers A-QA3, A-QA4 and A-QA6 shutting off busbar B. In this case, the CBF protection would avoid the tripping of all remote line breakers preventing line 2 and line 3 to be placed out of service. Also transformer TR2 will continue to operate normally.

The fault clearance time is also reduced since, to coordinate with remote relays zone 2, the CBF protection operation time has to be shorter. In Figure 8-2, it is represented by the time chronology for the CBF protection.

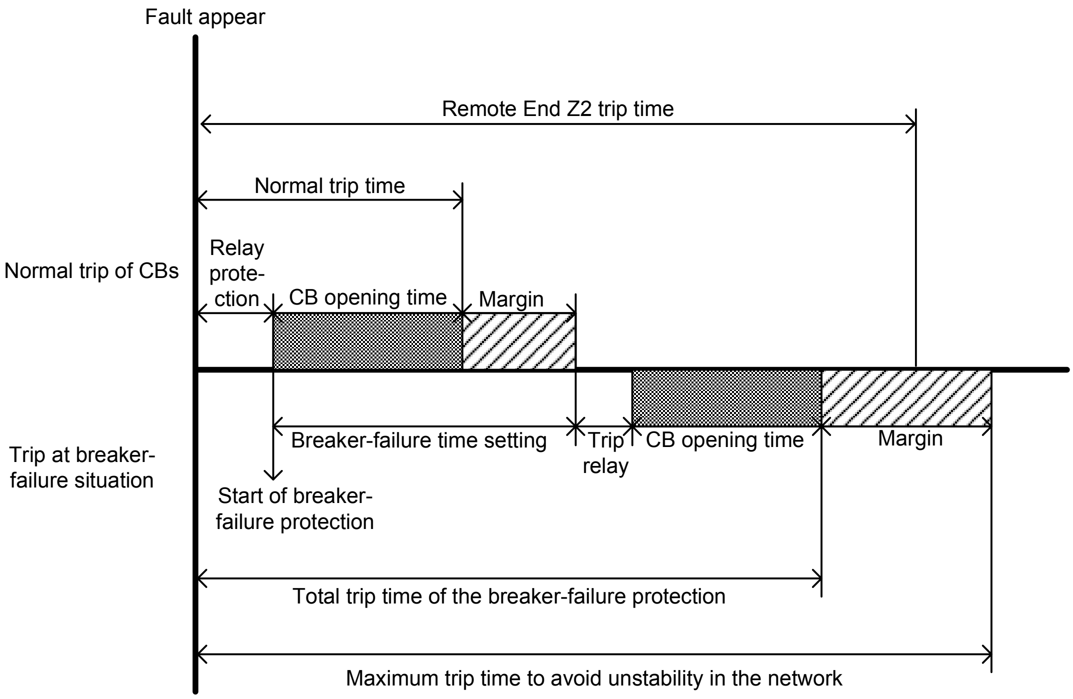


Figure 8-2: Time chronology for Circuit Breaker Failure Protection.

Taking the case of a busbar fault, as an example, in Substation A Busbar B, the BBP will clear the fault by sending a trip command to all connected feeder circuit breakers. Therefore, the busbar fault will be cleared by the trip of A-QA1, A-QA3, A-QA4 and A-QA6 circuit-breakers.

In the event that circuit breaker A-QA4 fails to clear its fault current contribution, another protection on the other side of the transformer will open D-QA1 circuit breaker. In this case the fault could be interrupted by the power transformer phase over current relay.

If A-QA4 CBF protection exists, in this situation, a trip command will be sent to A-QA1, A-QA3 and A-QA6 circuit-breakers and a transfer-trip will be sent to D-QA1 circuit-breaker. The A-QA1, A-QA3 and A-QA6 circuit-breakers have already been tripped by the BBP but they will be re-tripped once more by CBF relay (if retrip is enabled) since the CBF protection does not know which circuit breakers were open. Again, the fault clearance time has to be inferior to the phase over current relay operating time.

8.1.3 CBF protection Re-trip

There is the possibility of having a re-trip function in the CBF protection. The re-trip function has mainly two purposes:

- Protection against personnel errors during relay testing. If a bay protection is tested by means of secondary voltage and current injection, the trip circuits from this protection are normally opened. If the bay protection is used to initiate the CBF there is a risk that test personnel may forget to isolate the start signal to the CBF. If the protection under test trips and there is sufficient load current flowing through the circuit breaker, there is a risk of a back-trip command being issued to trip all back-up circuit breakers. This might cause a severe disturbance. With the re-trip function the consequence of such an error will be limited to the tripping of only one CB.
- To repeat the trip command to the same circuit breaker via separate trip coil and cable.

When the protection has received a start signal a second attempt to trip the main circuit breaker can be made. If the start signal was a single pole start, the re-trip will also be a single pole trip to the main circuit-breaker. If the start signal was a general three phase start, the re-trip will also be a three pole trip to the main circuit-breaker. The re-trip function can have a selected delay, although as short a time as possible is normally required. There is the possibility to have re-trip with current check or unconditional re-trip. If re-trip with current check is chosen, re-trip is only performed if there is current flowing through the circuit-breaker.

8.1.4 CBF tripping of adjacent and remote circuit breakers

If a circuit breaker has failed to clear a fault following operation of a trip relay and if the subsequent re-trip has been unsuccessful - should this optional feature have been selected - then, at the expiration of a time delay the CBF current check relay will issue a back-trip command to initiate tripping of all other circuits connected to the same busbar. Issue of the back-trip command and receipt of back-tripping signals by individual circuit breakers is affected through the busbar replica.

Where the protection system is associated with a feeder circuit breaker, an initiation may also be provided to send an intertrip signal to directly connected remote circuit breaker(s).

In the previous example of a busbar fault and a non opening operation from A-QA4 (see Figure 8-1), a transfer-trip to the D-QA1 circuit breaker from the other side of the power transformer was needed to clear the fault.

8.1.5 Interaction with other protection (OHL AR blocking)

Busbar and CBF protection trips shall also block auto-reclosing in all OHL feeders connected to the faulted bus.

8.2 Implementation

The CBF protection and the BBP have in common the use of a trip circuit logic which selects all the circuit breakers needed to clear the fault. CBF protection selects the back-up circuit breakers to trip. The BBP selects the busbar protection zone circuit breakers. With the exception of the transfer-trip commands, the logic for both trip circuits is identical for the same circuit breaker. Situations exist where BBP trips can send transfer-trip commands to remote ends, these are explained in Section 5 and Section 10.2.

It is easy to see that the security and selectivity requirements for the CBF protection function are similar to the BBP requirements. An unwanted trip will result in tripping the affected zone.

To implement a CBF protection scheme in a substation two things must exist: a CBF relay associated with each circuit breaker in the substation and trip circuit logic. The CBF relay itself can be designed to either measure the current which flows through the circuit breaker or evaluate the status of a circuit breaker auxiliary switch contact.

When the current is measured the relay simply checks that the current is interrupted after a pre-set time when the trip command has been given to the circuit breaker. In addition the relay can be designed to have a faster response time for multi-phase faults which are more of a threat to power system stability than phase-to-ground faults.

When the auxiliary switch contact status is used the relay checks that the open CB position indication is received shortly after the trip command has been given to the circuit breaker. This operating principle is used when sufficient operating current might not be present during circuit breaker tripping (e.g. operation of power transformer over-excitation protection).

The CBF relay is normally placed in each bay panel and, as explained, can have an over current function and a starter input connected to all protection trips to the corresponding circuit-breaker.

The trip circuit logic is a trip scheme, identical to the one used by the BBP system, this is used by the CBF relay to selectively trip all of its back-up circuit-breakers.

The implementation of this protection function can range from being fully independent using stand-alone relays to a completely integrated CBF function within the BBP system.

8.2.1 Implementation of CBF protection

Independent CBF relay – an independent relay exists dedicated to perform this function. Typically it is located in each bay panel, close to the feeder protections.

This location reduces the ‘start’ hard wiring between the protections and the CBF relay. A hard wired circuit must exist between the relay and the tripping logic.

Integrated CBF function in main feeder protections – in each feeder protection, a CBF function is implemented. If there is a main 1 and a main 2 protection then a duplication of the CBF function might occur.

This solution does not need the ‘start’ hard wiring or a special relay unit for the CBF function which is an advantage. But, the disadvantage is the duplication of this protection function which is not common for security reasons. It also has the disadvantage of being difficult to separate this function from the feeder main protection function. This is especially important during maintenance and testing.

Integrated CBF function in centralized BBP – In this solution, the centralized BBP, the CBF function is integrated together with the BBP function. For this implementation it is necessary to connect all feeder main protection starters into the centralized BBP. This solution has the disadvantage that it increases the wiring for the starting purpose. The advantage is that the CBF function can utilize the tripping logic of the BBP.

Integrated CBF function in distributed BBP bay units – if there is a distributed BBP system, then a bay unit is installed in each bay panel. This bay unit can have an integrated CBF function.

The solution has the advantage that both the CBF relay and the trip logic is integrated in the same system, the BBP system, which replaces the hard wiring used for the tripping logic by an optical fibre link. It also has the advantage that there is no hard wiring to start the CBF function from a BBP trip. At the same time, the trip circuit between the trip logic and each bay panel is done by the same optical-fibre link.

As a consequence, both functions are integrated in the same relay, sharing the same current input, the same tripping logic, and tripping circuits which means that there is no independence between them.

8.2.2 Implementation of the trip circuit logic for CBF protection

Independent trip circuit logic – this is the traditional approach used to implement the tripping logic. In the substation there is a central panel where isolator status is monitored and, with the help of a special relay design a trip path is constructed.

When a CBF relay trips, it sends a trip command to the central panel which is re-sent to all back-up circuit-breakers.

This solution has the advantage that each CBF protection and BBP uses their own tripping circuit logic. This means that a problem in the CBF trip logic due to an outside factor does not jeopardize the BBP logic, and vice- versa. This aspect is of enormous importance to the dependability since the CBF function is a local back-up function of the BBP.

On the other hand, the security of the system is reduced since there are two trip logics and the risk of an unwanted trip due to a mal-operation is larger. It also has the disadvantage of expensive maintenance and high engineering costs.

Integrated in the BBP system – It is easy to see that the trip circuit logic used by the CBF function can be the same as the one used by the BBP. In this implementation, both protection systems share the same logic. The type of BBP system used is of no relevance, it can be used in a high impedance type or in a centralized or decentralized low impedance type.

This solution has the advantage of being inexpensive, since there is only one trip logic. This approach also reduces the probability of an unwanted trip due to mal-operation since there is only one tripping circuit.

As a disadvantage, the dependency between functions no longer exists; a problem in the trip circuit logic will compromise the use of the CBF function by the BBP and vice-versa.

8.3 External CBF starting

If the CBF protection is an integral part of a busbar protection it is of the utmost importance to provide all the necessary arrangements required to start each individual feeder CBF protections with trip signals from any feeder protection. This is necessary in order to ensure the fastest fault clearance time in the case of a feeder circuit breaker failing to clear the fault.

When the CBF protection is external then only back trip commands from all feeder bays can be connected to the busbar protection in order to properly route the tripping command to all associated circuit breakers.

9 Dead Zone / End Fault Protection and impact of CT location

The zone between the CT and the CB deserves special analysis and treatment. This zone is called an “end zone” when the CT and CB belong to a feeder bay and a “dead zone” when both elements are part of a bus coupler or bus section bay.

The location of the CTs define what can be called the “measuring boundary” and the location of the CBs create what can be called a “clearing boundary”

9.1 End fault protection

Figure 9-1 shows the measuring and clearing boundaries for a single busbar station. For faults within the end zone the BBP will either over-trip or under-trip. But the fault itself will only be cleared by operation of a back-up protection. The objective should be to accelerate or to be more selective when tripping for faults between the circuit breaker and the CT when the CB is open. For this purpose it is common to use a function called end zone or end fault protection (EFP).

Normally the CB position is not used by the BBP. The position of the CB however is necessary to establish an end zone protection. The EFP, typically a fast acting overcurrent stage, is only active when the CB is open and is deactivated by the circuit breaker close command or CB closed position.

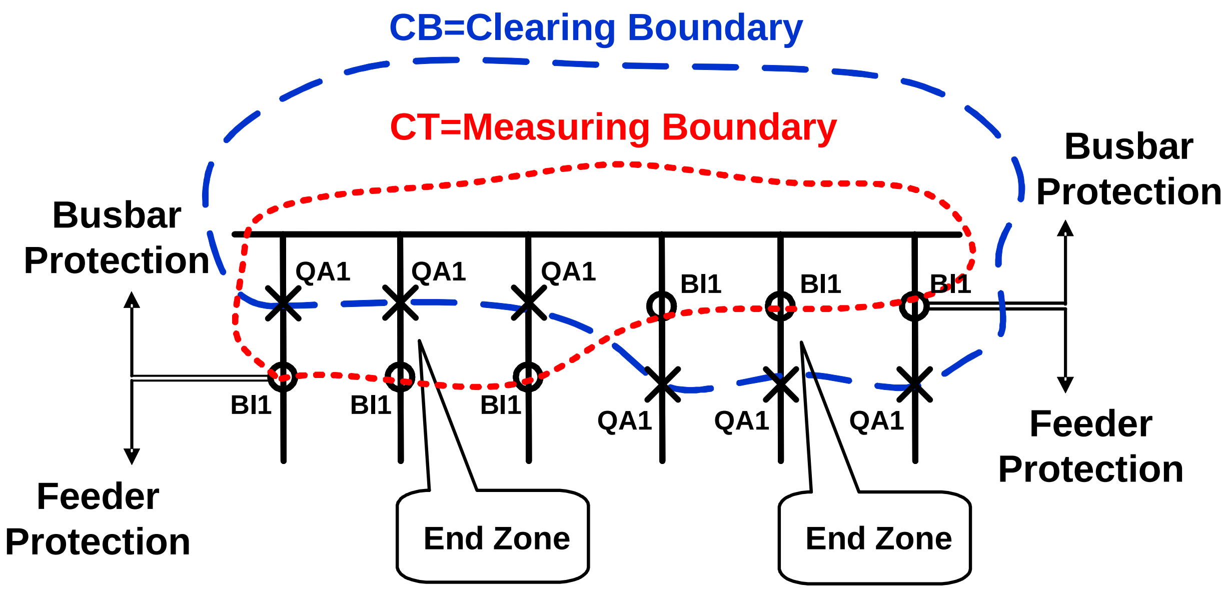


Figure 9-1 End fault protection

9.2 Methods to clear faults in the end zone of a feeder

9.2.1 CTs installed on both sides of the CB

When the CB is closed, the BBP will trip for the internal fault shown in Figure 9-2 but the fault will not be cleared. Final fault clearance will be made by tripping the remote end CB by some other means.

When the CB is open the EFP will prevent operation of the BBP by removing the feeder current from the bus zone measurement. The EFP can further provide an intertrip signal to clear the fault without delay by tripping the remote end CB if communication facilities are available.

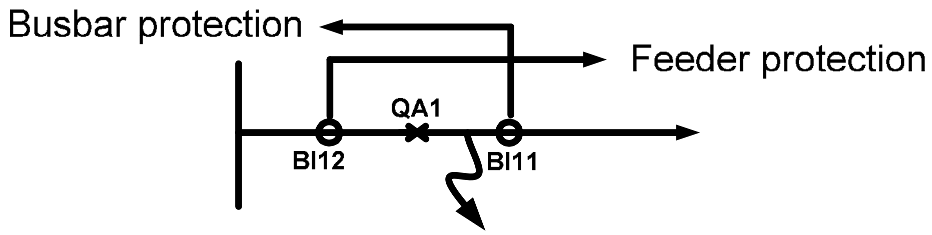


Figure 9-2 CT on both sides of CB

9.2.2 CT located on the busbar side

When the CB is closed, the BBP will not trip for the external fault shown in Figure 9-3. The feeder protection will trip but the fault will not be cleared from the busbar side. Final fault clearance will be made by tripping the bus by other means; e.g. CBF.

When the CB is open the EFP will enable the operation of the BBP (increase dependability) by for example removing the feeder current from the bus zone measurement. The BBP will clear the fault instantaneously by tripping the affected bus zone avoiding delayed fault clearance by CBF.

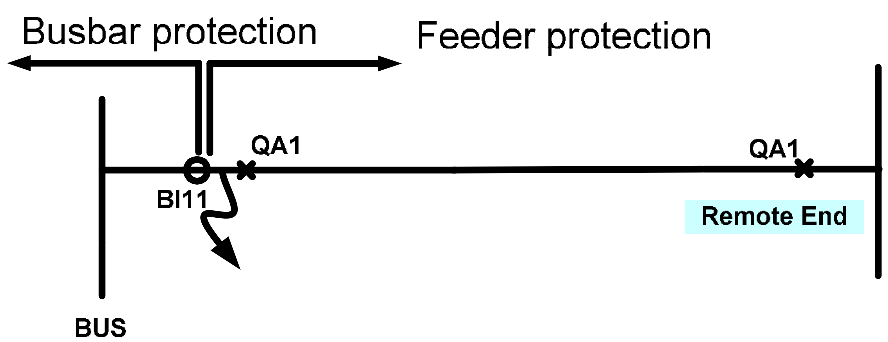


Figure 9-3 CT on busbar side

The following example emphasises the importance of the EFP. In the event of an end-zone fault as shown in Figure 9-4 and a weak-infeed source (e.g. a small generator feeding a fault through the high impedance of a transformer), the EFP will instantaneously clear the fault when the CB in the faulty feeder was open before the fault. With the CB closed prior to the occurrence of the fault, the fault will be cleared by operation of the CBF. Without these protections such faults will only be cleared with a long time delay by a protection installed on the weak-infeed source.

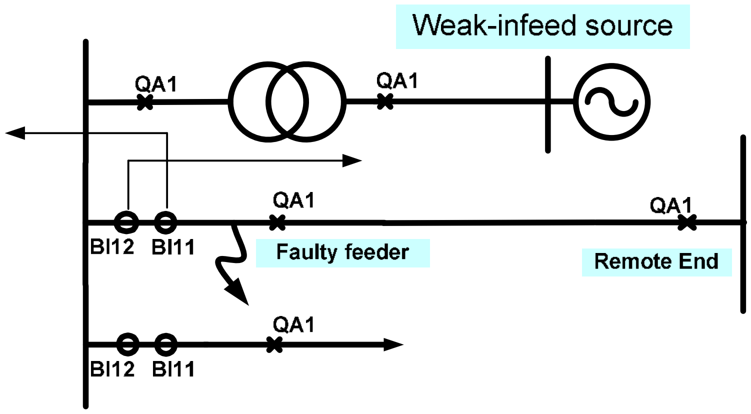


Figure 9-4 Example when end fault protection is crucial

9.2.3 CT located on the line side

When the CB is closed, the BBP will trip for the internal fault shown in Figure 9-5 but the fault will not be cleared. Final fault clearance will be made by tripping the remote end CB by some other means.

When the CB is open the EFP will prevent operation of the BBP (increase security) by removing the feeder current from the bus zone measurement. The EFP can further provide an intertrip signal to clear the fault without delay by tripping the remote end CB.

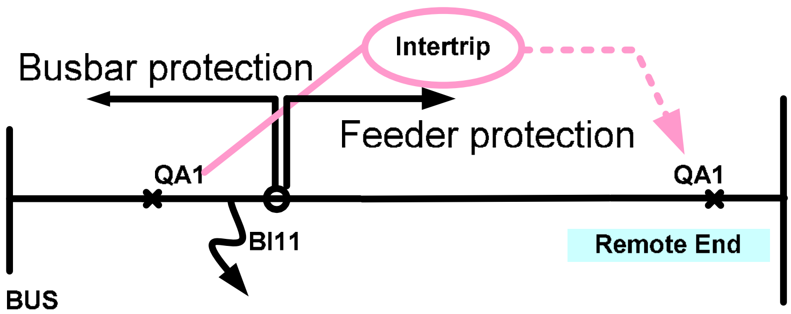


Figure 9-5 CT located on the line side

9.3 CT location for substations with transfer busbar

In substations with a transfer busbar, analysis of bay CT location is undertaken in consideration of its position with reference to the position of the transfer bus isolator QB7.

Three different possible CT locations (1),(2) and (3) (see Figure 9-6) have to be considered depending on the position of the transfer bus isolator:

(1) CT internal (related to QB7), bus side (related to QA1)

(2) CT internal (related to QB7), line side (related to QA1)

(3) CT external (related to QB7)

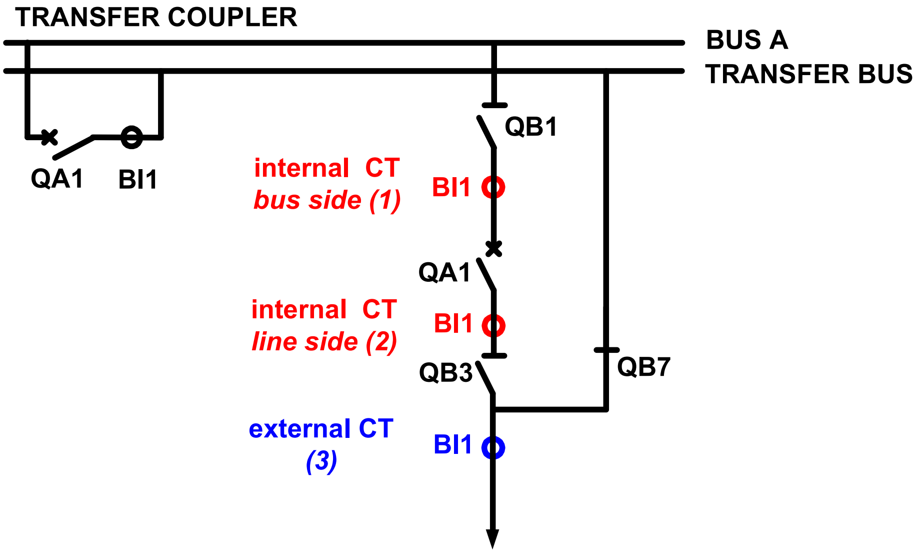


Figure 9-6 CT location for substations with transfer busbar

When the transfer bus isolator QB7 is open the behaviour is the same as with no transfer bus. The behaviour of the EFP as previously described applies for location (1) “bus side CT” and location (2) or (3) “line side CT”.

When QB7 is closed EFP behaviour is different for location (1) or (2) “internal CT” and location (3) “external CT”.

9.3.1 External CT

When the CT is located in position (3) the state of by-pass isolator QB7 (open or close) must be considered to properly protect the busbar during faults between CT and CB. If isolator QB7 is closed the load current through the CT is also measured by BBP while the feeder CB is open. The current thus does not indicate an end zone fault. Therefore, with the isolator closed the EFP function should be blocked.

9.3.2 Internal CT

For the case when the CT is located in position (1) or (2) the transfer busbar cannot be protected by the BBP since the transfer coupler CT becomes the zone measuring boundary when a feeder is in transfer mode. At that time the feeder protection shall be connected to the transfer coupler CT. The transfer bus is then protected by the feeder protection as part of the line. End zone faults for case (2) will be cleared by feeder protection, but EFP can be used to prevent BBP operation (increase security). For case (1) the EFP provides fast tripping in case of an end zone fault (increase dependability).

A check zone cannot be established without special measures during transfer mode. Only if the principle of the check zone (being independent of any isolator information) is violated and the transfer isolator status is taken into account, a check zone can be put into effect. The check zone will be terminated by the CT of the transfer coupler.

9.4 Dead zone protection

Figure 9-7 Measuring boundary and Figure 9-8 clearing boundary show the measuring and clearing boundaries for a coupler bay, (bus coupler or bus section) with one CT. Usually CB position is not used for BBP therefore for faults within the dead zone even with the bus coupler CB open the BBP for bus B will trip whereas for BBP zone A it will be seen as an external fault. Final fault clearance will be made only by tripping bus A. If no other measures are taken the fault will be cleared with time delay by operation of a back-up protection. To accelerate clearance of such faults and to maintain selectivity when the bus coupler CB is open, dead zone protection (DZP) can be provided within BBP. The position of the CB is necessary to establish a DZP. The DZP is only active while the bus coupler CB is open.

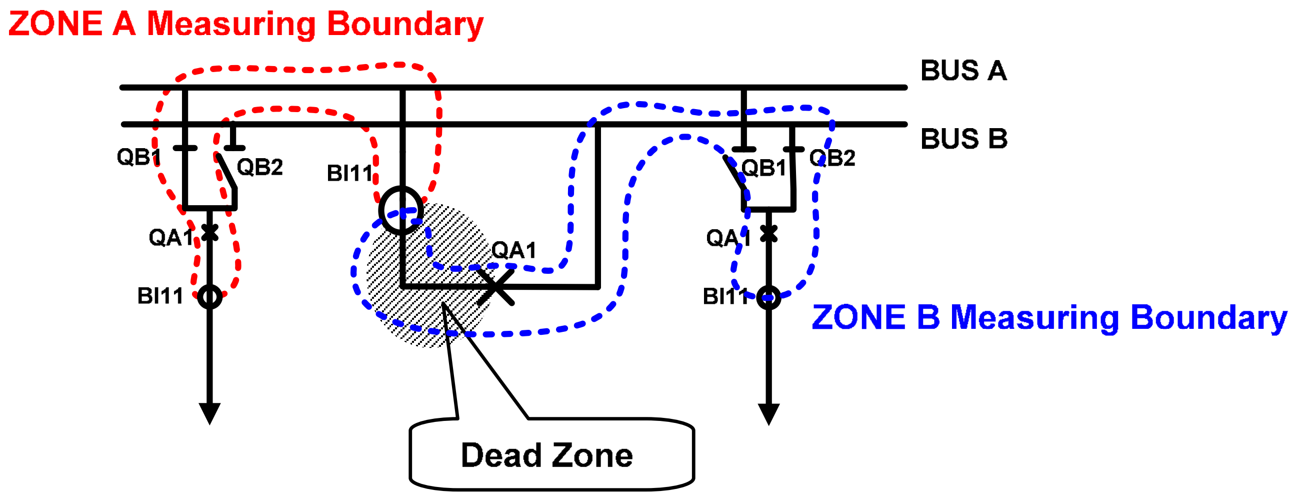


Figure 9-7 Measuring boundary

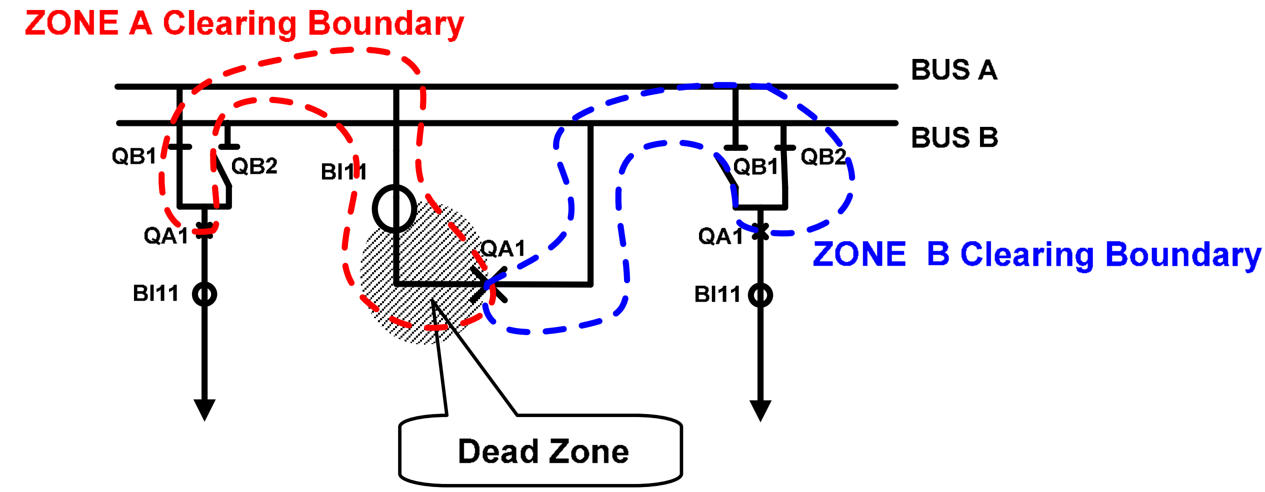


Figure 9-8 clearing boundary

9.5 Methods to clear faults in the dead zone of a coupler

9.5.1 Bus coupler with one CT

When the bus coupler CB is open, the DZP removes the current measurement of the bus coupler bay from both differential zones. This in effect moves the measuring boundary, shown in Figure 9-9 from the bus coupler CT to the bus coupler CB. This ensures selective and instantaneous fault clearance.

When the bus coupler CB is closed (Figure 9-9), selective tripping can not be achieved (bus B is tripped) but DZP will ensure delayed operation of BBP for bus A and subsequent fault clearance.

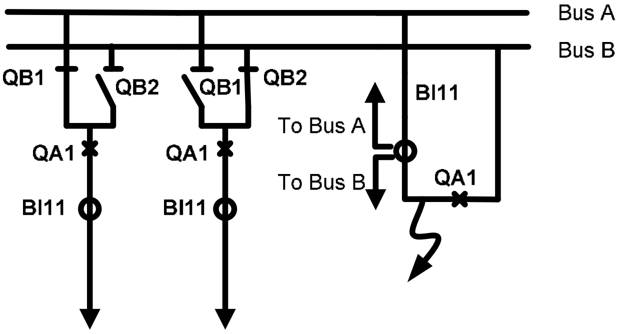


Figure 9-9 Bus coupler with one CT

9.5.2 Bus coupler with two CTs

In this configuration the bus coupler has two CTs, one on each side of the CB, connected in such way that the two measuring zones overlap (see Figure 9-10).

A dead zone does not actually exist for this configuration. Due to CT arrangement, both zones will be tripped and the fault is cleared instantaneously but not selectively.

The advantage of using DZP in this case is that it will ensure selective tripping when the bus coupler CB is open. This is achieved by removing the current measurements for the bus coupler bay from both differential zones, as described in Section 9.5.1

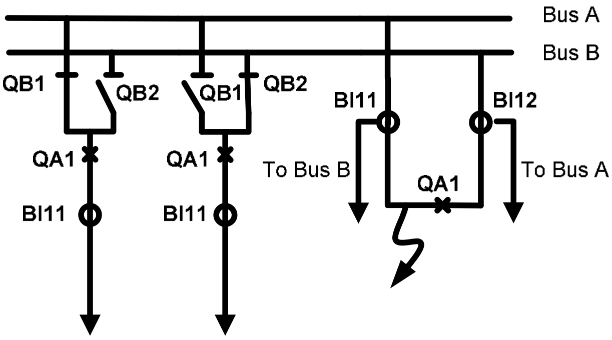


Figure 9-10 Bus coupler with two CT

9.6 Circuit breaker close command

When the circuit breaker position is monitored for BBP (e.g. DZP or EFP) it is essential to read in the closing command to the circuit breaker to ensure that current measurement is reassigned to its busbar protection zone(s) in time (see Section 7.3.2)

10 Output Signals

10.1 Busbar protection tripping

In the event of an internal fault all circuit breakers associated with the faulted zone will be tripped and the associated circuit breaker failure function initiated in the bays affected.

All busbar protection tripping commands should have sufficient duration in order to ensure the correct tripping of all affected circuit breakers. The tripping circuits shall be designed in accordance with local practices, regulations and specifications.

10.2 Intertripping

Intertripping is defined [2] as the tripping of CBs by signals initiated from protection at a remote location, independent of the state of the local protection, unlike permissive or blocking schemes that also considers the state of local protection. The intertripping concept provides the opportunity for fast and unconditional tripping of remote breakers that:

otherwise would rely on local conditions, which in some cases would prolong the tripping time, or with weak systems even cause misoperation

by prior analysis of the event are foreseen to be tripped, and thus can be tripped instantaneously

Single communication channel systems independent of the transmission medium can be vulnerable to tripping failure or delayed tripping unless the communications channel is made redundant. Depending on the policy of the utility, these systems should be designed to take into account reliability of the communication links between the substations. This would suggest that a second communications link be established between the two ends, preferably using a different communications method, a different signal path, or both.

Intertrip pilot protection is in this context designed to provide high-speed tripping for busbar faults, and also to provide the benefits of backup protection for adjacent sections. The design of intertrip schemes can be direct or redundant. Direct intertrip schemes send a signal directly without any delay to the trip coil at the remote end breaker, where the trip is initiated. Redundant systems offer a form of security protection by requiring that two intertrip signals be received, thereby providing assurance that a true signal was sent and not just a noise or false signal. Sometimes, an intertrip can also be initiated on detection of a circuit breaker failure condition at either end of a line.

This is a summary of circumstances in which an intertrip maybe required in BBP applications:

When a CB failure occurs in one bay following a busbar fault, an intertrip to the remote end(s) of the line should be sent immediately.

For the case of a fault that occurs between a circuit breaker and the CT on the line side, an intertrip is sent to the remote end(s) of the feeder. Depending on the station arrangement, this intertripping signal is either initiated by the BBP or the BFP. If the circuit breaker is initially open, an unselective tripping of the busbar can be avoided by the use of end-fault protection. This fault could be cleared instantaneously through remote line protection and echo signalling. In a single breaker / CT configurations, (see Figure 4-1, Figure 4-2, Figure 4-3 and Figure 4-5) the

BBP can send an intertripping signal to the remote end breaker independent of the fault location to speed up the fault clearing time without comprising security. In a double breaker / CT configuration (see Figure 4-4, Figure 4-6 and Figure 4-7) an intertripping signal is only initiated by the BFP due to security. A fault between the CT and breaker is in such a case considered as a “breaker failure” condition. This instance has already been described earlier and is known as Dead Zone or End Fault protection.

For the case of a fault that occurs between a circuit breaker and a CT on the busbar side, possible intertripping signals is related to the line protection function.

In a station with a transfer bus (see Section 9.3.1) and during active transfer, for a fault on the transfer bus an intertrip command shall be send by the BBP to the remote end, if the fast fault clearance is required. Modern BBP can also receive the intertrip command for individual bays. They also offer automatic re-direction of the trip command to the transfer breaker if particular bay is on transfer.

Trip command to other busbar zones such as during bus coupler failures is interpreted as a back-tripping function, not intertripping.

10.3 Signalling

Busbar Protections can also provide status of isolators and circuit breakers, starting and trip signals, blocking signals, circuit breaker failure signals, supervisory check zone activation and so on.

All of this information may be accessible through auxiliary output contacts, programmable LED’s, HMI or communication protocols. These signals can be configured as “self-reset” or “latched”. ”Self-reset” means that the contact will track the present state of the assigned signal; ”latched” means that the contact remains in its status until a reset is given by a button, a communications command or other pre-programmed signal.

Depending on the type of BBP (distributed or centralized) these output contacts will be distributed between bay units and a central unit or all can be integrated in the centralized device.

10.4 Alarming

A modern numerical BBP should provide alarm conditions when any of the BBP functions is not performing correctly. This may be due to internal errors (e.g. component failures, software malfunction), external conditions (e.g. loss of auxiliary voltage supply) or manual blocking.

Types of failures that might generate an alarm are similar whether the busbar protection system is centralized or distributed, but some specific failure types exist only in a distributed type of BBP. In any event, when a failure is detected the protection system may be blocked to avoid over-function.

The most common failures are: problems in the auxiliary voltage supply (external or internal), faulty analogue processing hardware (A/D converters), faulty memories, software module failure detected by a software watchdog. All of these possible errors are applicable to both centralised BBPs and distributed BBPs, taking into consideration that in distributed BBP such errors can occur both in bay units and the central unit.

Communication problems are specific to distributed BBP's and must be considered because they can seriously affect reliability and the availability of the protection. A broken fibre-optic link between a bay unit and the central unit, defective Tx or Rx hardware in any of the equipment, both will finally produce communication errors that have to be considered.

Alarm conditions generated after any of these problems should be accessible to the user in order to take appropriate measures. This can be accomplished remotely (through an auxiliary output contact or communication protocol) and/or locally (with LEDs and/or indication at the HMI).

Some differences between a centralized BBP and a distributed BBP, apart from the possible specific problems that might occur in a distributed system, are:

In a centralized BBP the alarm signals are unique, whilst in a distributed BBP each bay unit can provide its own alarm indication (output contact, LED indication etc).

In a centralized BBP if an error is detected that may result in the whole system being out of service, while in a distributed BBP if an error is detected in a bay unit or in the communication link between the central unit and a bay unit, the availability of the rest of the system might be maintained although its functionality will probably be reduced. If the error is detected in the central unit, the possibility of losing the whole system increases significantly.

Characteristics of the alarm output contacts are the same as the signalling output contacts. The only requirement is at least, one N/C contact should be available.

11 Actions after busbar protection operation

The WG has conducted a survey which examines the actions taken following operation of the busbar protection. Firstly, it seems to be generally agreed that busbar faults are quite rare compared to faults on other network components such as transmission lines etc. However, the quality of answers seems to vary amongst utilities.

When busbar faults occur most utilities will analyze these faults very thoroughly due to the inherent consequences. Most power systems are not dimensioned to handle busbar faults without significant loss of load and production and reduced transfer capacity through the grid. N-1 is the state of the art planning and operation criterion throughout the world, although a probabilistic approach has made a step forward in the last decade. With a busbar fault the consequences to the power system are unknown prior to the actual event occurring as these faults are not likely to be part of the operational criteria. Thus, a busbar fault may result in shutdown of several generators, transformers and transmission lines. There may be islanding, frequency and transfer capacity problems due to the sudden changes of power flow, which is less likely to happen with a single transmission line fault. Normally a busbar fault will stress the operators due to the complexity and consequences. The first action will be to reallocate loads and production, restore the nominal frequency and bring the system into N-1 mode. Parallel to this the utility will begin to analyze what caused tripping of the BBP.

Genuine busbar faults can be localized by visual inspection. The utilities report that phase-ground busbar faults are the most common in the case of a true busbar fault. In most cases the fault is caused by problems with disconnectors, support insulators, primary conductor drop, circuit breakers, failure to remove earthing etc. Lots of utilities report the need for:

- visual busbar inspection
- analysis of disturbance records to conclude whether there was a true busbar fault or mal-operation of the BBP

Only one utility stated that remote restoration may start without any inspection if there is strong evidence that the BBP has mal-operated, e.g. for a transmission line fault. No utilities have reported the use of auto-reclosing in case of such a fault, which is most likely due to the risk of a permanent fault occurring. However, it is known, that in some countries special auto-reclosing procedure is used after BBP operation. Normally manual energization and restoration commences after the analysis is performed and the fault location and reason is known.

There is great diversity in how utilities handle trip signals. The survey indicates a mixture of both self-reset trip signals and latched tripping signals, and direct tripping versus tripping through auxiliary relays. It is not possible based on the survey to conclude about a general practice in one direction or the other. However, some utilities prefer direct tripping specifically for security reasons. As numerical BBP systems become more common when refurbishing existing stations, the use of distributed systems and direct tripping will increase.

12 Modern relay features

12.1 Bay Out of Service Features

During the routine inspection of a bay, the protection and control devices and the local protection functions in the bay unit are also generally checked. To avoid the risk of unintentional tripping of the BBP relay, the isolators in the bay under test should be open during the BBP bay unit inspection. In this way, tests such as applying current injection for the bay unit will not affect the differential current measurement of the remaining BBP system.

However, during the routine inspection of a bay isolators may provide incorrect status (if engineers are working on them, for example). To prevent the busbar protection from operating with an incorrect busbar image in such situations, provision is made for applying an inspection signal to a bay unit. This enables one or several isolators or bus-tie breakers to be set to “OPEN”. When all the isolators belonging to a bay are set to “OPEN”, the bay current is not assigned to a protection zone and the current of the corresponding feeder is not included when the busbar protection algorithm is executed.

Generally, to prevent unintentional operation of the BBP relay while testing, it is recommended to either keep the isolator positions open or isolate the complete bus Zone. Alternatively BBP relay manufacturer recommendations shall be followed.

12.2 Monitoring Functions

To ensure high reliability of the relay performance and to reduce demand for BBP scheme maintenance, modern BBP relays incorporate comprehensive self-monitoring functions for both the hardware and software (internal supervision) and for the BBP scheme (external supervision). This may include isolator, CT, and circuit breaker circuit supervision and other functions that may be manufacturer specific as they are related to the hardware and/or software (implemented algorithms). External and internal monitoring functions may include the following:

12.2.1 External monitoring/supervision

12.2.1.1 Isolator monitoring

Monitoring functions for isolators include operating time, status, and auxiliary voltage. Isolator malfunction causes an alarm and, if desired, three-phase blocking only of the affected protection Zone to avoid blocking non-affected Zones.

If an isolator changes position, for instance from the OPEN to CLOSED position, it requires a certain time (isolator operating time) to reach the other position. If after a preset isolator operating time no clear indication of the new position is received, an isolator malfunction is declared.

There are several commonly used methods to detect the loss of the auxiliary power used for the disconnector replica logic.

Usually, the isolator auxiliary voltage is sub-fused in each bay. If the voltage is missing, all of the isolators in this bay will display the bit pattern 0/0 (neither OPEN nor CLOSED). This faulty condition can be detected by cross-checking with the other isolator positions. The bay with the unknown isolator position is either assigned the old position according to the busbar protection or all isolators serving this bay can be considered as CLOSED.

A different way to detect the loss of the auxiliary voltage in a decentralized BBP scheme is to use a separate binary input in each bay unit for voltage supervision. As a result of the supervision pick-up, the last position will be saved.

The condition is indicated by an alarm (to prevent the switching of isolators in this state).

In the event of short-circuits in feeders, the busbar protection remains stable — even with a wire break in the check-back signal lines for isolator status. In that case, when Scheme 1 is selected (see Section 7.2), this can lead to unselective tripping (reduced selectivity) if all of the following conditions are fulfilled simultaneously:

- Isolator is in the OPEN position
- Information loss (i.e. 00 or 11 condition) from this disconnector is received
- Second isolator for the feeder is in the CLOSED position
- BBP will automatically recognise this as an on-load transfer situation and switch these two differential measurement into one common zone
- Internal fault happens on one of the two busbars

Non-selective tripping might be prevented by additional measures such as interlocking of the TRIP command with the integrated overcurrent relay or monitoring the pick-up of the feeder protection.

When Scheme 2 is selected (see Section 7.2), this can lead to no-tripping (reduced dependability) for an actual busbar fault if all of the following conditions are fulfilled:

- Load transfer has started by giving a close command to the second busbar disconnector in a feeder bay
- Information loss (i.e. 00 condition) from this disconnector at that point of time will cause the BBP to maintain the two separate zones while on the primary side only one zone effectively exists
- If the pickup of the differential protection is not set sufficiently high (above maximum load current) mal-operation of the BBP is even possible (loss of security)
- After a preset time both BBP zones shall be blocked due to disconnector alarm in order to prevent mal-operation for possible external faults
- Then internal fault happens on one of the two interconnected busbars
- BBP will not operate because it is blocked (loss of dependability)

Wire breaks are alarmed as an isolator malfunction status individually for each feeder.

A parameter can be used to specify which isolator status will be assumed if the status of a switching device is not plausible (OPEN and CLOSED at the same time i.e. ‘don’t believe it’).

The interpretation for each isolator status indication is shown in the following table:

Table 12-1 Isolator status indications

Isolator status indication		Meaning	Reaction
CLOSED	**OPEN**		
1	0	Isolator CLOSED	No alarm (normal operation)
0	1	Isolator OPEN	No alarm (normal operation)
1	1	Isolator status not plausible	Time Delayed Alarm
0	0	Isolator malfunction: - operating time - wire break - no aux. voltage	Time Delayed Alarm

Isolator malfunctions (plausibility or runtime errors) and failures of the auxiliary voltage supply for isolator are not alarmed until the set isolator operating time has elapsed.

12.2.1.2 Errors caused by linearized current transformers

Linearized current transformers (class TPZ, according to IEC) have phase angle errors, the secondary current lags behind the primary current. In the event of a fault, the circuit breaker will interrupt the primary current near a current zero. However, the secondary current will continue to flow, exponentially decaying to zero. The phase angle error and the time constant depend mainly on the burden. The phase angle error increases and the time constant decreases with increasing burden. BBP relays must be designed to differentiate this false differential current from an actual fault.

12.2.2 Internal monitoring/supervision

The entire protection system is cyclically monitored from the measuring inputs up to the trip relay coils. In case of a distributed arrangement, the data communication between central and bay units is included in the supervision as well. Time monitoring functions (watchdogs) continuously check the program sequences of each processor module. Failure of a processor or malfunctions in the program sequence will initiate an automatic reset of the processor system. Additional plausibility checks and program runtime checks ensure that program processing errors are reliably detected. Such errors also lead to a processor reset and a system restart.

12.2.2.1 Auxiliary and reference voltage monitoring

All supply voltages and relevant reference voltages inside the relay are monitored. If the voltages are outside the predetermined range, BBP operation will be blocked, which may be selective or complete - depending on the reported voltage deviation and the affected device is automatically removed from service. Voltage dips of less than 50 ms duration will not affect the BBP system.

12.2.2.2 Memory supervision

The memory modules of the central unit and the bay units are periodically tested for faults.

- A checksum is formed for the program memory (Flash EPROM) during start-up and cyclically during operation.

- For the RAM, a data pattern is written during start-up and read again. Write and read results are compared.
- For the parameter and configuration data memory (EEPROM, nvRAM), the checksum of the stored quantities is formed and compared with the checksum calculated during each new writing process.
- For the dual-port RAM of the slave modules, the stored parameters and configuration data are compared with the data in the master module.

12.2.2.3 Measured value monitoring

The secondary circuits of the bay units are cyclically monitored from the instrument transformers up to the bay unit on a per feeder basis. One solution is to execute the following plausibility check:

$I_{err} = |I_{L1} + I_{L2} + I_{L3} + I_E|$, I_{err} is the error current

$I_s = |I_{L1}| + |I_{L2}| + |I_{L3}| + |I_E|$, I_s is stabilizing current

I_{L1}, I_{L2}, I_{L3} are the currents of the three phases and I_E is the earth current.

The measured value monitoring algorithm engages if I_{err} satisfies the following two conditions:

1. $I_{err} > k_{\min} I_{ph}$, k_{min} is a factor determining I_{err} minimum value (threshold) (such as k_{min} =0.5), I_{ph} is the phase current.

2. $I_{err} > k_s I_s$, k_s is stabilizing factor (such as k_s =0.125).

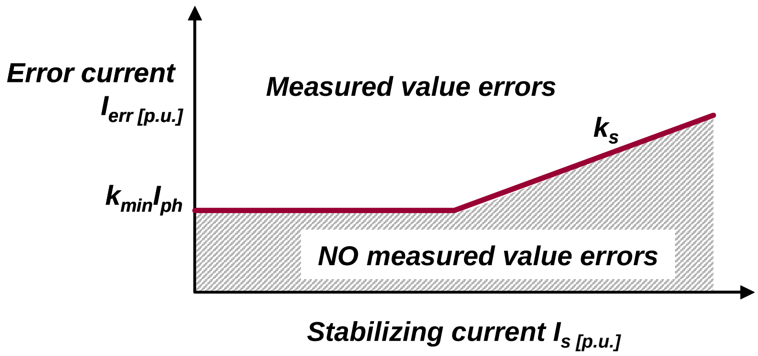


Figure 12-1: Characteristic for measured value monitoring

If the supervision algorithm detects that the measured values are not plausible, the protection is blocked for this cycle. If this error status prevails for a longer time, the BBP system is selectively or completely blocked followed by an annunciation of this status, such as alarm.

12.2.2.4 Battery monitoring

In case of an auxiliary power supply failure, relevant BBP information which has been achieved using internal batteries must be available. This information includes LED states, date and time, operational and fault event records. If the battery voltage drops below threshold, a low battery status is declared.

12.2.2.5 Bay unit or communication failure monitoring

With distributed BBP arrangements, the serial links between the bay unit and the central unit are continuously monitored. A failure in a bay or in the communication link between the bay unit and central unit initiates alarm. In both cases, the BBP in the affected Zone will be blocked.

12.2.3 Internal and external trip circuit monitoring

The relay unit trip circuits are controlled via several independent channels. The circuit breaker trip circuit can be monitored by integrated or separate test facilities. These are usually based on measurement of the voltage drop across the circuit breaker trip coil by injection of a small current (a few milliamperes).

12.3 Detection of problems in CT secondary circuits

The busbar differential relay is quite unique because usually CTs from every bay, often with very different ratios and classes, are connected to the same protection relay. When static BBPs are used, the CT secondary circuits are switched by disconnector auxiliary contacts or by interposing bi-stable relays. Thus there is the possibility that some of the CT secondary circuits can be open circuited or short circuited by mistake. This can cause unwanted operation of the busbar differential protection scheme.

With modern, numerical BBP relays the required CT switching is not performed in the CT secondary circuits. Instead this is done in the relay software. Thus, the opening or shorting in the CT secondary circuits due to equipment failure is avoided. However, there is still the possibility that the CT secondary circuits are open or short circuited by mistake. Modern numerical relays typically have built-in supervision methods to detect such conditions. Some typical methods are listed below:

- differential current magnitude increase above the preset alarm level but below the trip level
- incoming and outgoing currents both change for an internal or an external fault. In case of any problem in one of the CT circuits only one of them will change indicating that the disturbance is not a real primary fault. This can be done on a per bay basis instead of monitoring total incoming and total outgoing currents.

By using these methods unwanted operations due to a problem in the CT secondary circuits can be avoided. By blocking of the affected discriminating Zone(s), BBP stability can be preserved even in case of a consequent external fault.

12.4 Service values

Modern numerical busbar relays have human-machine interface (HMI) to provide information about the present status of the BBP and substation. A busbar relay may be used as a small monitoring system.

The single-line diagram can graphically visualize the status of isolators and circuit breakers. In addition, voltage and current values can be displayed. Event lists and disturbance records are additional features that provide data about the system events.

12.5 Numerical BBP testing and commissioning facilities

The BBP setting can be conveniently accomplished by a PC. For commissioning and factory acceptance test purposes, modern BBP relays can also effectively be virtually tested by a PC. For instance, the relay can be interfaced to a PC that runs software that simulates binary input status. This eliminates the need for other test equipment.

Input/output signal/commands can be forced to a certain status simulating different operating conditions. The software matrix allows the user to easily arrange input/output signals/commands. In addition, I/O signals and commands can be added at any time and more than one signal or command can be assigned to one input/output. This eliminates the need for any external wiring.

Numerical BBP can also offer advanced features which can facilitate the commissioning of live substations, periodic testing of BBP and maintenance of the individual bays. Some of these features are:

Bay out of service (See Section 12.1)

Blocking trip signal output(s) from one/all differential zone(s)

Blocking of the trip outputs to the individual bay circuit breakers

Forcing status (e.g. Open/Closed) of the primary switchgear apparatus

12.6 Remote access

Modern substations have been designed to have remote access to protection, metering, and control information including the BBP that can provide a wide variety of data.

BBP should have a sufficient number of communication ports to allow local access, communication to the Substation Control System, and remote connection to the engineering office, operator desk, and SCADA. It should support access with different types of modem, by serial or Ethernet TCP/IP port.

Remote connection to BBP enables on-line monitoring of the relay performance, viewing measurements such as differential and restraint currents, phase currents from each measurement location, sequence currents, voltages, and frequency. It is also possible to download/upload relay scheme/settings, upload event list and disturbance records, and configure the relay logic.

12.7 Disturbance recording & Event list

The BBP disturbance recorder can record currents and numerical signals of circuit breaker and isolator status from all bays in the substation and optionally, bus voltages. This provides a complete image of the operating conditions in the substation, which enables performance diagnostics of apparatus such as circuit breakers, isolators, transformers, reactors, CTs during normal conditions (testing, maintenance) or faults. Disturbance records should be in COMTRADE format.

The event list typically includes a list of disturbance events with time tag.

12.8 Integration of other functions in BBP

In bay units of a modern de-centralized BBP arrangement additional protection/control functions can be integrated and used as main or back-up protection. These functions may include line distance protection, transformer differential protection, CBF protection, auto-reclosing, and synchrocheck. In addition, features such as CBF, end fault, and end blind spot protection functions can also be included. Benefits include significant cost reduction in hardware, as well as time saved during engineering, commissioning, and maintenance.

13 Busbar Protection Setting considerations

13.1 Criteria of protection setting

This section deals with the setting of numerical biased differential types of busbar protection.

The main criteria when setting bus bar protection irrespective of its type or application is to achieve maximum sensitivity for internal faults, while preserving high security (stability) for external faults.

13.2 Setting of Busbar Protection

Protecting busbars starts with calculation of the magnitudes of incoming/outgoing short circuit currents for the separate feeders for internal/external faults. This short circuit current may arise from different load flow situations and switching conditions depending on the power system topology. That is, the load flow situation providing a minimum short circuit current for one feeder, may provide higher short circuit currents for the other feeders. Some of these currents are used to set the busbar protection, and some are used to set the CBF protection. This example discusses how to set the parameters and which calculations to perform:

Example 1: Short circuit calculations

Given a busbar with two lines in a single busbar arrangement as shown in Figure 13-1, suppose the following nominal data for the CT and transmission line:

The nominal current for the CT, In = 500 A.

Maximum load current on each of the two lines is $I_{max,load}$ = 400 A.

Minimum load current on each of the two lines is $I_{min,load}$ = 140 A.

Short circuit calculations are performed for different busbar faults (e.g. 3 phase, Ph-e, Ph-Ph), and this gives the following incoming currents when the fault is on the busbar (max/min values)

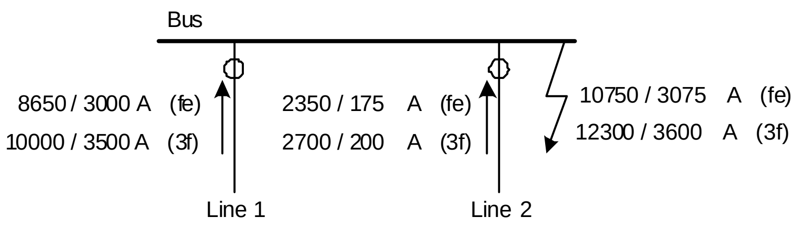


Figure 13-1 Maximum and minimum incoming feeder currents for internal faults. Phase-to-earth faults (f-e), three-phase faults (3f).

Notice that e.g. the maximum current for a busbar fault (12,3 kA) in this case is not the sum of each feeder current (10,0 + 2,7 kA), as these currents arise from different switching conditions in the grid.

For the same system, consider in Figure 13-2 the following max/min short circuit currents for external faults (i.e. the fault is somewhere on the respective lines). That is, the currents for

Feeder 1 refer to a fault at Feeder 1, and the fault currents for Feeder 2 refer to a fault at Feeder 2. The fault locations are close to the remote substations to give this minimum current typically required to set the current threshold for the CBF protection.

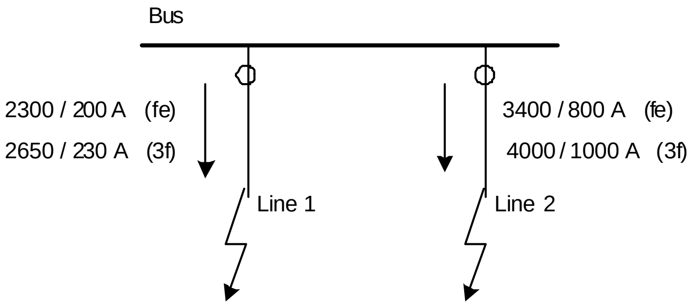


Figure 13-2 Maximum and minimum outgoing feeder currents for external faults. Phase-to-earth faults (fe), three-phase faults (3f).

13.2.1 Checking for CT saturation

Criteria for CT selection and an example are shown in Chapter 6.2. When selecting the CT or checking its performance, it should be considered maximum through-fault short circuit currents (symmetric and asymmetric) through the CTs. In Example 1 the maximum short circuit current through CT1 and CT2 is 10000 A.

13.2.2 Setting the threshold for pickup and tripping

The threshold for pickup and tripping should be set below the minimum expected fault current value with a safety margin, and if possible above the maximum load defined either by the CT with maximum primary rating or alternatively maximum expected load current in any of the bays. In some cases, there is a conflict in setting the BBP relay in this way, which may e.g. lead to tripping on high load currents – if the utility decides to trip on even the smallest fault current – which may be in a rare load flow situation. While considering measuring inaccuracy, CT nominal data, burden, and the fault type generating the smallest fault current, extreme, but realistic, variations in short circuit capacity should be considered as the basis for calculating these currents.

Consider example 1, and notice that the maximum load is 400 A. The loss of the CT connected to this feeder could cause an Idiff = 400 A. The minimum expected fault current for an internal busbar fault is 3075 A. The threshold for pickup must be set between load current 400 A and internal minimum busbar short circuit current 3075 A. Therefore, this value could be set as 0,7x3075 = 2150 A to allow a 30% margin below the minimum expected fault current (margin dependent on the utility practice). Security is satisfied since this value is well above the maximum load current.

13.2.3 Setting the stabilizing factor of the tripping characteristic

The gradient of the slope of the stabilizing factor should be set to avoid spurious tripping on external faults. A close-up external fault would cause the CT in the faulted feeder bay to carry all the fault current, while the infeeding bays only carry a fraction of this current. A high stabilization setting provides for more stability against faults outside the protected zone, but reduces the sensitivity for detecting internal busbar faults. Thus, the gradient should be set as low as possible and as high as necessary. The k-factor is manufacturer-dependent because they have different algorithms and ways of defining this factor. Thus, refer to the manufacturer's manual for setting recommendations. The criterion for an internal busbar fault could be written as Id > k x Is, where Id is the differential current, Is the stabilizing current and ‘k’ is the manufacturer-dependent factor.

Consider the tripping characteristic as given in Figure 13-3:

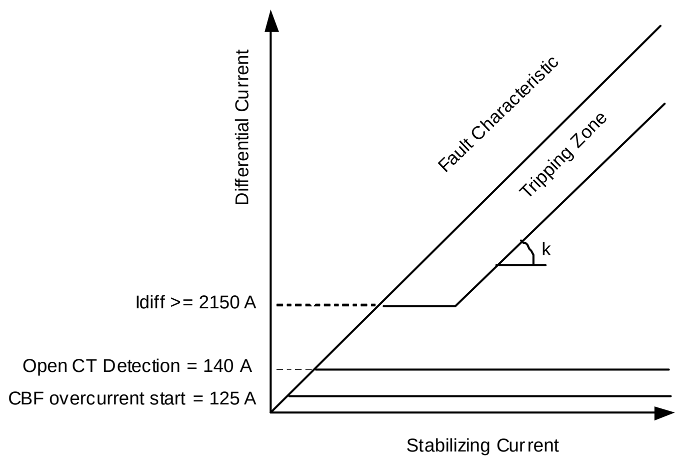


Figure 13-3 Differential biased tripping characteristic.

Two important factors that are related to choosing the right k-factor are

the type of current transformer: linear or iron-cored

the CT burden

The linear CTs reduce the DC component while the iron-cored CTs transmit the DC component without any noticeable reduction. The CTs with the highest burden (that are more likely to saturate) should be the basis for selecting the k-factor.

13.2.4 Setting overcurrent check condition in CBF

Circuit breaker failure protection is not only related to busbar protection, but is also started by other protection functions as e.g. the line and transformer protection. Correct breaker failure operation is thus dependent on the availability to measure even the minimum internal and external fault current that may occur. Breaker failure is normally detected by a settable current/time delay check in each phase. When the current exceeds the limit, this is recognized as a breaker failure. The overcurrent check should cope with both internal and external faults. It should handle DC transients and harmonics to improve security of the BF protection.

Consider Example 1, and notice that the minimum expected through-fault current for an external fault is 200 A. With an internal busbar fault this value is 175 A. This means that the CBF should be set more sensitive than the minimum of these two values. This overcurrent stage could be set as 0,25 x In = 0,25 x 500 A = 125 A, which is sensitive enough and has a 30% margin towards the 175 A. The overcurrent check sensitivity is typically from 10% of the nominal CT current.

13.2.5 Setting multifunctional IEDs

Modern numerical BBP devices are multifunctional IEDs the same as other numerical unit protections and, like other modern protections, BBP contains much more detailed setting possibilities than the old BBP relays. With these IEDs, in addition to the tripping characteristic, it is possible to set different functions/protection elements like bus zone (BZ), check zone (CZ), high resistance earth fault, CBF (Circuit Breaker Failure) mode of operation, voltage supervision, different parameter groups, etc. Some of these multifunctional relays may even be used on other units such as transformers, generators, motors, autotransformers, shunt capacitors, etc. Thus, these BBPs could include the setting of inrush current with 2nd harmonic, n-th harmonic, cross-blocking, etc – parameters that are normally set if the device is to protect a unit other than a busbar. These numerical software functions may easily be enabled/disabled – depending on the kind of unit that is protected. This type of modern feature is typical of a multifunctional IED; thus, providing the user with more setting possibilities. But, this again demands that the user be more knowledgeable and experienced to know when/where to use the functions and when/where to switch them OFF.

13.2.6 Open CT

Some modern BBP relays have a feature for detecting open CTs. The logic may detect the instant in time when a CT already connected is open-circuited. The action is to block the affected phase, and produce an alarm. The user has to set a value for the minimum expected through-load current drop for open CT detection. This level should be set as high as necessary to prevent spurious blocking due to the false differential current caused by CT errors, but as low as necessary to detect the open circuit condition for the smallest loaded CT connected to the differential zone. If the minimum load current is not available or if the load current is too small when compared to the differential current present due to CT errors from the use of different types of CT in the same substation, this value may be settled in between 20%-80% of the rated primary current of the CT with the smallest ratio.

In the case of example 1, the current level to detect open CT may be set as:

From the smallest CT ratio present in the substation, the current level is settable in steps between 100 A to 400 A –- corresponding to 20%-80% of the rated primary current.

From the smallest load current present in the substation the current level is set to 140 A.

The value of 140 A is appropriated for the setting since it satisfies both conditions.

14 IEC 61850 Standard

The IEC 61850 standard consists of ten major sections that standardize communication networks and systems in substations to allow interoperability of devices from different manufacturers. IEDs connected to the substation LAN can exchange information with the substation control system or with each other. For BBP interoperability, the IEC 61850 standard specifies only Logical Node Class PDIF, which is common for all types of differential protection. For example, BBP application issues such as splitting and/or merging of Zones are not covered by this standard at this time.

IEC 61850-8-1 (station bus) standardizes communication services between IEDs and substation control system that can also be applied to BBP. Information that can be provided to the supervisory system may include analogue measurement data (bay-wise and zone-wise quantities), alarms, disturbance recording and event list.

GOOSE messages can be used to exchange information between different IEDs and BBP such as CBF starting, auto-reclosing blocking, bay inter-tripping, and primary apparatus status. Another application can be for blocking/releasing signals for simple busbar blocking schemes.

IEC 61850-9-2 (process bus) defines communication between merging units (that interface instrument transformers and process bus) and IEDs. With this approach, IEDs connected to the process bus receive sampled analogue values (currents and voltages). However, as of now, there is no readily available BBP relays that can operate based on data available on the process bus.

15 Testing

15.1 Introduction

The scope of this section does not include Conformance Tests. These are covered comprehensively in National and International Standards and other Cigré Working Group documents.

Protective relay testing generally consists of three steps:

- Factory Acceptance Tests (FAT), if requested
- Commissioning Tests or Site Acceptance Tests (SAT)
- Periodic Tests

The testing of numerical busbar protection has many aspects in common with the testing of conventional busbar protection with the distinct exception in respect to communications and the way in which the tests themselves are performed. The method of performing tests is modified in view of the following:

- Additional internal information, such as individual bay current magnitudes primary apparatus status etc., is available which can be used for the tests. This reduces the need for external measuring apparatus
- Additional functions, such as CBF, are integrated into one device making a protection scheme testing approach necessary.
- As multifunction protection permits the integration of a much larger part of the scheme, (wiring, additional relays etc.) it is possible that a larger part of the scheme tests are realized in a pre-commissioning phase, e.g. during factory tests.

15.2 Factory Acceptance Tests

The panel manufacturer normally performs a minimum of wiring and dielectric tests in addition to which functional checks and calibration of the busbar protection scheme could be made before shipment. The end user or one of his representatives may request to witness the FAT to check that all requirements are fulfilled by verifying some protection element operation and the dynamic substation replica (by simulating disconnector/CB open/closed position). These are conducted to prove that relays are free from defects during manufacture and that the protection scheme works as intended (circuit breaker failure protection, differential element, CT fail supervision, etc.).

As not all components and interfaces of the system may be available or cannot be simulated in the factory, additional commissioning tests should be performed at site (site acceptance test) to verify proper connection of the relay to the power system and all auxiliary equipment.

15.3 Commissioning Tests or Site Acceptance Tests

Even though the scheme has been thoroughly tested in the factory, the external wiring/cabling on site (e.g. CT’s, VT’s, tripping circuits and switchgear auxiliary contacts) may have been incorrectly executed, or the CT’s / VT’s or switchgear auxiliary contacts may have been incorrectly installed. The impact of such errors may cause either unwanted operation of the busbar protection or failure to clear an internal fault.

Commissioning tests at site are therefore invariably performed before a busbar protection relay is put in service. The aims of the commissioning tests are:

- To ensure that the equipment has not been damaged during transport or installation
- To ensure that installation work has been carried out correctly (connection to primary and auxiliary equipment)
- To prove the correct operation of the busbar protection scheme as a whole

The main commissioning tests performed on the busbar protection are as follows:

- Testing of all ac and dc connections (digital input/output contacts and ac inputs – VT and CT)
- Testing main CT ratios, polarities and magnetizing curves
- Checking that CT ratio and polarity within the BBP are correctly compensated
- Checking of the interconnection between all equipment in the bay and between bays is correct,
- Checking that all primary equipment (disconnectors, isolators, circuit breaker, etc.) and timing of their auxiliary contacts for dynamic bus replica operate as intended
- Checking that all other equipment (external BF, line protection trip command, etc.) operate as intended
- Checking the setting and operation of all protection elements (differential, circuit breaker failure, etc.),
- Checking the communication interfaces including intertripping and SCADA interfaces if available
- Completion of secondary and primary injection testing

The end user may witness the SAT to verify that all requirements have been fulfilled by checking the final system.

Commissioning work must also be properly documented for future reference or future extension of the busbar protection scheme.

15.4 Periodic Tests

Traditionally, periodic tests were referred to as maintenance tests. Today, periodic test is a more appropriate name because modern numerical relays practically require no maintenance. After the protection system installation, periodic tests are performed at specified time intervals to check the overall protection system conditions and performance. Periodic tests may include verification of protection performance, the supervision system, setting conformance, and verification of components that are not supervised.

Periodic test time intervals may be specified as a definite time interval independent of other factors, or may be related to operational factors such as number of protection operations and character of faults. Time intervals may also be related to the protection technology and the utility regulatory rules.

BBP features can be used to simplify periodic testing as compared with traditional solutions based on electromechanical or static protection relays. BBP relays use extensive self-testing routines and include detailed metering, disturbance recording, and sequence of events. BBP can be programmed to activate disturbance recording for external faults and record the substation currents and voltages, isolator replica, bias and differential currents, CBF protection operation, and/or other elements of interest. Even though the BBP does not operate during these events, these records can be used to evaluate the BBP performance factors such as plausibility of current measurement, isolator replica, and stability of the BBP scheme. This information can also be used to determine the required time interval between periodic tests.

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