Relay protection of distribution networks

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Protection and Control of Distributed Energy Resources

Chapter 2

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Choose yourself and new technologies

HUMAN CAPITAL
HUMAN – BEST INVESTMENT!
Wrocław University of Technology
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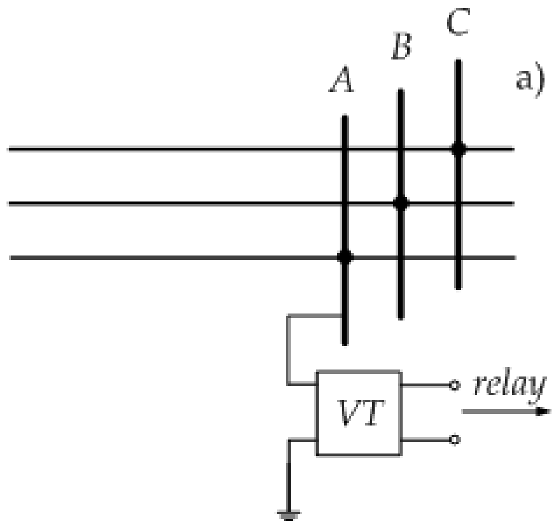
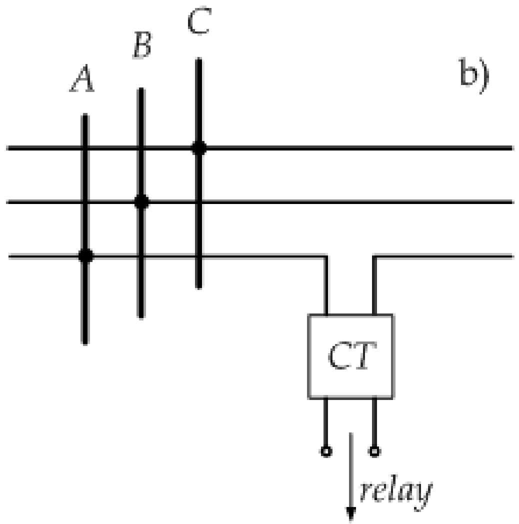
INSTRUMENT TRANSFORMERS

1. Voltage (Potential) Transformers (VTs, PTs) **are much like small power transformers, differing only in details of design.**
2. Current Transformers (CTs) **have their primary windings connected in series with the power circuit.**





MAIN TASKS OF INSTRUMENT TRANSFORMERS

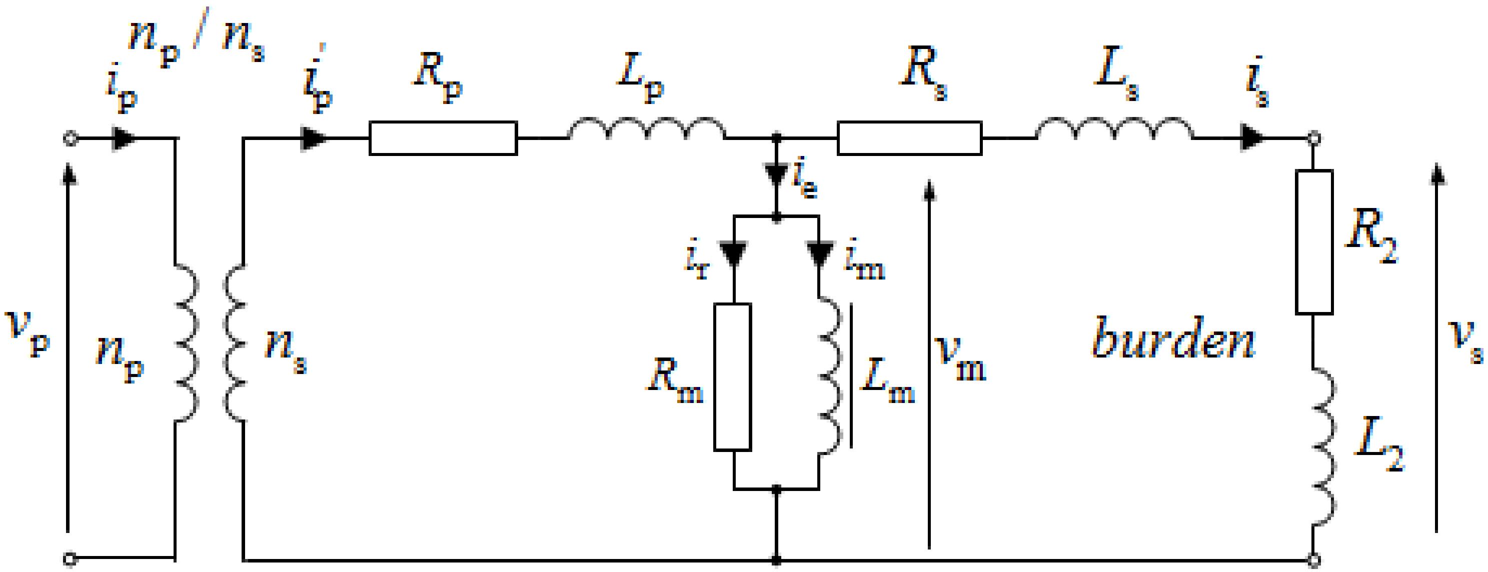
1. **To transform currents or voltages from a usually high value to a value easy to collect and process for relays and instruments.**
2. **To insulate the metering circuit from the primary high voltage system.**
3. **To provide possibilities of standardizing the instruments and relays to a few rated currents and voltages.**

INSTRUMENT TRANSFORMERS

In both cases the transformer can be represented by the equivalent circuit of below figure.

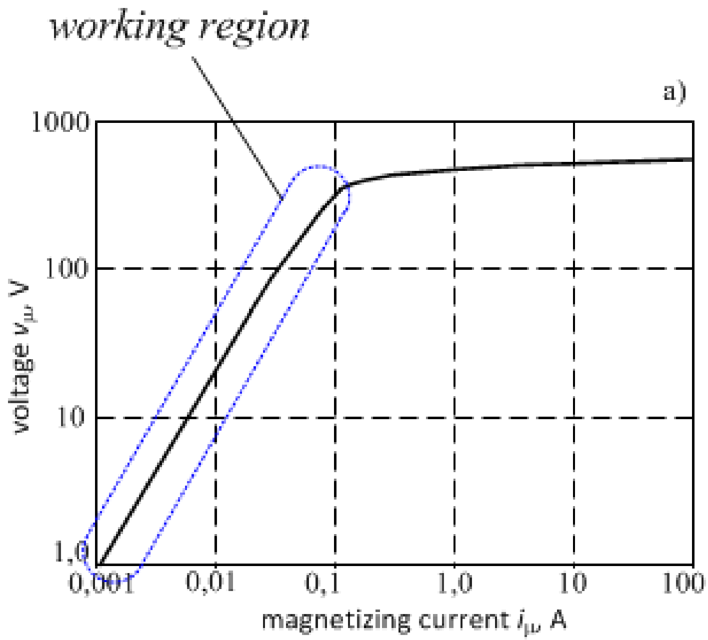
$$\frac{n_p}{n_s} = \frac{V_{pN}}{V_{sN}}$$ - for VT

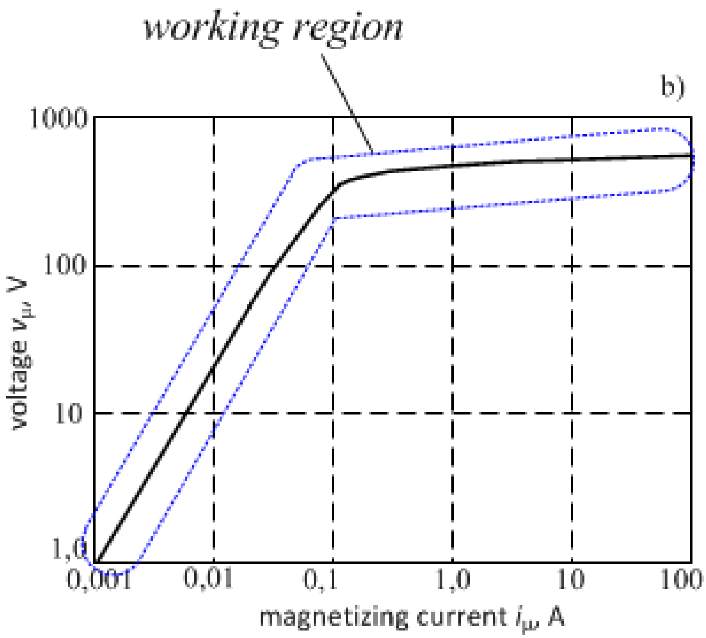
$$\frac{n_p}{n_s} = \frac{I_{sN}}{I_{pN}}$$ - for CT



INSTRUMENT TRANSFORMERS

Main source of error: magnetizing current.





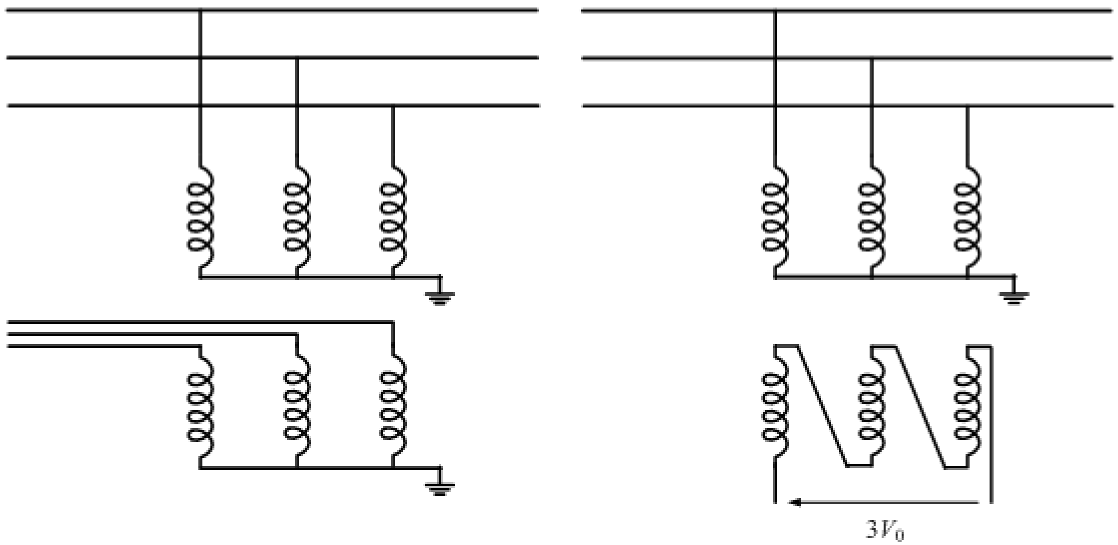
$$\phi = K\int_{t_1}^{t_2} v_m \mathrm{d}t$$

For VTs: $0 \le V \le 1.2V_N$

For CTs: $0 \le I \le 150I_N$

VOLTAGE TRANSFORMERS

a) b)



Typical VT for use on MV system

VT for phase – phase voltage (a) and for zero-sequence voltage measurement (b);

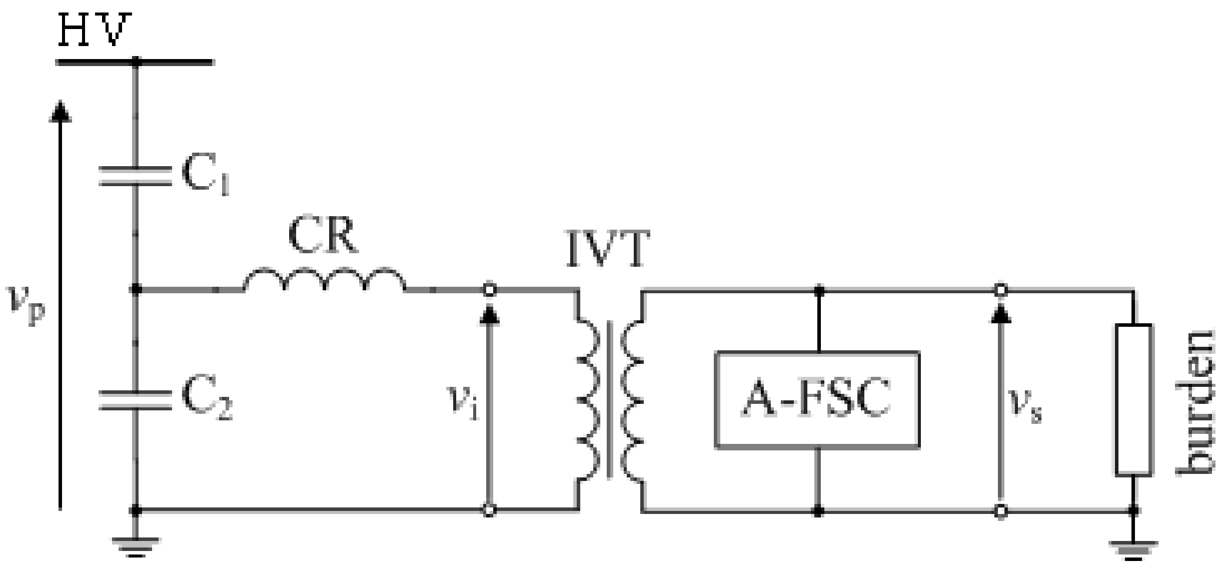
$v0 = (va+vb+vc)/3$

VOLTAGE TRANSFORMERS

1. **Typical secondary voltage: 120V (phase-to-phase) or 69.3V (phase-to-neutral).**
2. **For electromagnetic VT error is negligible for all practical purposes in its entire operating range – from 0 to about 120% of its normal rating.**
3. **Electromagnetic transformers are frequently sources of ferromagnetic phenomena in primary circuit.**

CAPACITOR VOLTAGE TRANSFORMERS

The Capacitor Voltage Transformers (CVTs) are often more economic for voltage V ≥ 220kV



C_1, C_2 – stack capacitors,

CR – compensating reactor,

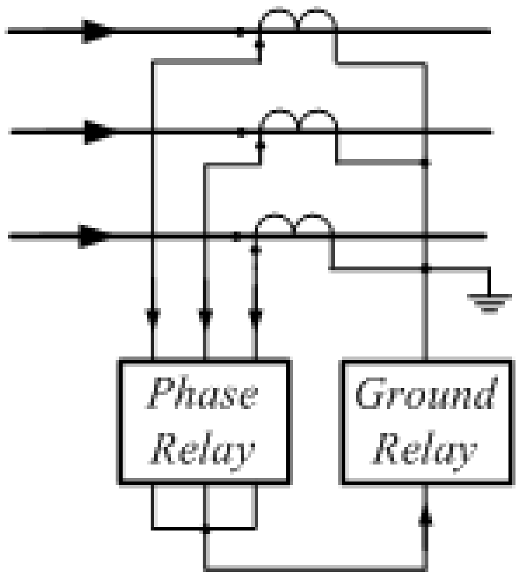
IVT – inducting step-down transformer,

A-FSC – anti-ferroresonance suppressing circuit.

CURRENT TRANSFORMERS

Typical CT for use on MV system, bushing type

Typical CT for use on LV system, wound type

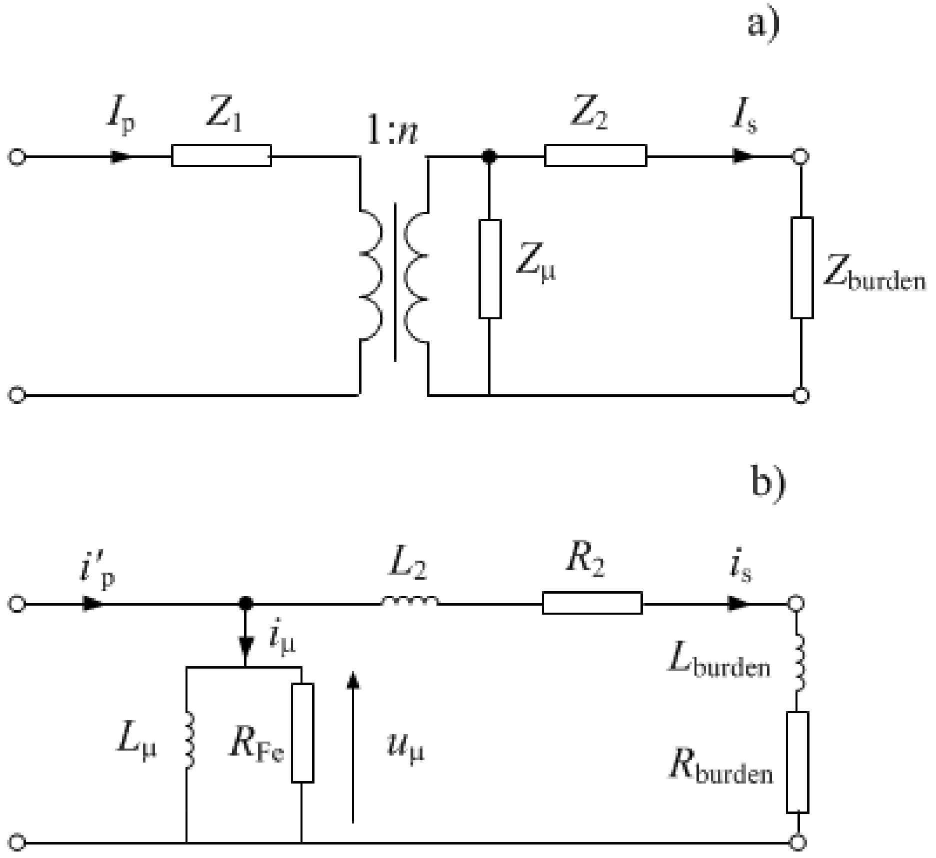


Typical connections of CTs

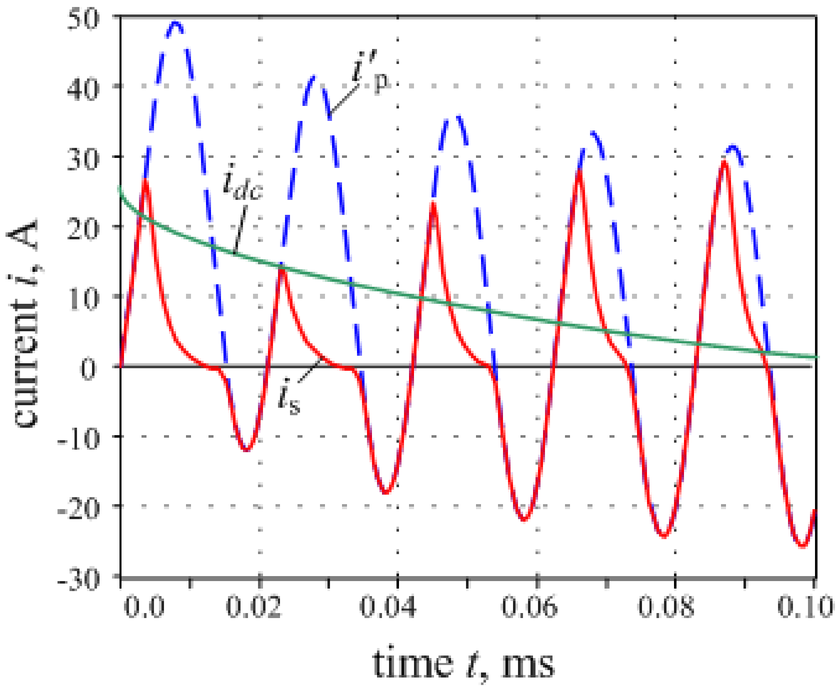
CURRENT TRANSFORMERS

CT bushing type, 110kV

CT transient errors



CT equivalent schemes

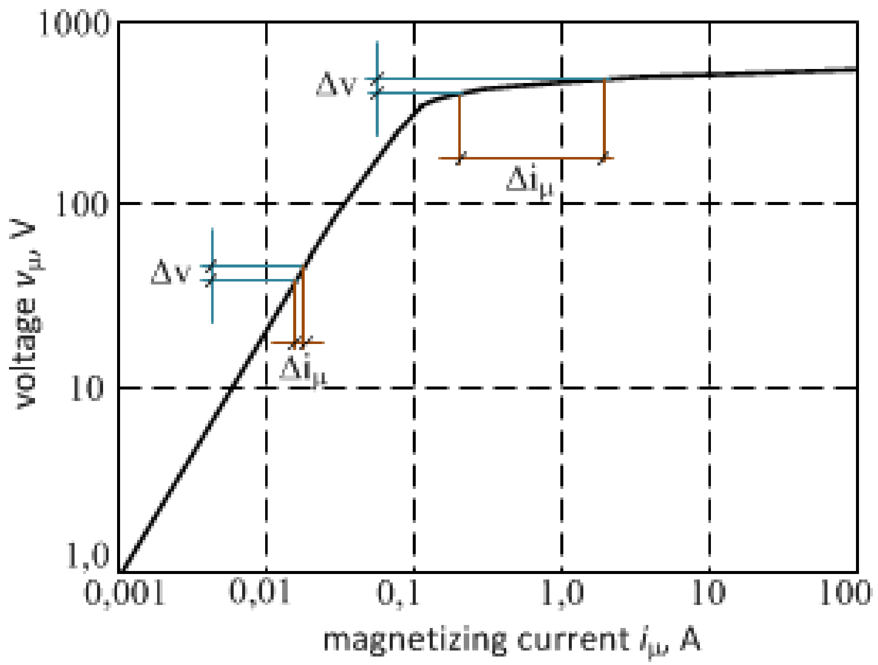


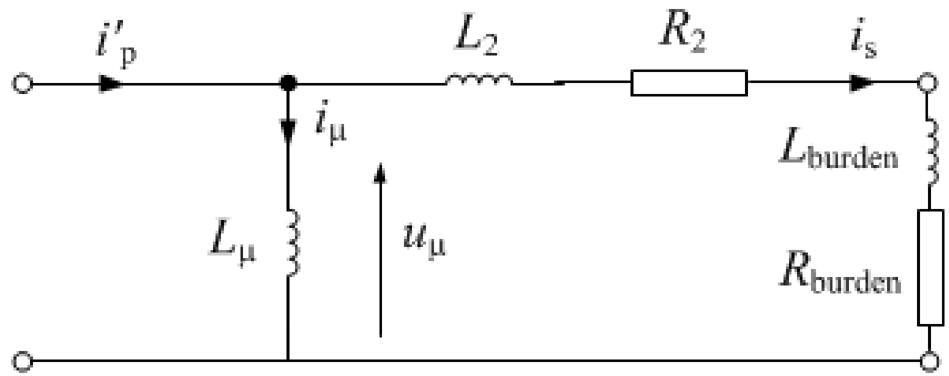
i'_p – equivalent primary current;

i_{dc} – decaying dc component;

i_s – secondary current;

Mechanizm of CT saturation

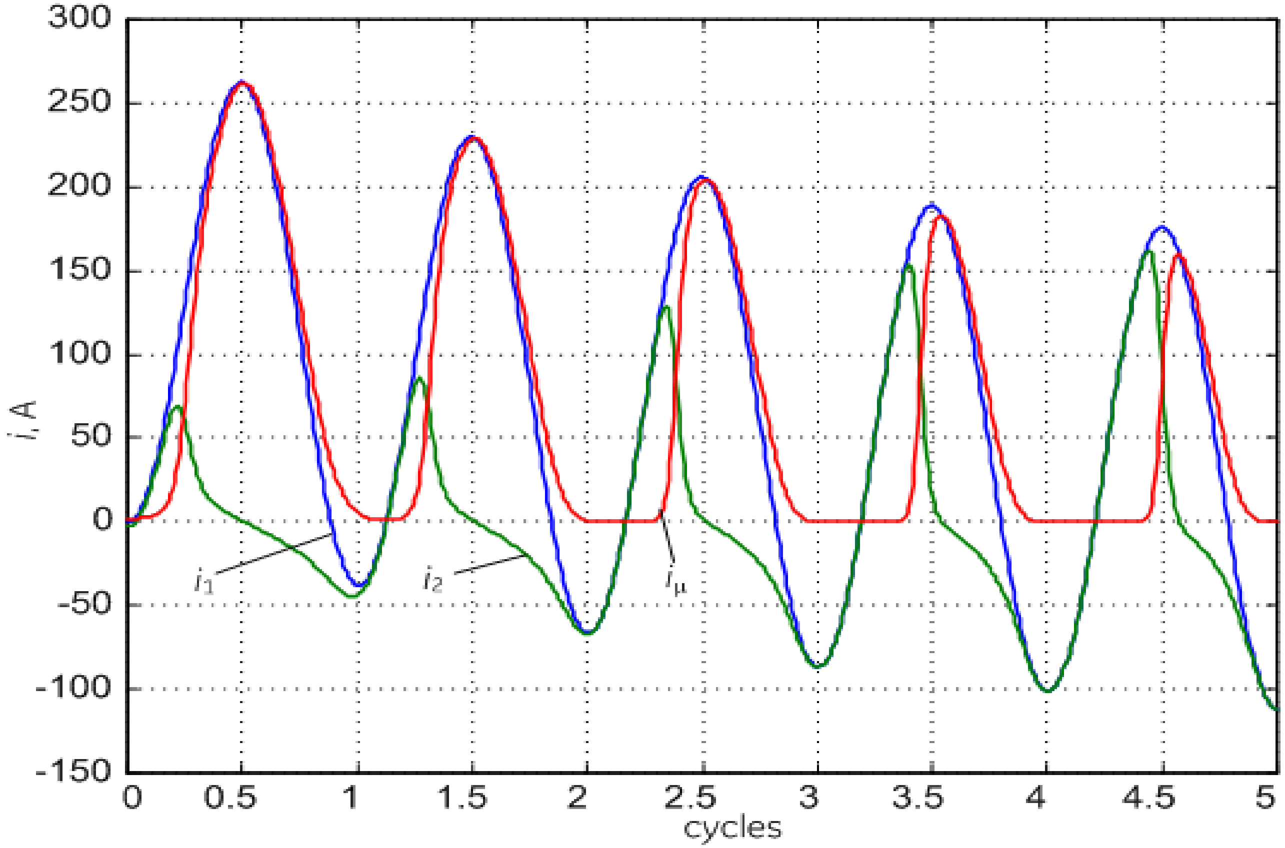




$$i_s = i'_p + i_\mu$$

Magnetizing characteristic

CT transient errors



***i_1* –primary current; *i_2* – secondary current; *i_μ* – magnetizing current;**

CTs accuracy class

IEC60044-1 commonly define protection current transformers in terms of composite error at an accuracy limit factor.

The classification of protection current transformers follows the following simple formula:

"10 P 10", e.g.: 600/1, 10VA, 10P10

Number before letter indicates composite error achieved in percentage terms

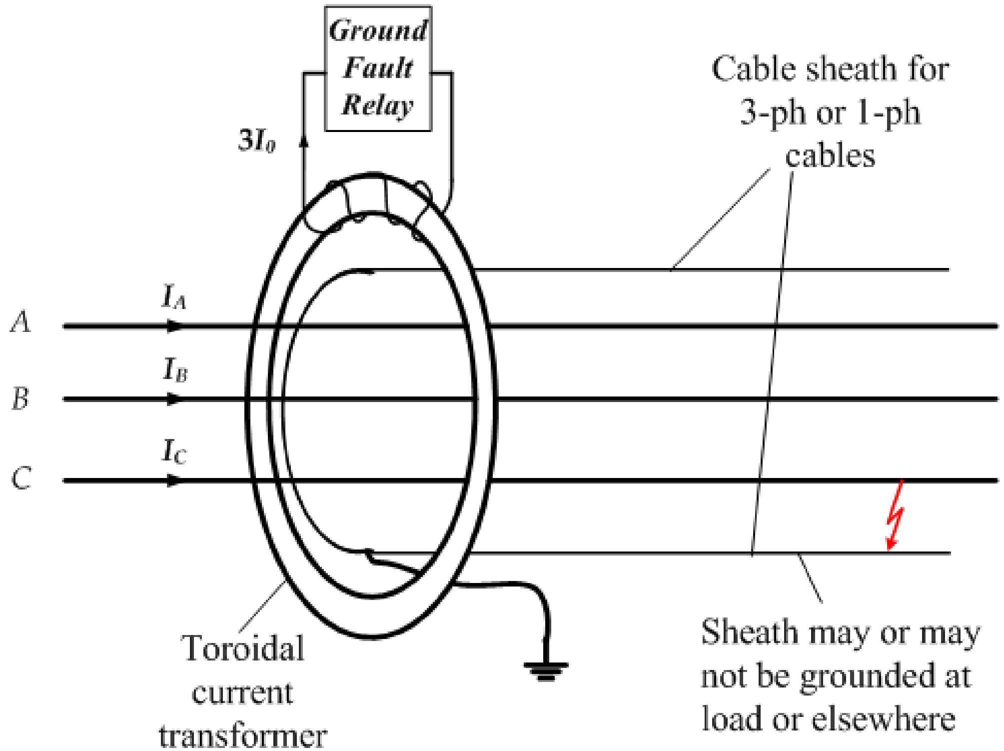
'P' for Protection

Number after letter indicates factor of primary current up to which composite error will be achieved

Example:

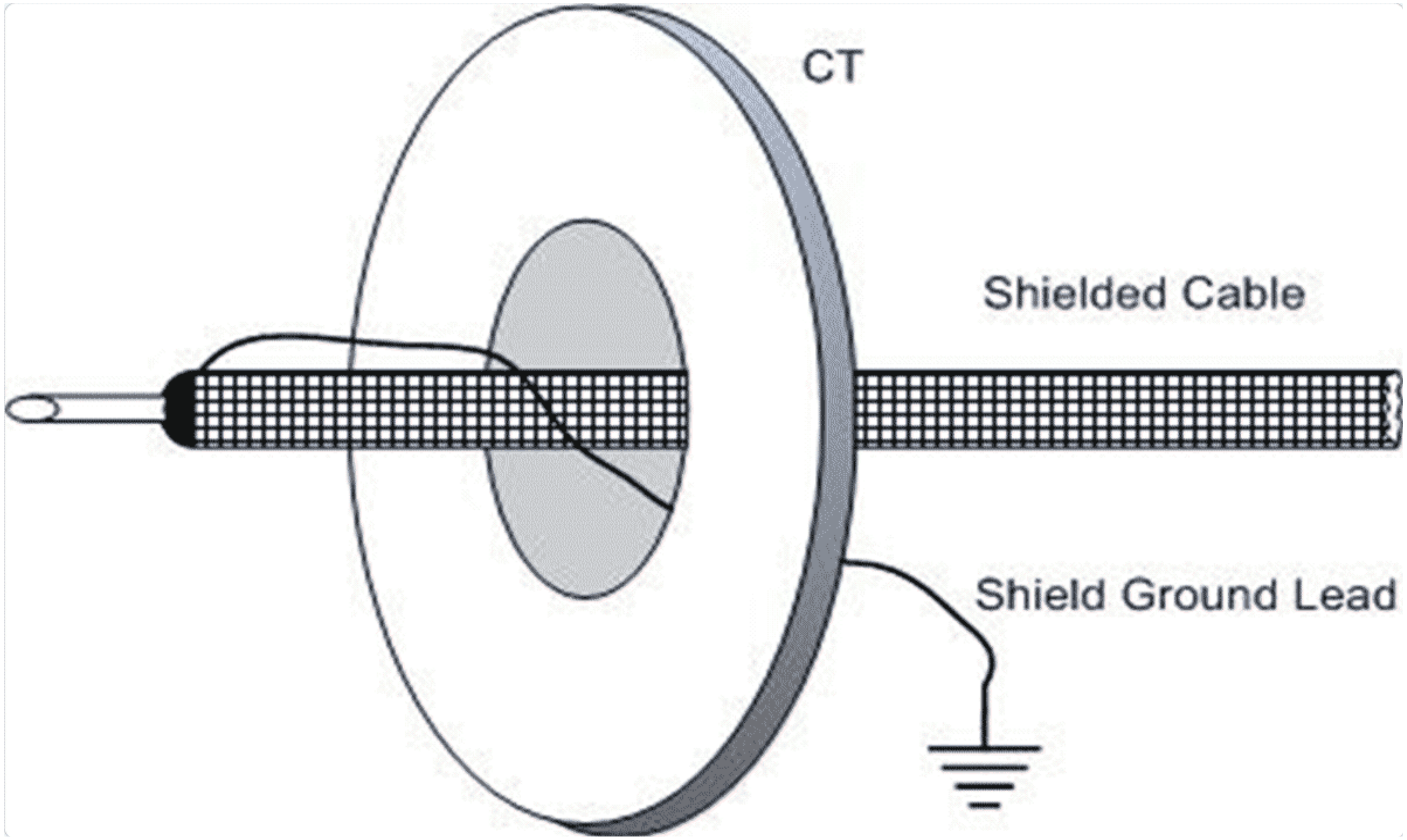
5P10 - current transformer will have a ratio error of 1% and phase error not exceeding 60 minutes; this will achieved for current 10 times greater than nominal value.

CURRENT TRANSFORMERS

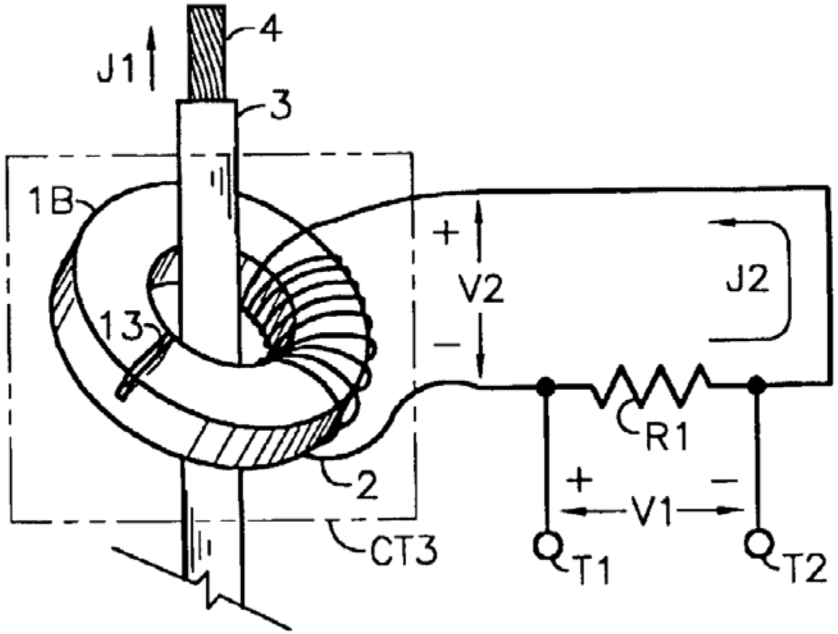


Typical application of the flux summation current transformer for ground-fault protection with metallic sheath conductors, Ferranti type

CTs installed over shielded cables

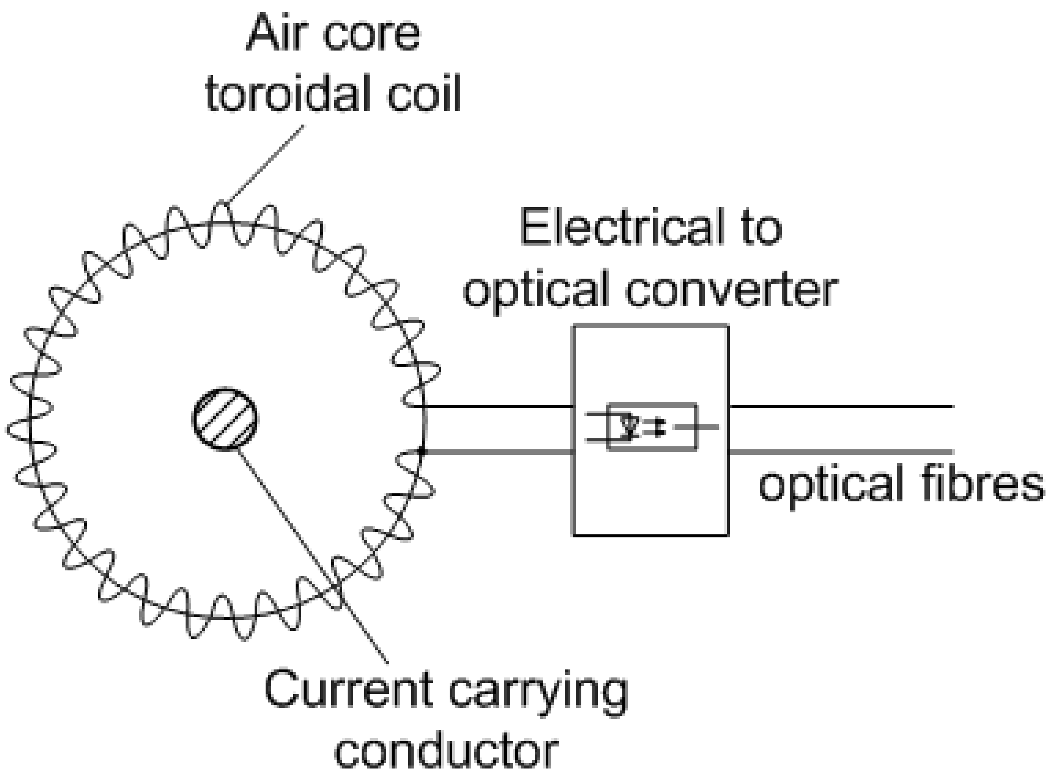


CURRENT TRANSFORMERS



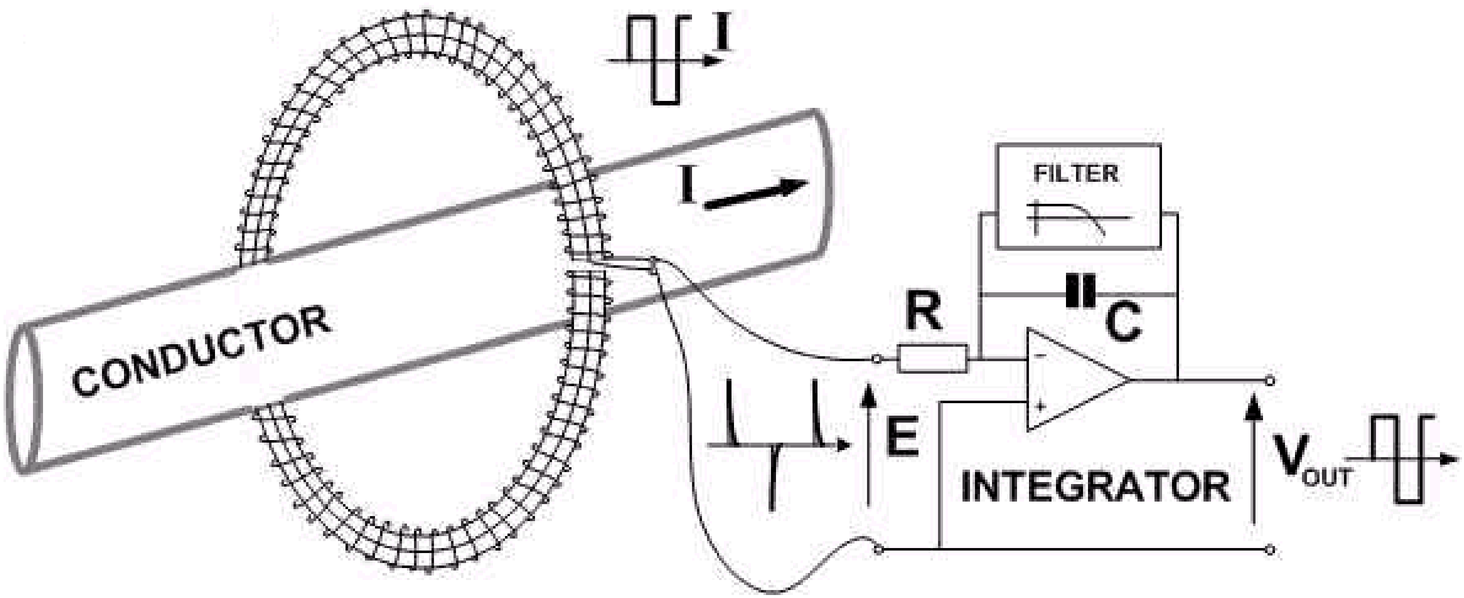
Typical application of the CT for cable network

CURRENT TRANSFORMERS



Rogowski coil for current sensing

Rogowski coil



$$E = H\frac{\mathrm{d}I}{\mathrm{d}t} \qquad V_{out} = \frac{1}{RC}\int E\,\mathrm{d}t$$

H* – coil sensitivity, Vs/A; V_{out} is proportional to *I

Line Protection

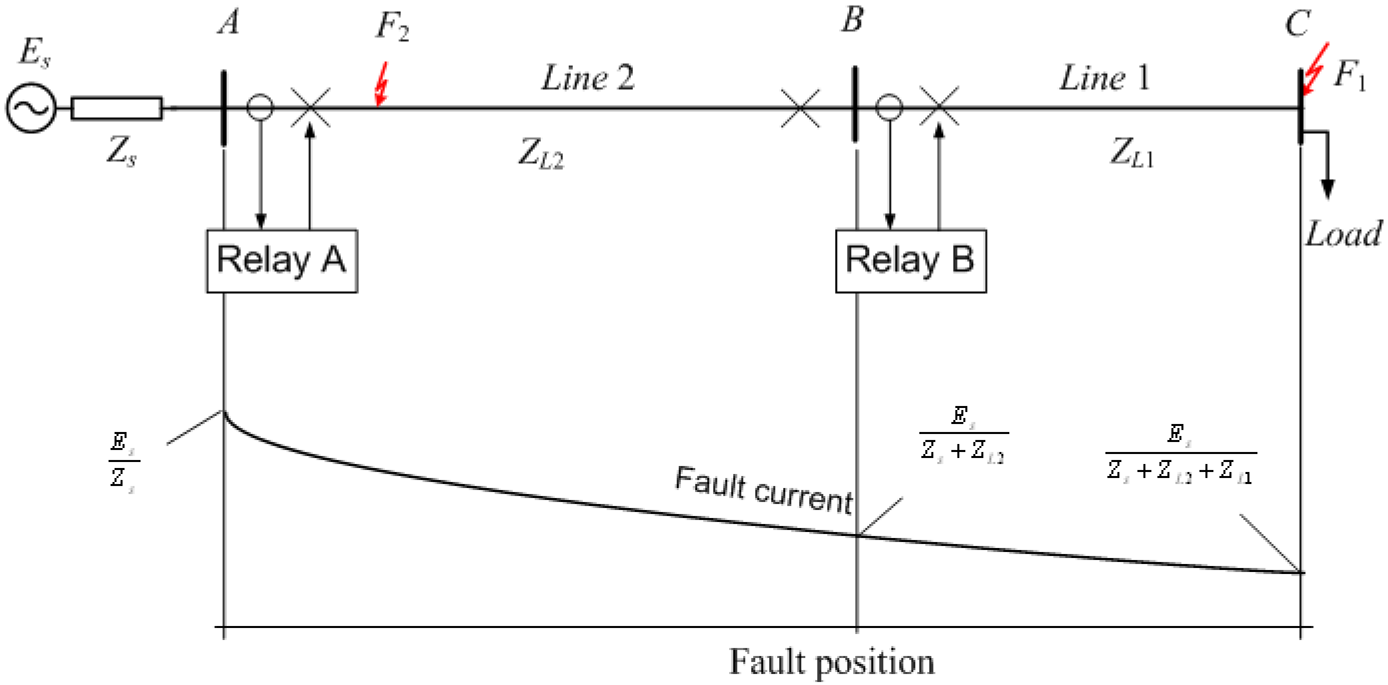
Objects

- Phase fault protection
- Earth fault protection
- Auto-Reclosing
- Distribution Network Protection
  - ungrounded system
  - resonant grounded system
  - high-resistance grounded system
  - effectively grounded …
- …

Technique

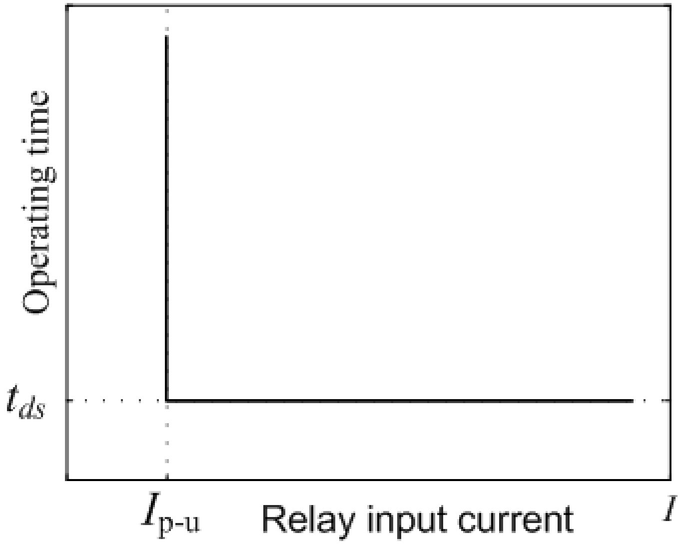
- Overcurrent Protection
- Directional Protection
- Negative-sequence Protection
- Unit Protection of Feeders
- Distance Protection
- …

Overcurrent (OC) line protection



- **Fault F_1 should be switched-off by Relay B.**
- **Buck-up protection for Relay B is realized by Relay A.**
- **Fault F_2 should be switched-off by Relay A.**

Defined Time Overcurrent Relay

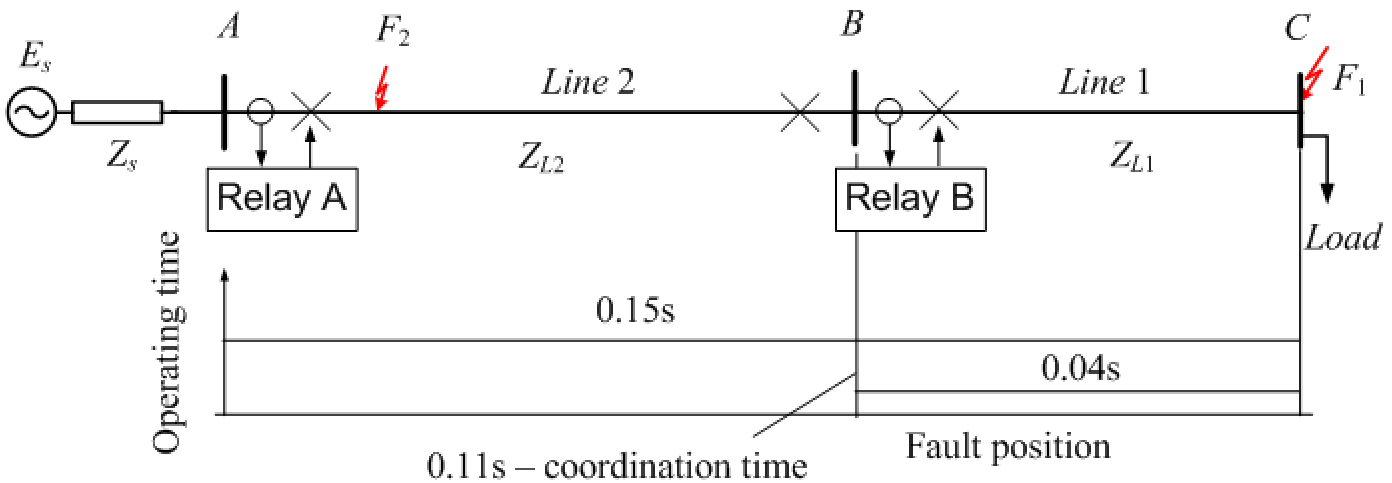


I_{p-u} – pick-up setting current;
t_{ds} – defined setting time delay.

Condition for relay switching-off:

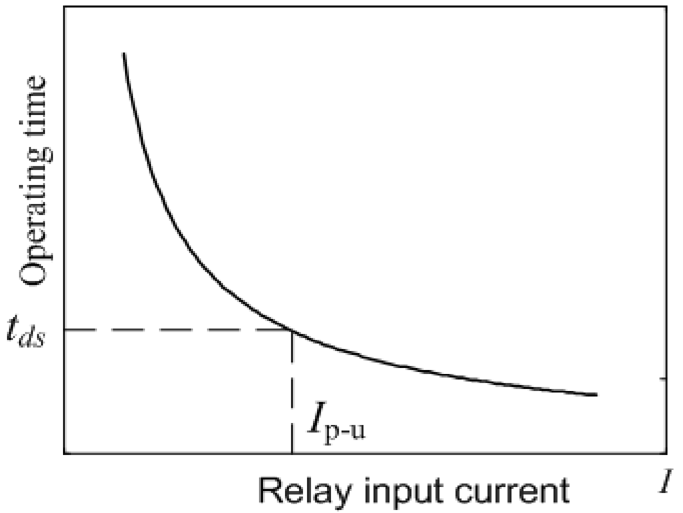
$I > I_{p-u}$ for time $t > t_{ds}$

Instantaneous OC relay when: $t_{ds} \approx 40$ ms



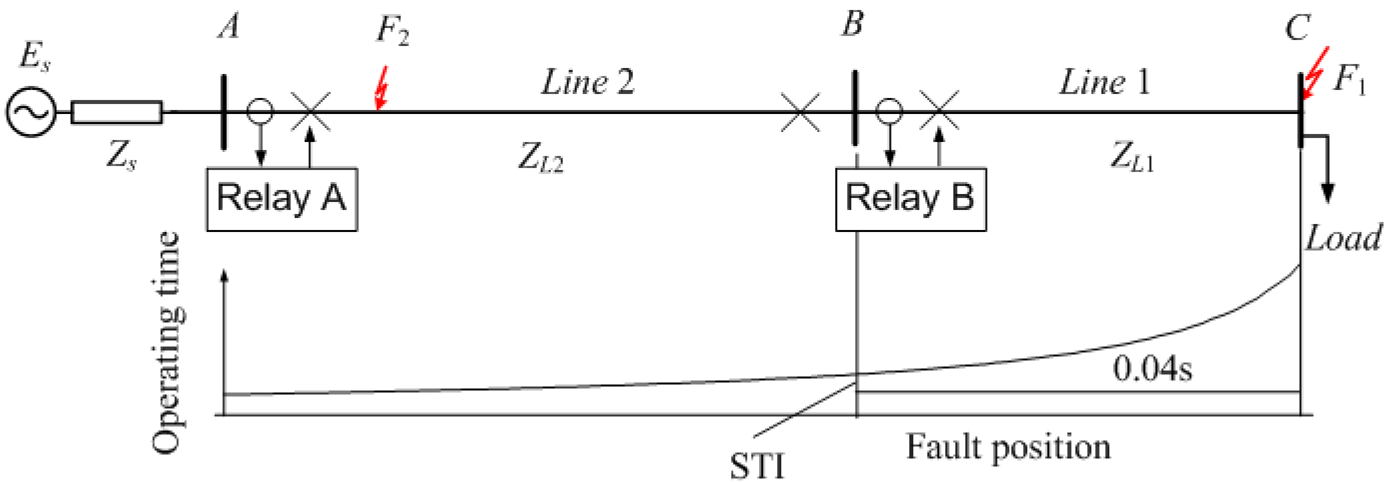
$I_{Lmax} < I_{p-u} < I_{F1min}$

Inverse Defined Minimum Time Overcurrent Relay



Values of $I_{p\text{-}u}$ and t_{ds} depend on fault current I.

STI – Selective Time Interval



Tripping time characteristics

	a	b	c	R
Per ANSI/IEEE C37. 112	Trip			Release
Moderately inverse	0.0515	0.0200	0.1140	4.85
Very inverse	19.6100	2.0000	0.4910	21.60
Extremely inverse	28.2000	2.0000	0.1217	29.10
Per ANSI	Trip			Release
Normally inverse	8.9341	2.0938	0.17966	9.00
Short time inverse	0.2663	1.2969	0.03393	0.50
Long time inverse	5.6143	1.0000	2.18592	15.75

$$k = 0.01\ldots10.00$$

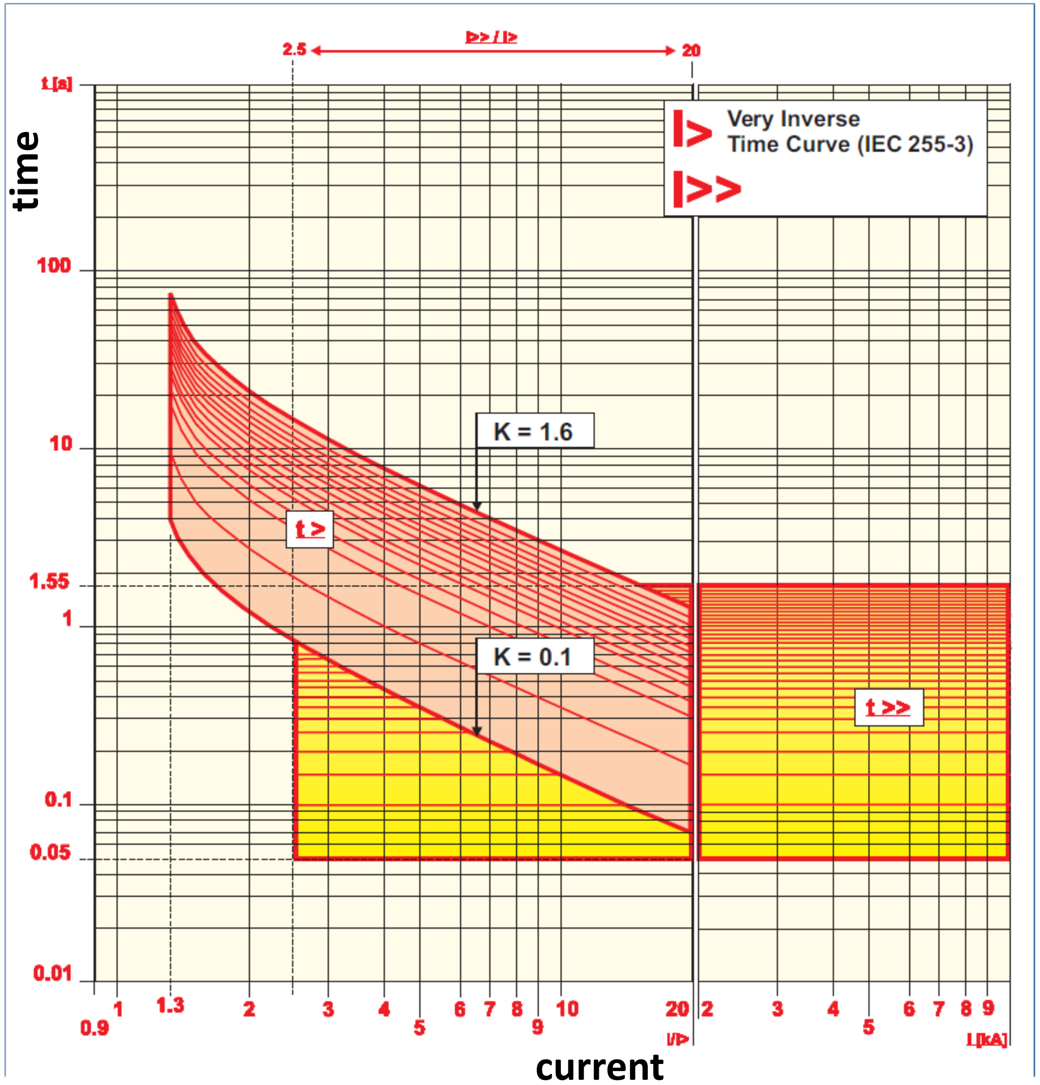
$$t = k\frac{a}{\left(\frac{I}{I_{ref}}\right)^{b} - 1} + c$$

$$t = k\frac{R}{\left(\frac{I}{I_{ref}}\right)^{b} - 1}$$

Tripping time characteristics - example

$$t = k\frac{a}{\left(\frac{I}{I_{ref}}\right)^{b} - 1} + c$$

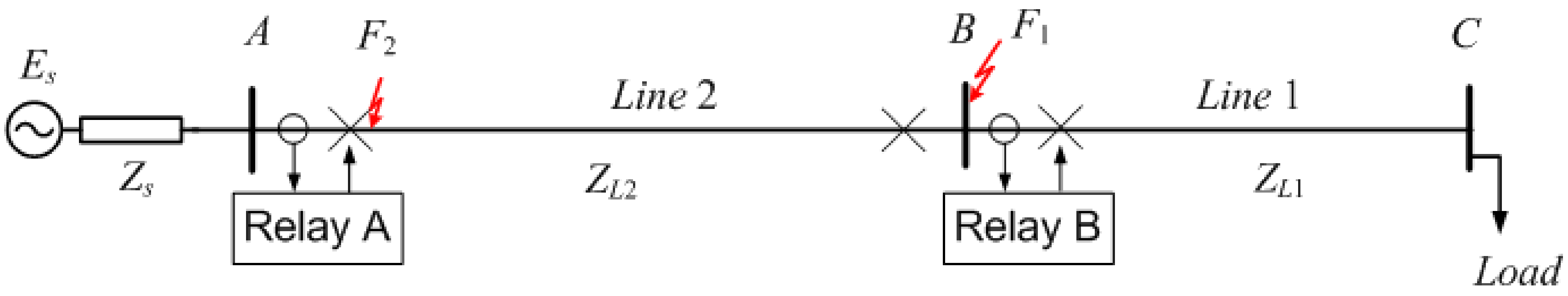
$$k = 0.01 \ldots 10.00$$



Instantaneous Overcurrent Relay

Adding instantaneous trip units to time-overcurrent relays provides high-speed relay operation for close-in faults and may also permit faster settings on the relays in the adjacent section. It may be applied under the following condition:

$$I_{F2max} > (1.1 \,..\, 1.3)\, I_{F1max}$$



Limitations of Traditional Overcurrent Relay

1. **Phase overcurrent relay must be set (pick-up current) above the maximum load current:**

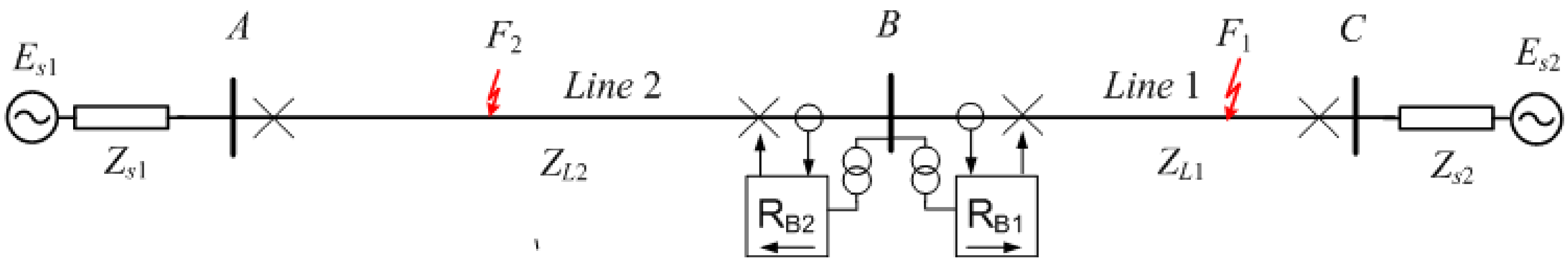
   $$I_{p\text{-}u} > I_{LoadMax}$$

   Therefore, max. load expectations limit the sensitivity and speed of the protection.
2. **Protection settings must be checked against load levels frequently and seasonally.**
3. **Ground overcurrent relays must be set above the max. load unbalance expected on the feeder.**

Directional Overcurrent Relay

When there is a source at more than one of the line terminals, fault and load current can flow in either direction. Relays protecting the line are therefore subject to fault power and reactive flowing in both directions.

Since directional relays operate only when fault current flows in the specified tripping direction, they avoid a coordination problem: relay R_{B1} protects only *Line* 1 while R_{B2} – *Line* 2.



Directional Overcurrent Relay

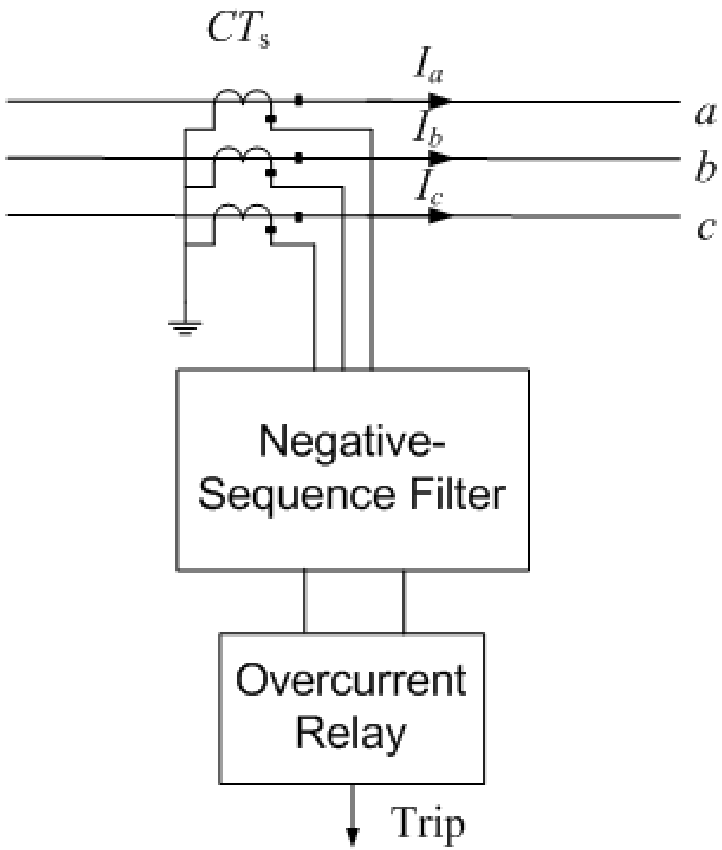
The directional measurement is performed with voltage polarization. The polarizing voltage is taken entirely from phase-ground voltages (phase-ground fault loops), or phase-phase voltages (phase-phase fault loops). The polarizing voltage $\underline{V}_{AM}$ (for all fault loops) is memorized voltage from the period before fault.

A fault direction is determined from the angle of fault-loop impedance:

$$-AngDir < angle\frac{\underline{V}_{AM}}{\underline{I}_{A}} < AngNegRes$$

where: the setting of *AngDir* and *AngNegRs* can be set to -15 and 115 degrees respectively.

Negative-Sequence Overcurrent Protection

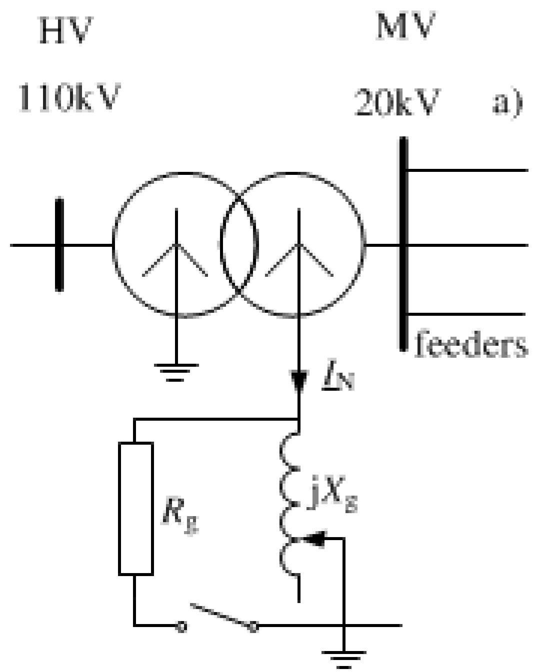


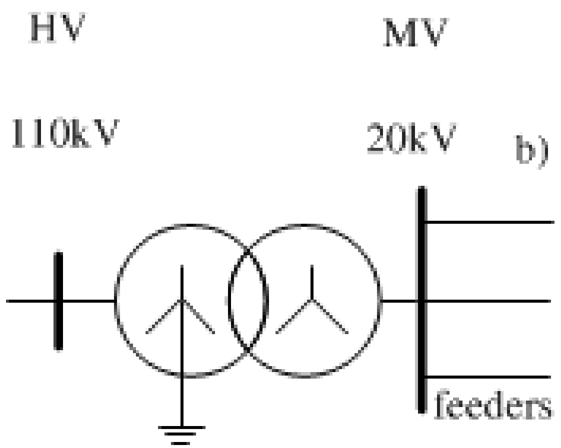
1. **Greater sensitivity and speed for phase faults – lower pick-up level.**
2. **Buckup for ground faults.**
3. **Easy to realize in microprocessor-based relays.**
4. **Easy understand, coordinate and set.**

Network System Grounding

System grounding is related to a method of system neutrals connection to ground. The following categories can be selected:

- **Effectively (solidely) grounded system;**
- **Resistance-grounded system;**
- **Reactance grounded system;**
- **Ungrounded (isolated) system.**

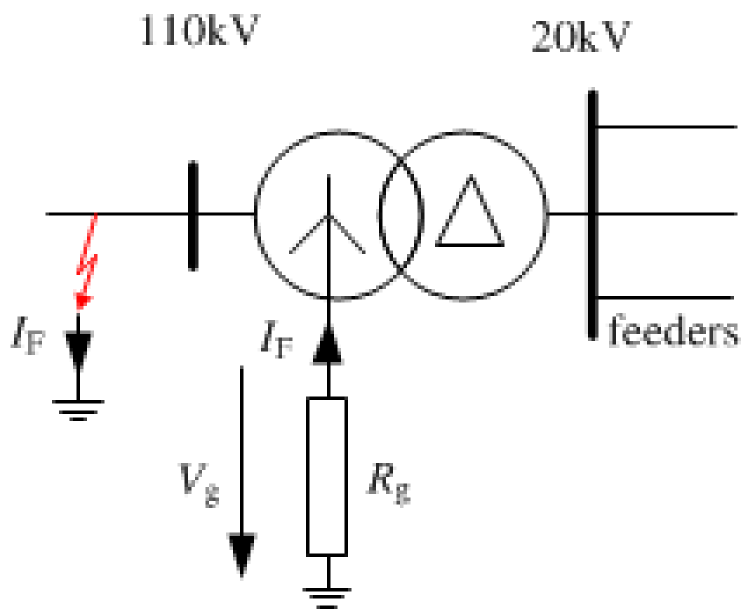




Network System Grounding

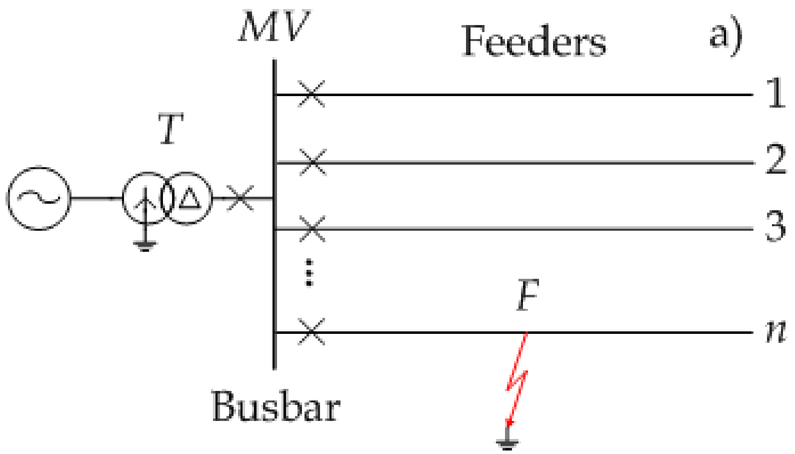
The principal purposes of grounding are to minimize potential transient overvoltages to comply with local, state, and national codes for personnel safety requirements; and to assist in the rapid detection and isolation of the trouble or fault areas.

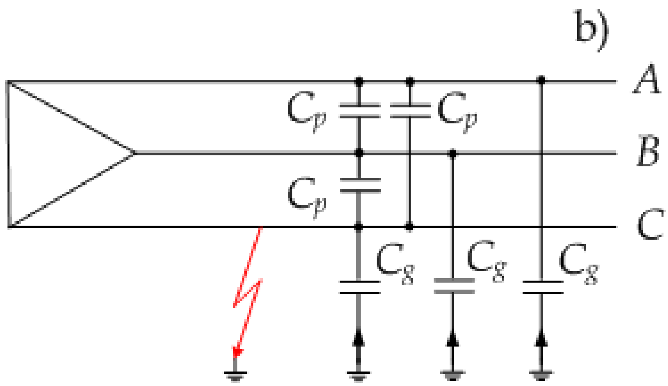
HV system is usually solidely grounded to prevent overvoltages during phase-to-ground faults.



Ungrounded System

In ungrounded systems there are no intentionally applied grounding. However, they are grounded by the natural capacitance of the system to ground. They are frequently applied in industrial supplying networks (e.g. in mine networks).

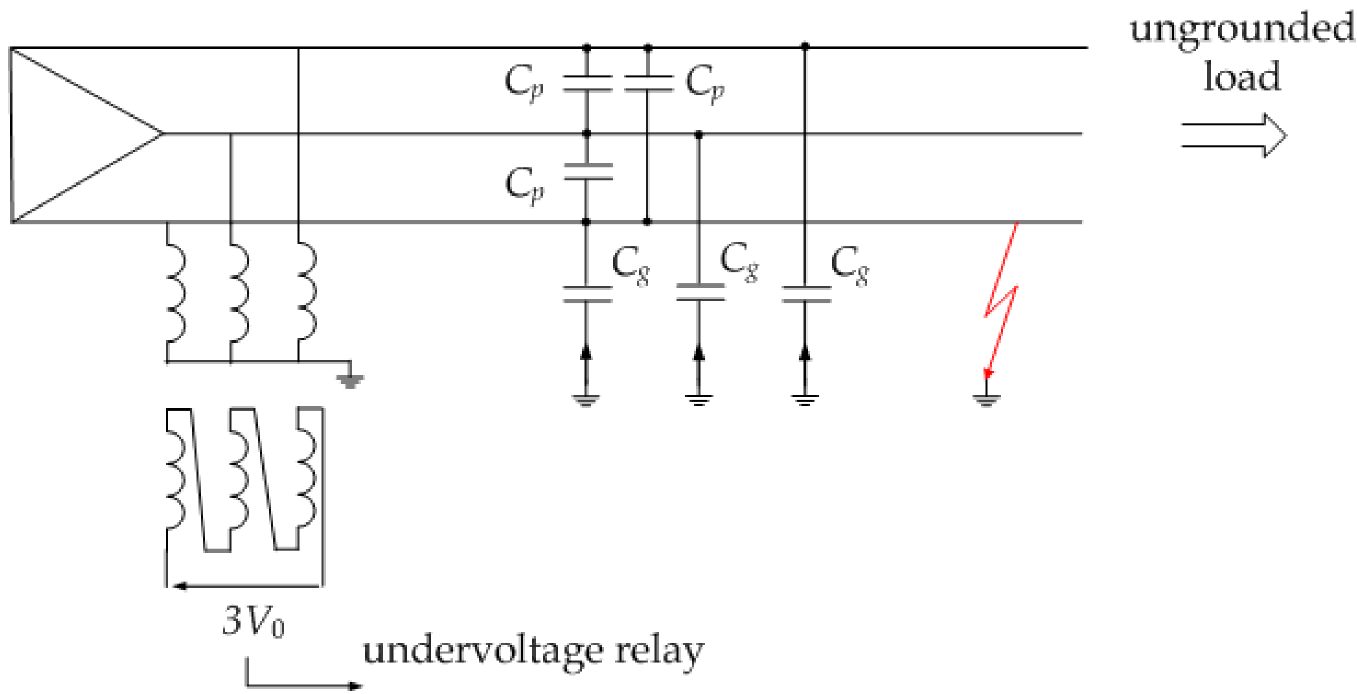




DN (MV) ungrounded network (a) and shunt capacitances (b)

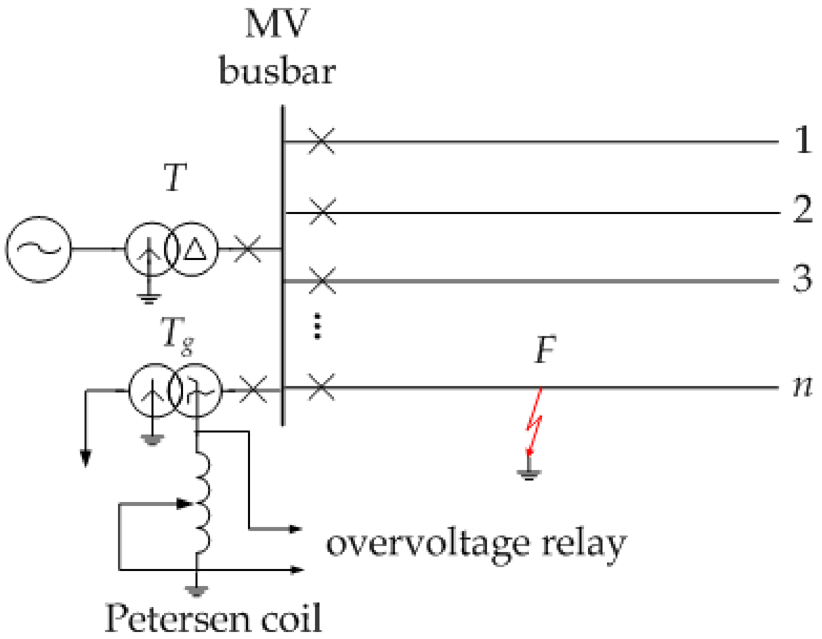
Ungrounded System – ph-G protection issue

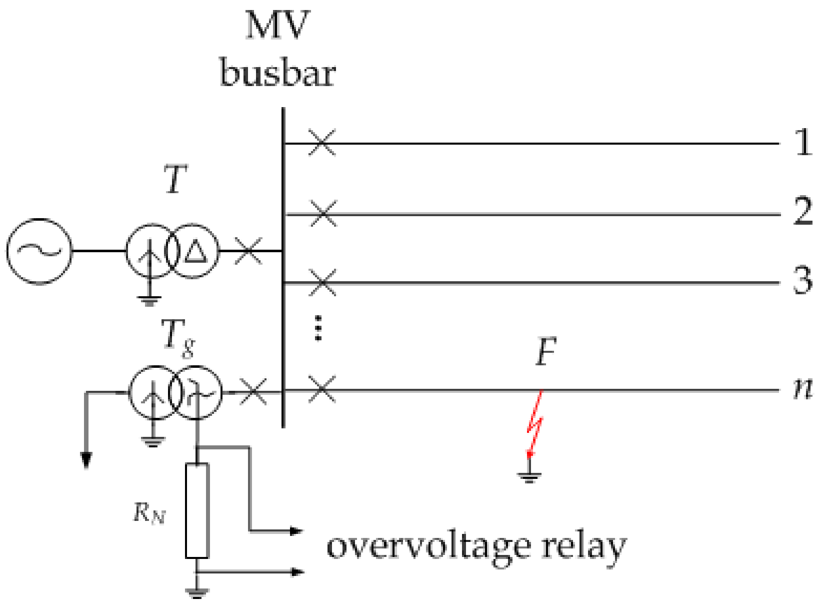
Voltage provides the best indication of a ground fault because the current is very low and, basically, does not change with the fault location. Problem with selection of a faulty feeder at the busbar.



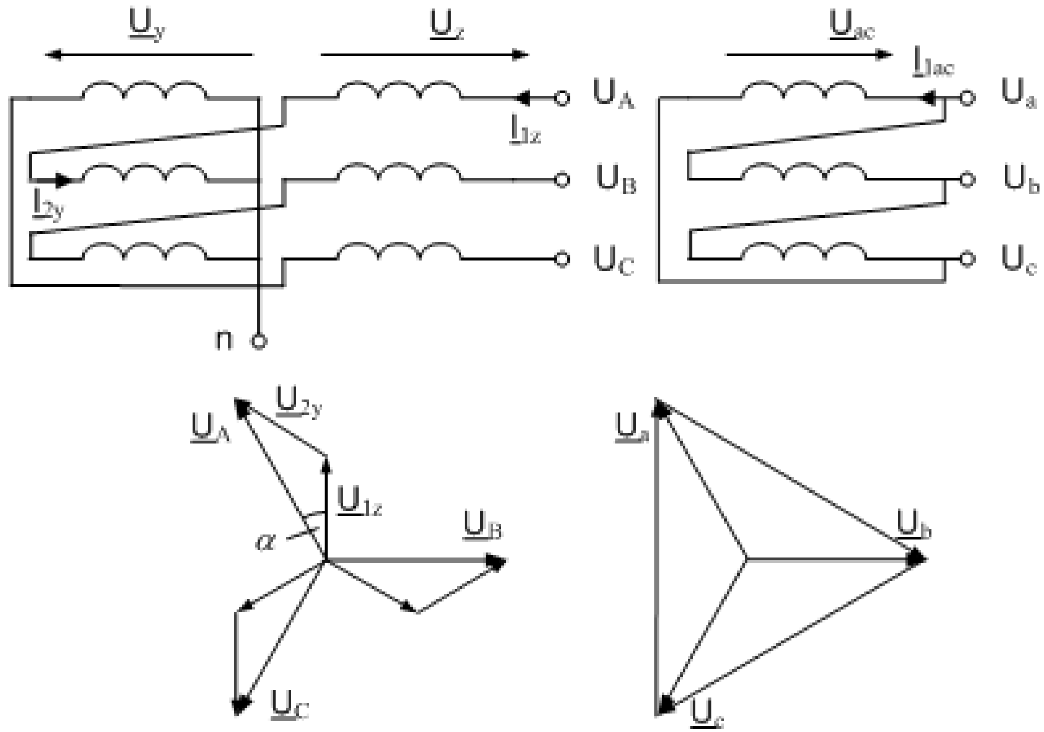
High-impedance grounding system

There are two types of high – impedance - grounding system: high-resistance and resonant grounding. High-resistance grounding is widely used in generator MV networks while resonant grounding is applied in OH, especially rural MV networks.





Zig-zag grounding transformer



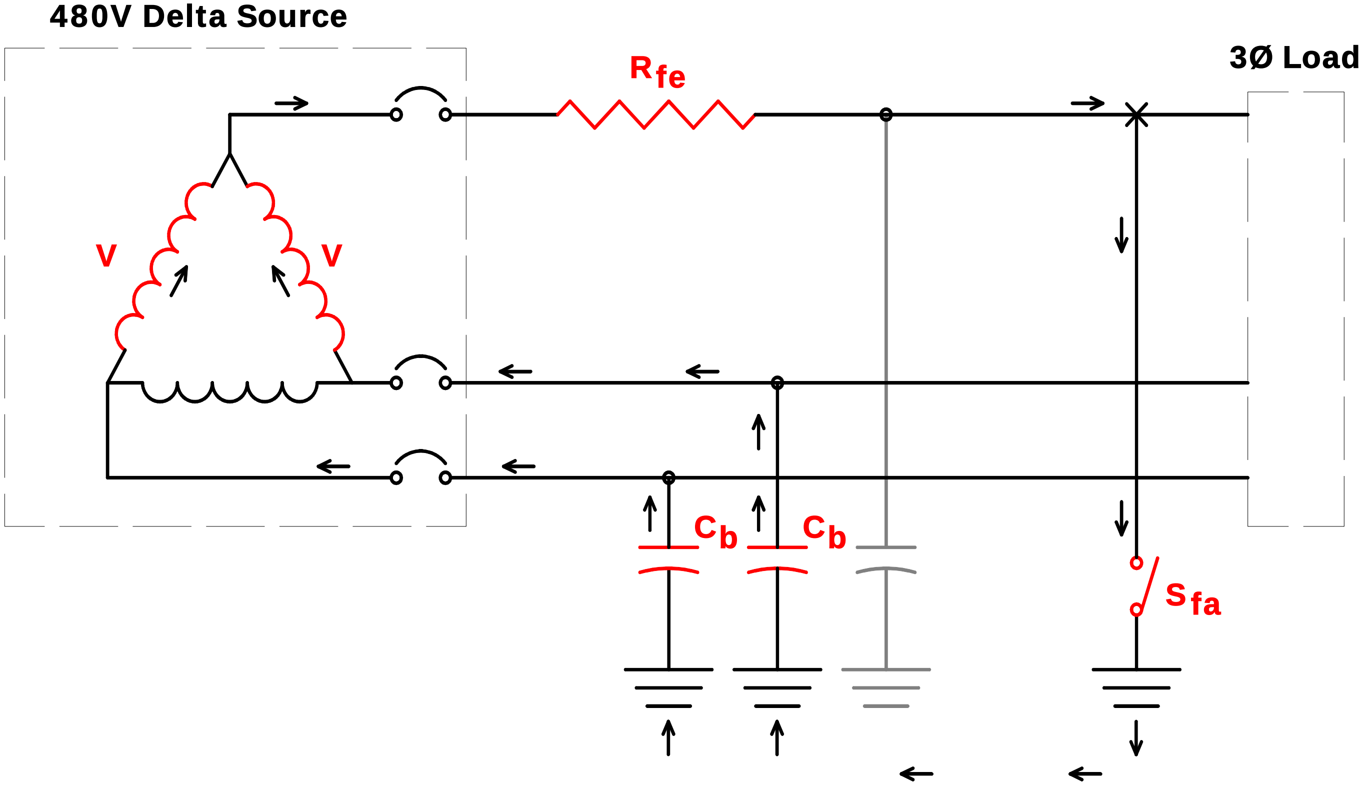
Winding connection and voltage vectors for Z/d 0 transformer

What is a grounding transformer?

- **It is used to provide a ground path on either an ungrounded Wye or a Delta connected system**
  - **The relatively low impedance path to ground maintains the system neutral at ground potential**
- **On Ungrounded systems you can have overvoltages of 6 to 8 times normal with arcing faults**

Arcing Ground Faults Intermittent or Re-strike

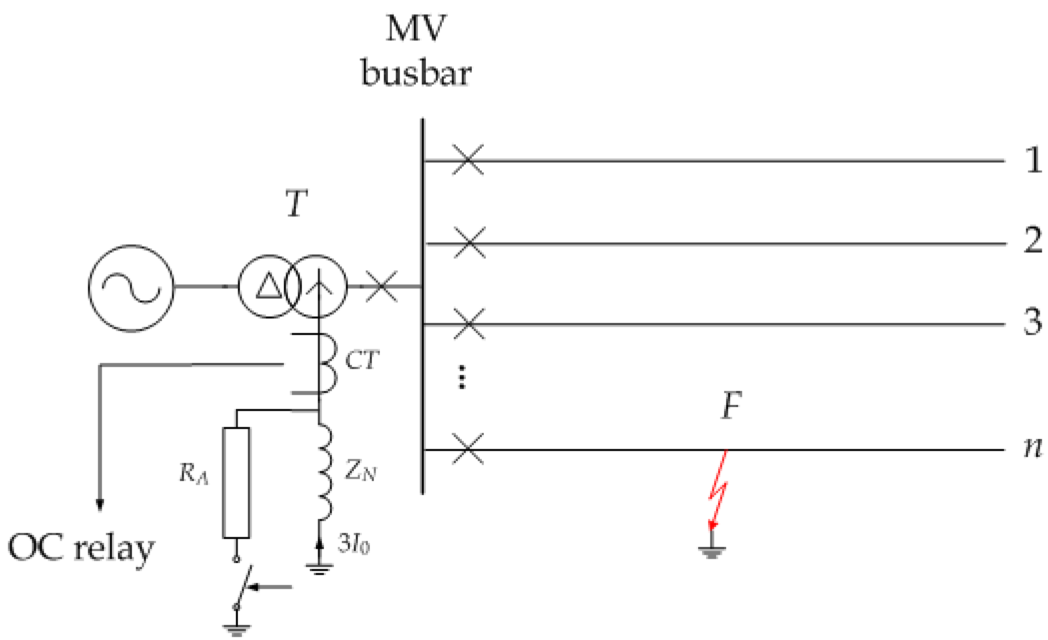
Intermittent ground fault: **A re-striking ground fault can create a high frequency oscillator (RLC circuit), independent of L and C values, causing high transient over-voltages.**



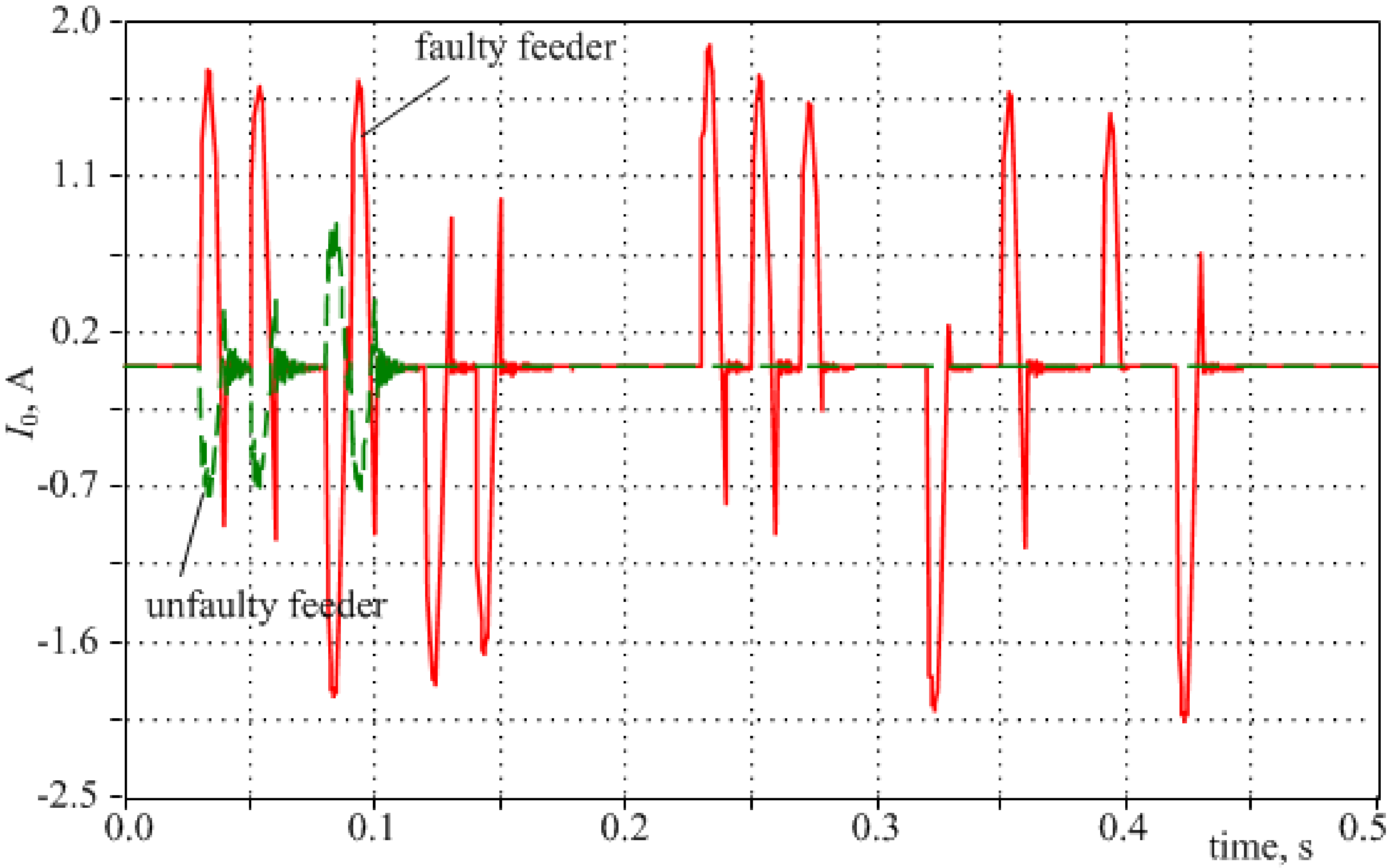
High-impedance grounding system

A substantial problem in ground-fault detection results from intermittent faults which occur because of aging wiring and connections. Intermittent faults are a growing problem in high-impedance grounding networks.

For increasing the protection selectivity an additional resistance /inductance in grounding circuit may be switched-on for short time.

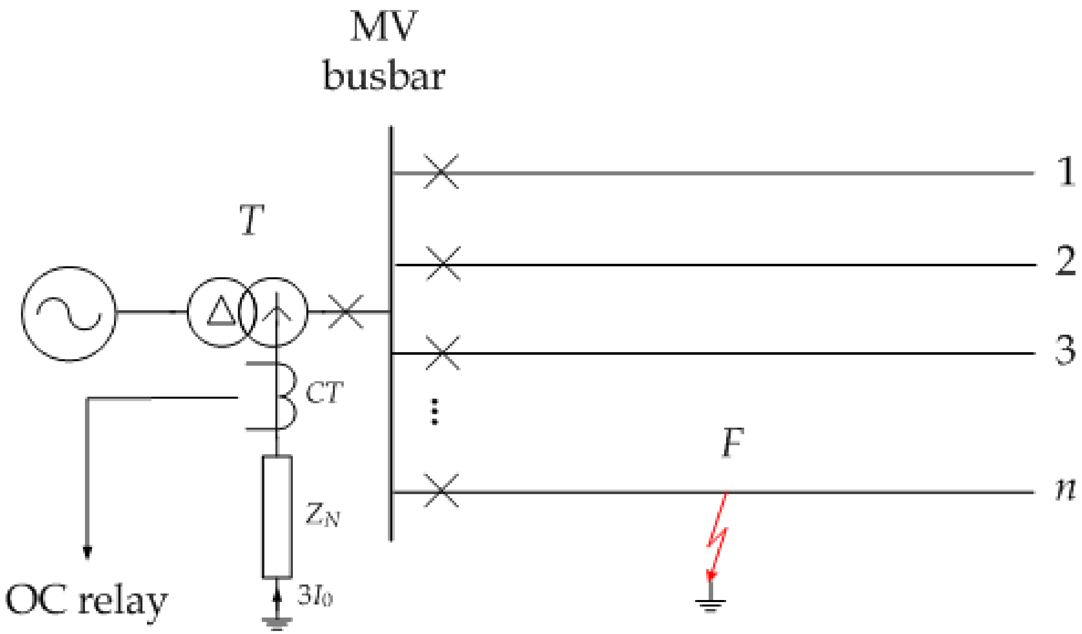


Intermittent fault



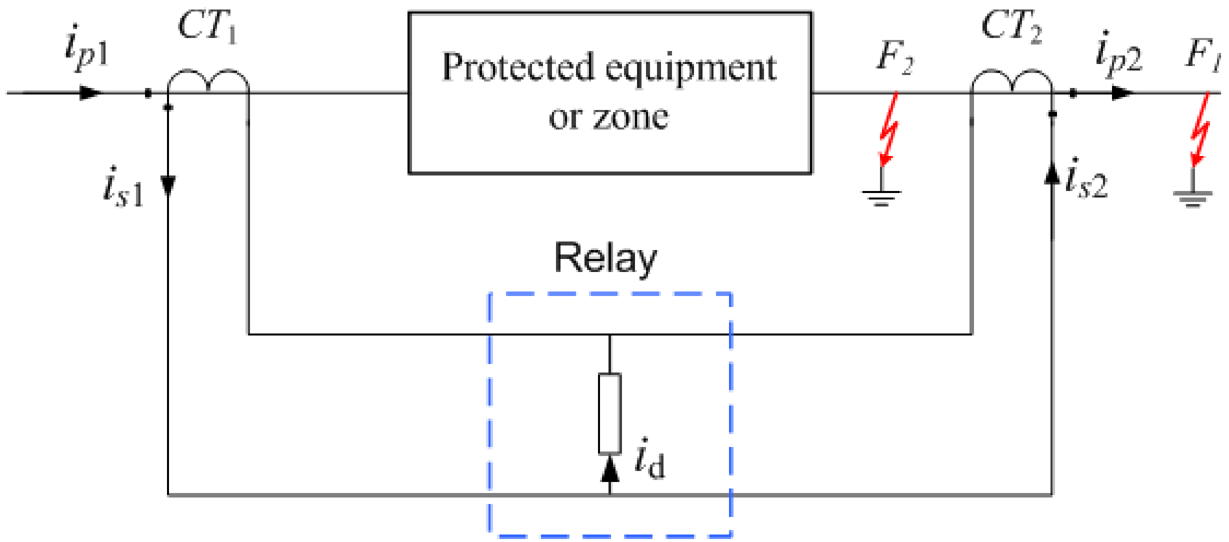
Low-impedance grounding system

The low-impedance-grounding limits line-to-ground fault currents to approximately 50 to 600 A primary. It is used to limit the fault current, yet permit selective protective relaying by magnitude differences in fault current by the power system impedances.



Differential protection principle

The best protection technique is that known as differential protection (Unit Protection). That is the unit protection.
For faults outside the zone the differential current is close to zero. During inside faults differential current is equall to the sum of both side currents.

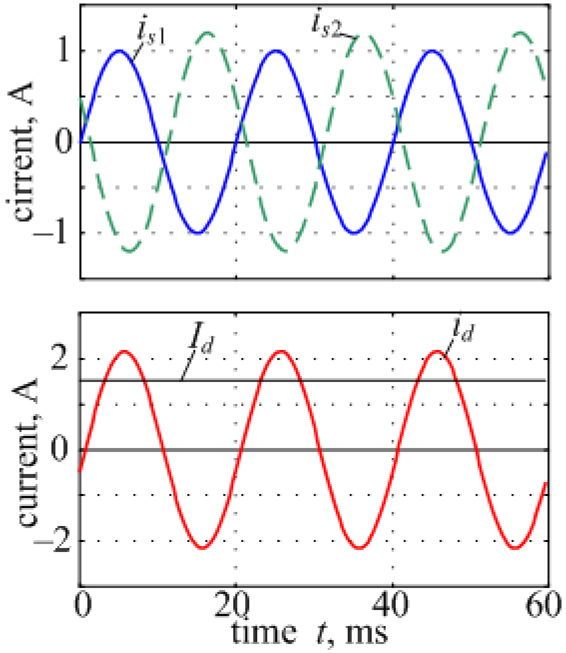


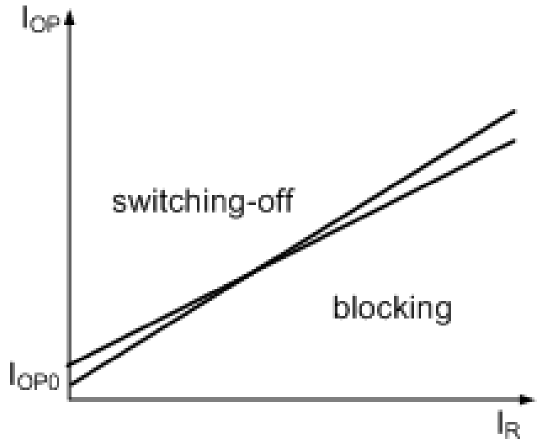
Differential current:

$$i_d = i_{s1} - i_{s2}$$

Line differential protection

Line differential protection needs transmission of fast end measurements to the local end.





$$I_{OP} = |I_{s1} - I_{s2}|$$ **- operating current**

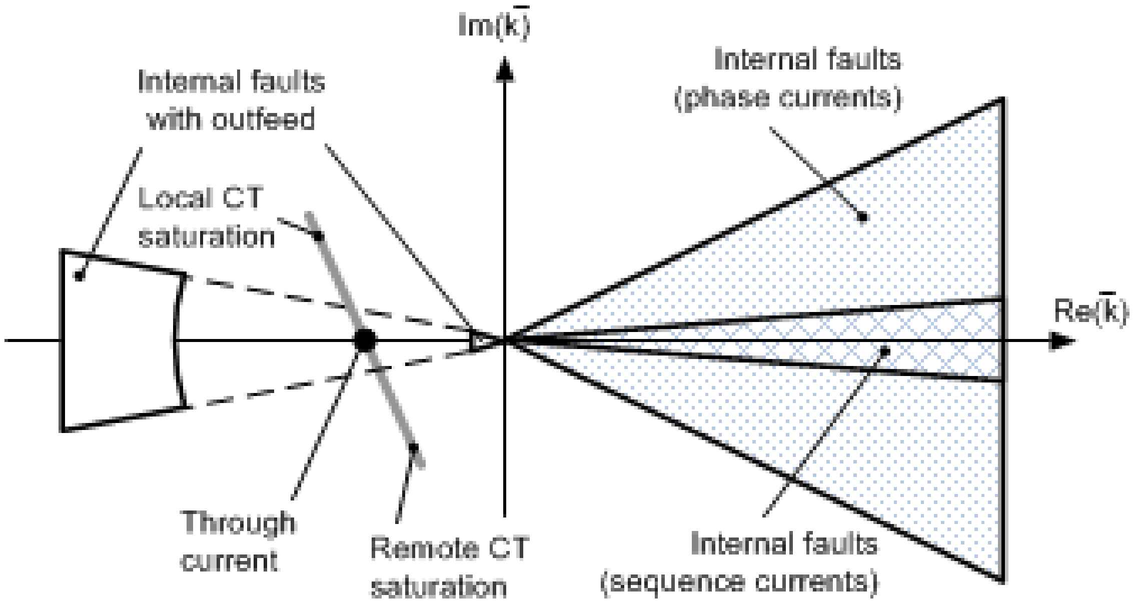
$$I_{RT} = |I_{s1} + I_{s2}|$$ **- restraint current**

$$\frac{I_{OP}}{I_{RT}} = const$$ **- percentage diff. protection**

Line differential protection

Alpha Plane increases sensitivity

$$\bar{k} = \frac{\bar{I}_R}{\bar{I}_L}$$



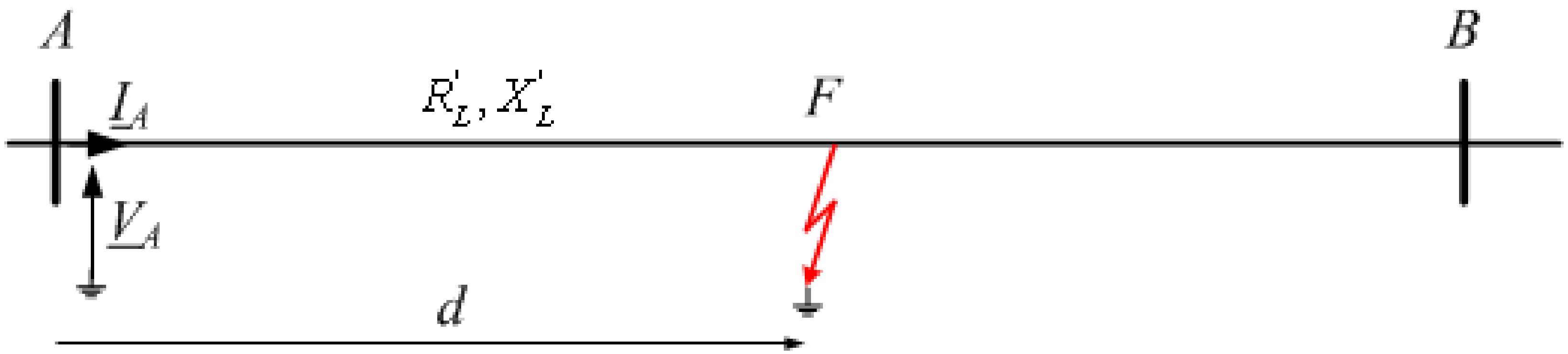
$\bar{\mathbf{I}}_R$ – remote current phasor
$\bar{\mathbf{I}}_L$ – local current phasor

Line distance protection

Ideal distance characteristics is related to the fault-loop complex impedance:

$$\underline{Z}_{FL} = \frac{\underline{V}_A}{\underline{I}_A} = R_{FL} + jX_{FL} \approx d\left(R_L^{'} + jX_L^{'}\right)$$

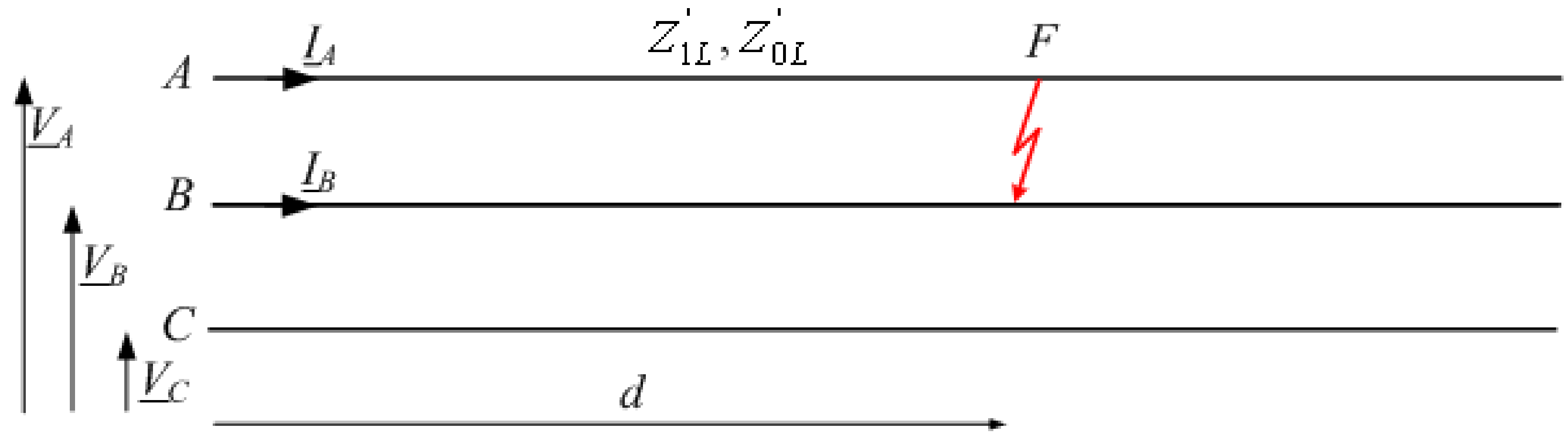
***R'$_L$*, *X'$_L$* - line parameters, Ω/km**



Distance protection: phase-to-phase fault

Ideal distance characteristics is related to the fault-loop complex impedance:

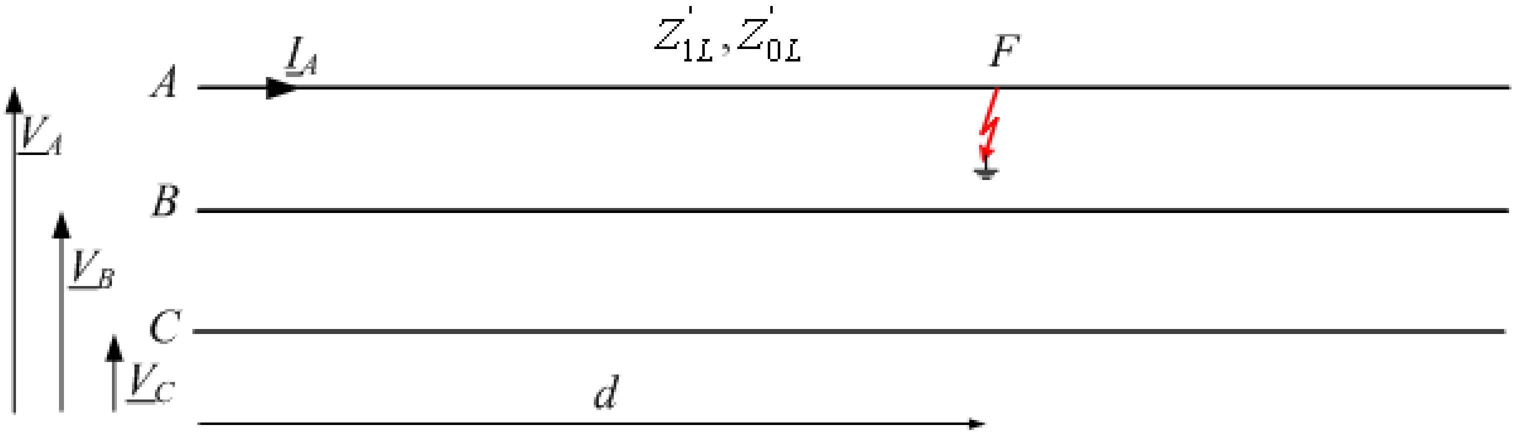
$$\underline{Z}_{FL} = \frac{\underline{V}_A - \underline{V}_B}{\underline{I}_A - \underline{I}_B} = \frac{\underline{V}_{AB}}{\underline{I}_A - \underline{I}_B} = d\underline{Z}_{1L}^{'}$$



Distance protection: phase-to-ground fault

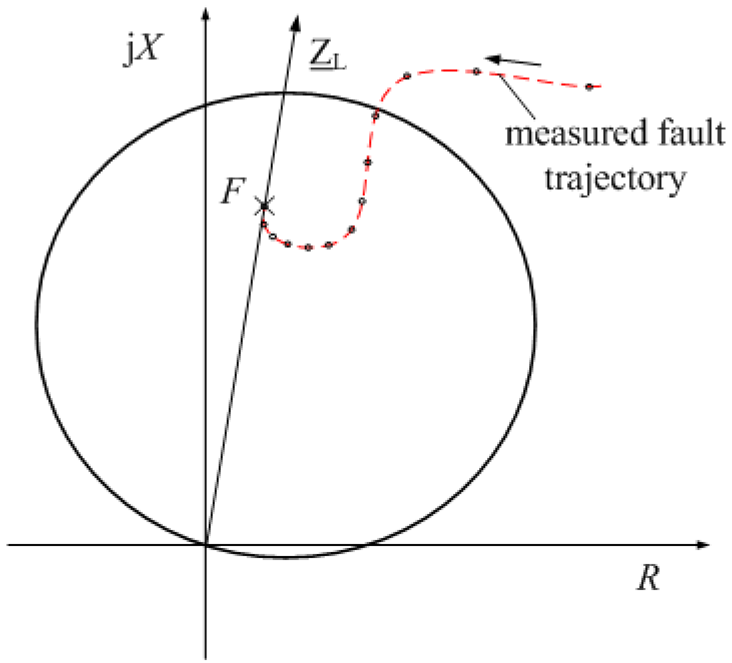
Distance to fault is calculated as follows:

$$\underline{Z}_{FL} = \frac{\underline{V}_A}{\underline{I}_A + \underline{I}_0 \dfrac{\underline{Z}'_{0L} - \underline{Z}'_{1L}}{\underline{Z}'_{1L}}} = \frac{\underline{V}_A}{\underline{I}_A - \underline{k}_0 \underline{I}_0} = d\underline{Z}'_{1L}$$



Distance protection: operation principle

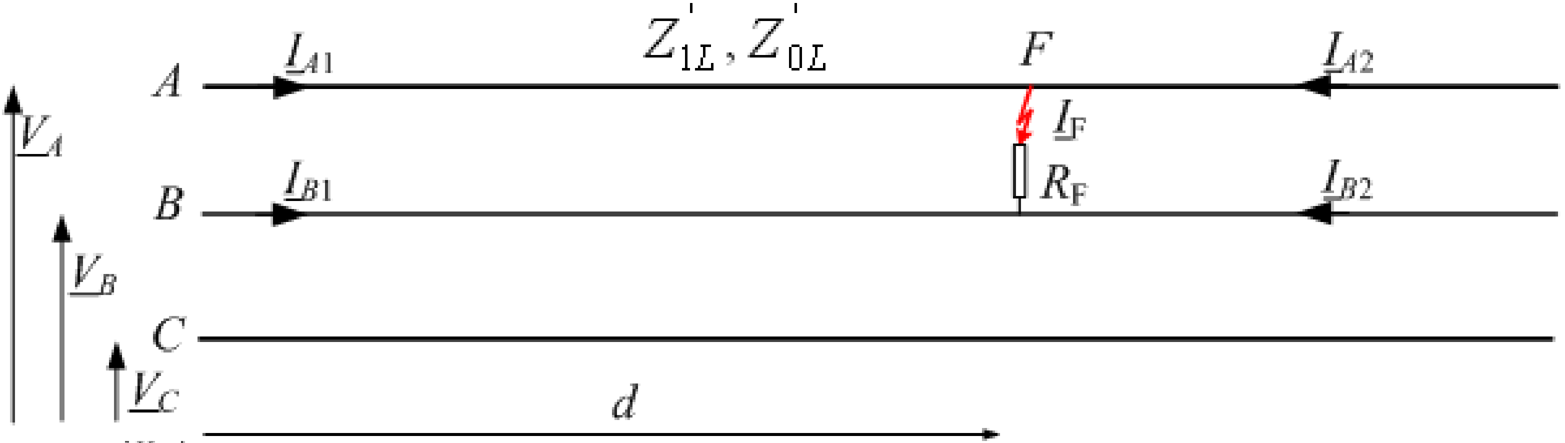
The basic principle of distance protection operation is as follows: whenever the measured impedance vector Z_{FL} falls inside a defined relay characteristic on *R*-*X* plane, the distance unit operates.
Distance relay characteristics originate from MHO characteristic.

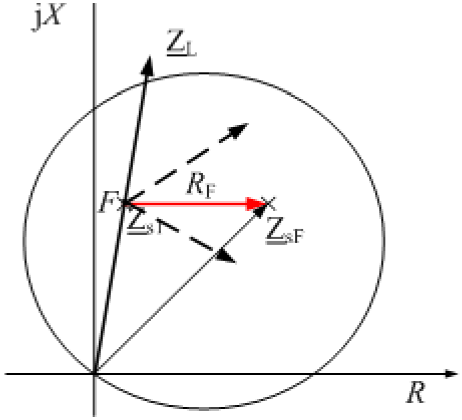


MHO distance characteristic
***F* – fault place,**
Z_L – line characteristic.

Distance protection – infeed (reactance) effect

Voltage drop on an unknown fault resistance R_F influences the correct distance to fault determination.



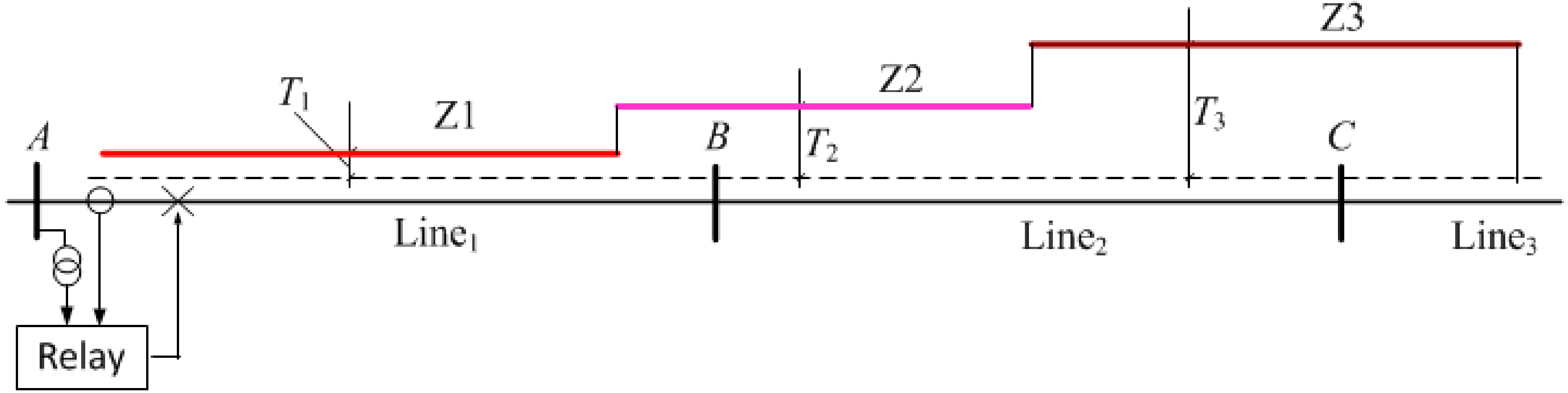


Fault resistance may result in overreach or underreach decision.

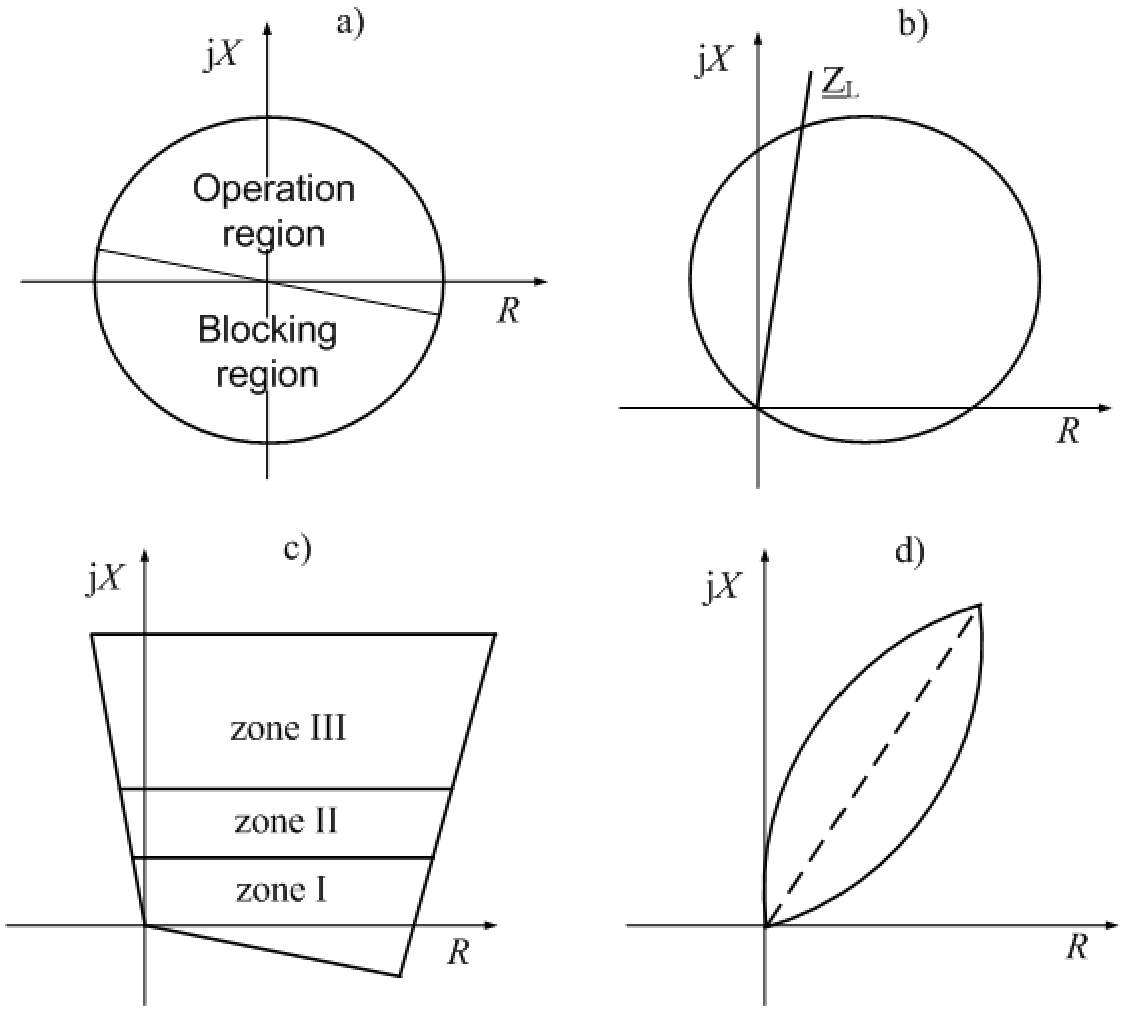
Distance protection zones

Traditionally three zones of protection have been used to protect a line section and provide backup for the remote section. Each of the three zones uses instantaneous operating distance relays.

Zone Z1 is set to 75 – 90 % of $Line_1$ impedance (instantaneous),
Zone Z2 – 100% of $Line_1$ + 50% of $Line_2$ (with delay T_2 = 0.2 – 0.3 s);
Zone Z3 – 100% ($Line_1$ + $Line_2$) + 25% of $Line_3$ (with delay T_3= 0.5 – 3 s).



Protection characteristics



a) **Circle characteristic**

b) **MHO characteristic**

c) **Quadrilateral characteristic**

d) **Lenticular characteristic**

Sources of errors

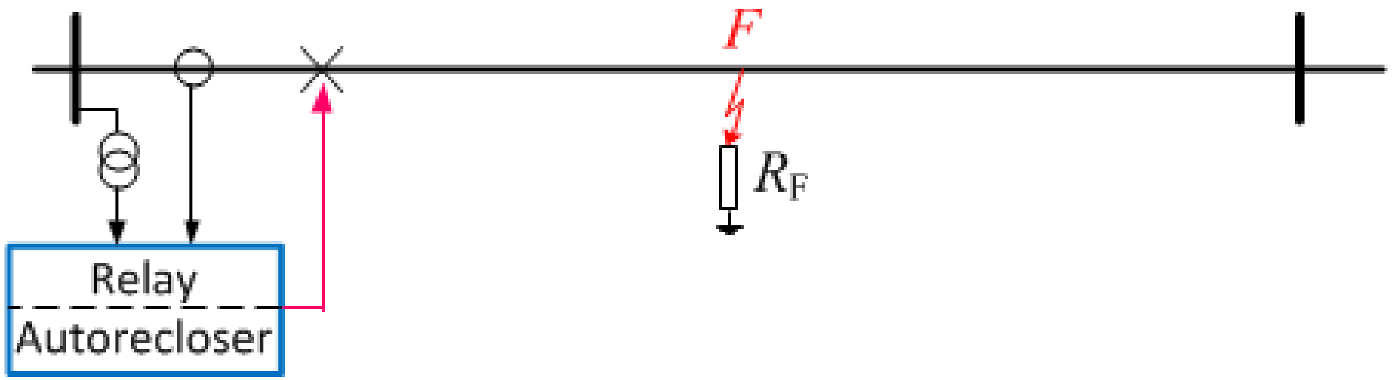
Distance elements should measure the positive-sequence impedance of the line section between the relay and fault. A number of the problems cause distance relay measuring errors, e.g.:

a) **Fault resistance and infeed effect;**
b) **Switch-onto-fault;**
c) **Mutual coupling in parallel lines;**
d) **Load and system unbalance;**
e) **Power swing due to electromechanical oscillations (in transmission lines);**
f) **Current transformer saturation;**
g) **CVT transients (in EHV lines);**
h) **Intercircuit faults;**
i) **…**

Automatic reclosing

Automatic reclosing (autoreclosing) is a control scheme for quickly reclosing breaker after clearing a temporary fault in order to restore the system to normal state as quickly as possible.

It is considered here that the fault is temporary and, once reclosed, the system will be restored to its normal condition. Adequate outage time must be allowed for the fault path to deionize if the scheme is to succeed.



Automatic reclosing

However, there is no way to guarantee that reclosing will be successfully, even though statistic show that a high percentage of faults are temporary and are successfully cleared by opening the line and then reclosing after a time delay for deionization of the arcing fault.

Autoreclosing

Reclosing to a permanent fault is called an unsuccessful reclosing.

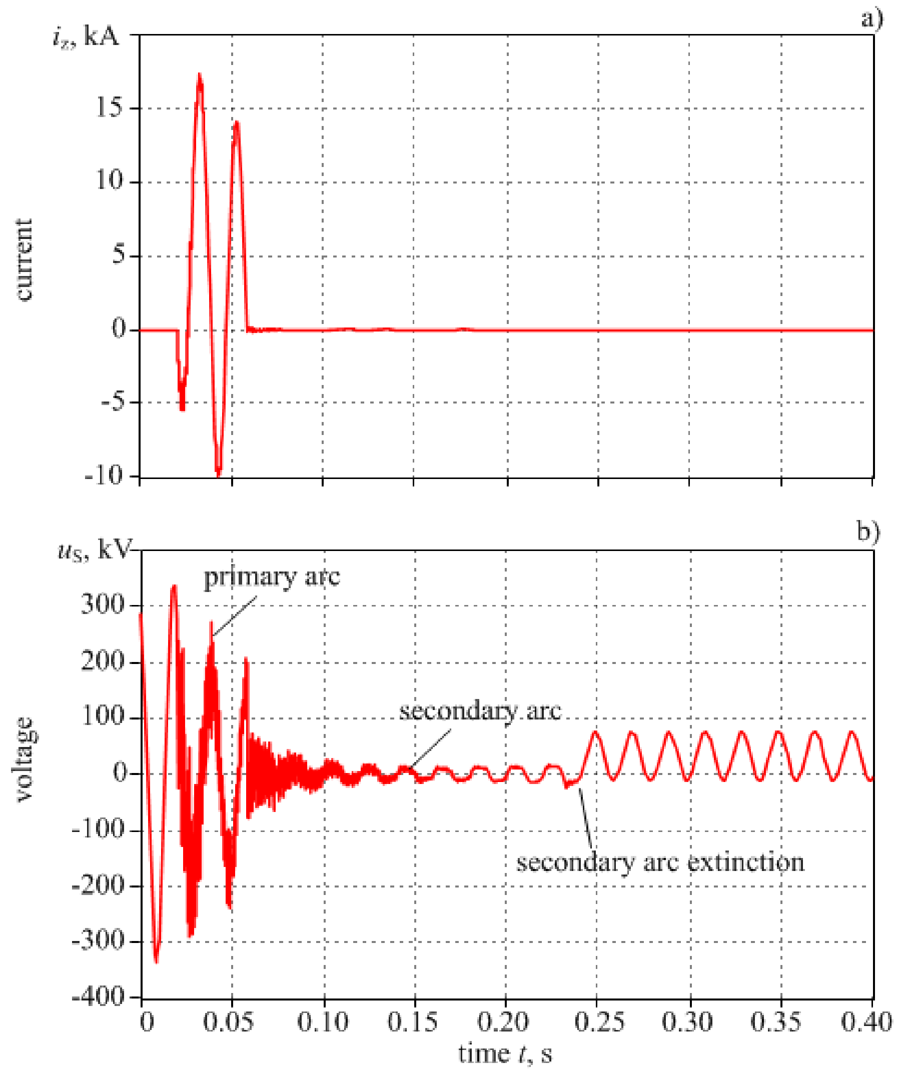
Important lines, especially tie lines that connect important generating stations, often require autoreclosing in order to maintain system stability for a given desired operating condition.

Autoreclosing at distribution networks is useful in order to limit the outage time of the consumers.

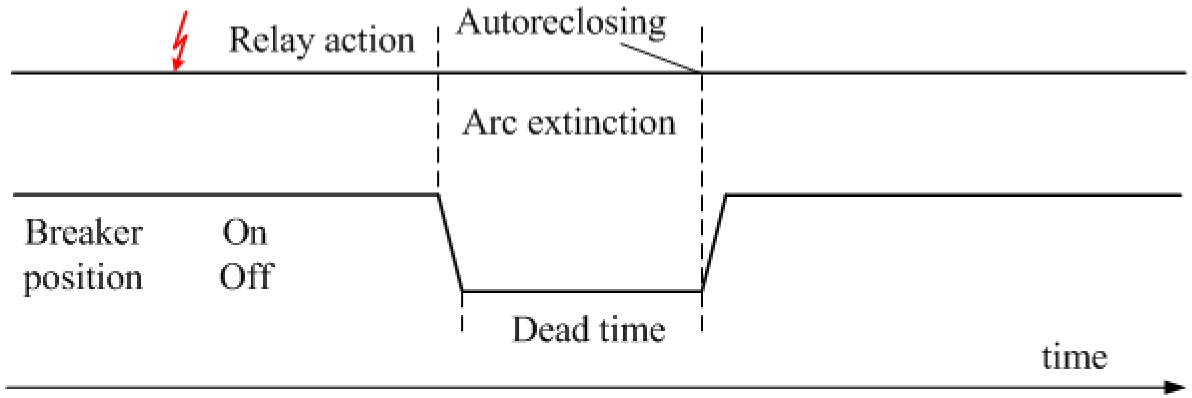
If reclosing is used in the network with distributed generation it may have to be dalayed to give the small generating units time to switch off prior to reclosing.

Autoreclosing scheme should detect a fault type to introduce reclosing only faulty phases.

Transient fault

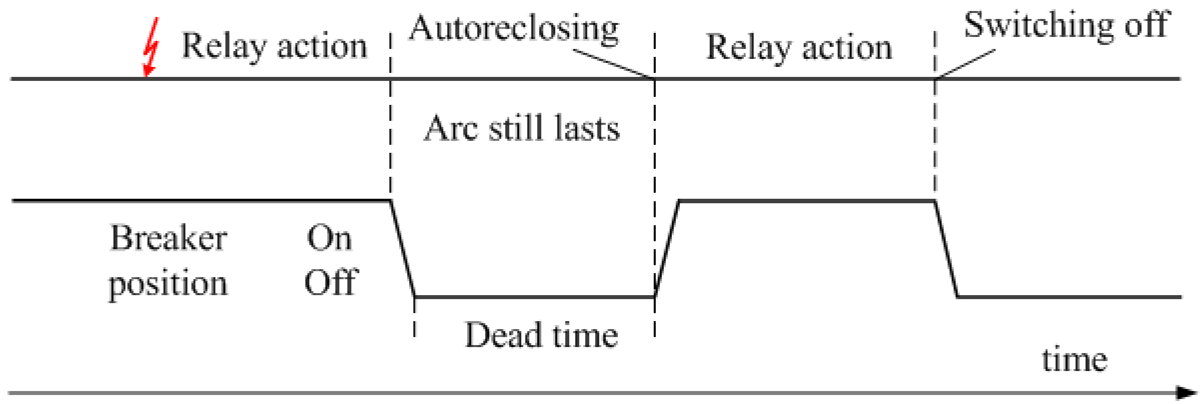


Autoreclosing cycles



successful reclosing

Single-shot Reclosing cycle



unsuccessful reclosing

Transformer Protection

Transformers are a critical and expensive component of the power system.

Transformer Protection

Due to the long lead time for repair of and replacement of transformers, a major goal of transformer protection is limiting the damage to a faulted transformer.

Introduction

Transformer failures are expensive and also may be dengerous for personnel. The cost of energy not delivered because of transformer unavailability and additional costs may be very high.
Transformer protection scheme should disconnect the transformer before extensive damage occurs in the transformer and the system.
Main transformer abnormal conditions are as follows:

- **internal faults (interturn, phase-to-phase, phase-to-ground),**
- **overload,**
- **overexcitation causing saturation the transformer core,**
- **sudden gas pressure,**
- **tap changer failures (if a tap changing mechanism is installed) and others.**

Classification of protection means

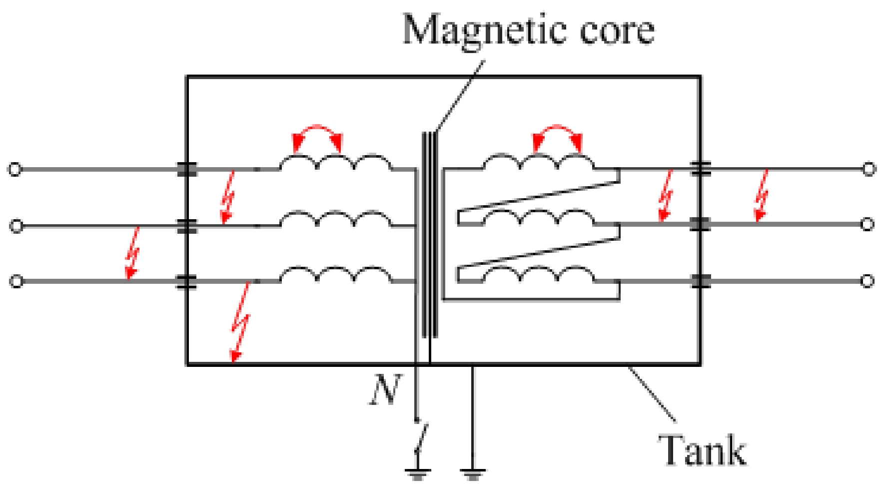
The methods of protection of a power transformer depend on its kVA rating and its importance for the power system operation. It is obvious that large units would be protected by relays that utilize more reliable operating principles with more redundancy in back-up relays. Main types of transformer protection are as follows:

1. **Internal fault protection (usually differential current protection);**
2. **Overcurrent protection;**
3. **Ground fault protection;**
4. **Overexcitation (overfluxing) (V/Hz) protection;**
5. **Overheating (thermal) protection;**
6. **Overpressure.**

Transformer abnormal conditions

Main transformer abnormal conditions are as follows:

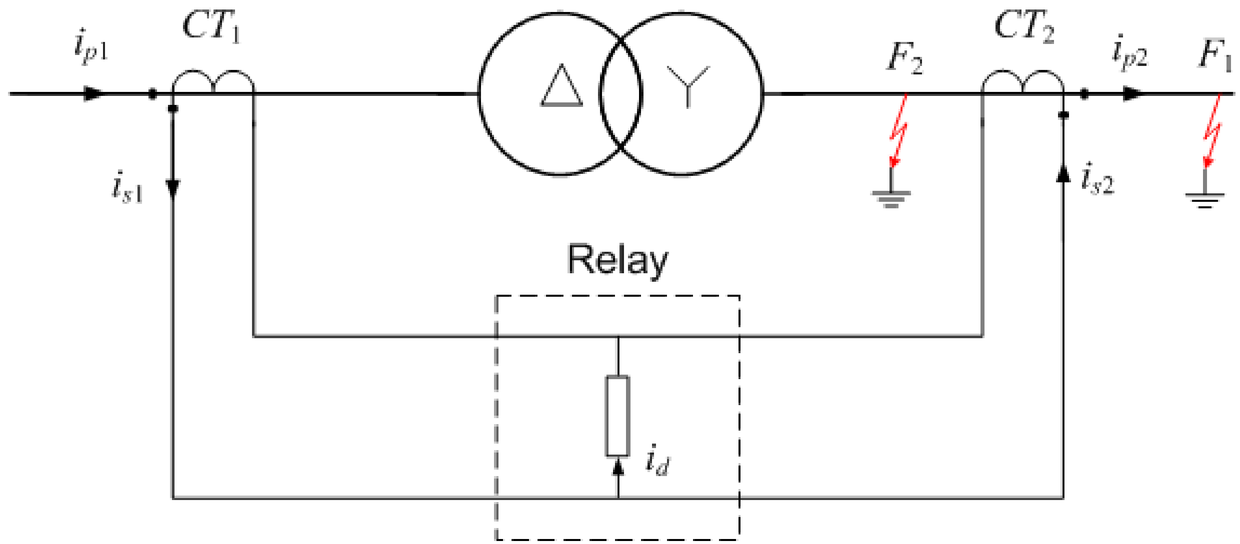
- **internal faults (interturn, phase-to-phase, phase-to-ground),**
- **overload,**
- **overexcitation causing saturation the transformer core,**
- **sudden gas pressure,**
- **tap changer failures (if a tap changing mechanism is installed).**



Transformer internal faults

Transformer differential protection

Main idea:

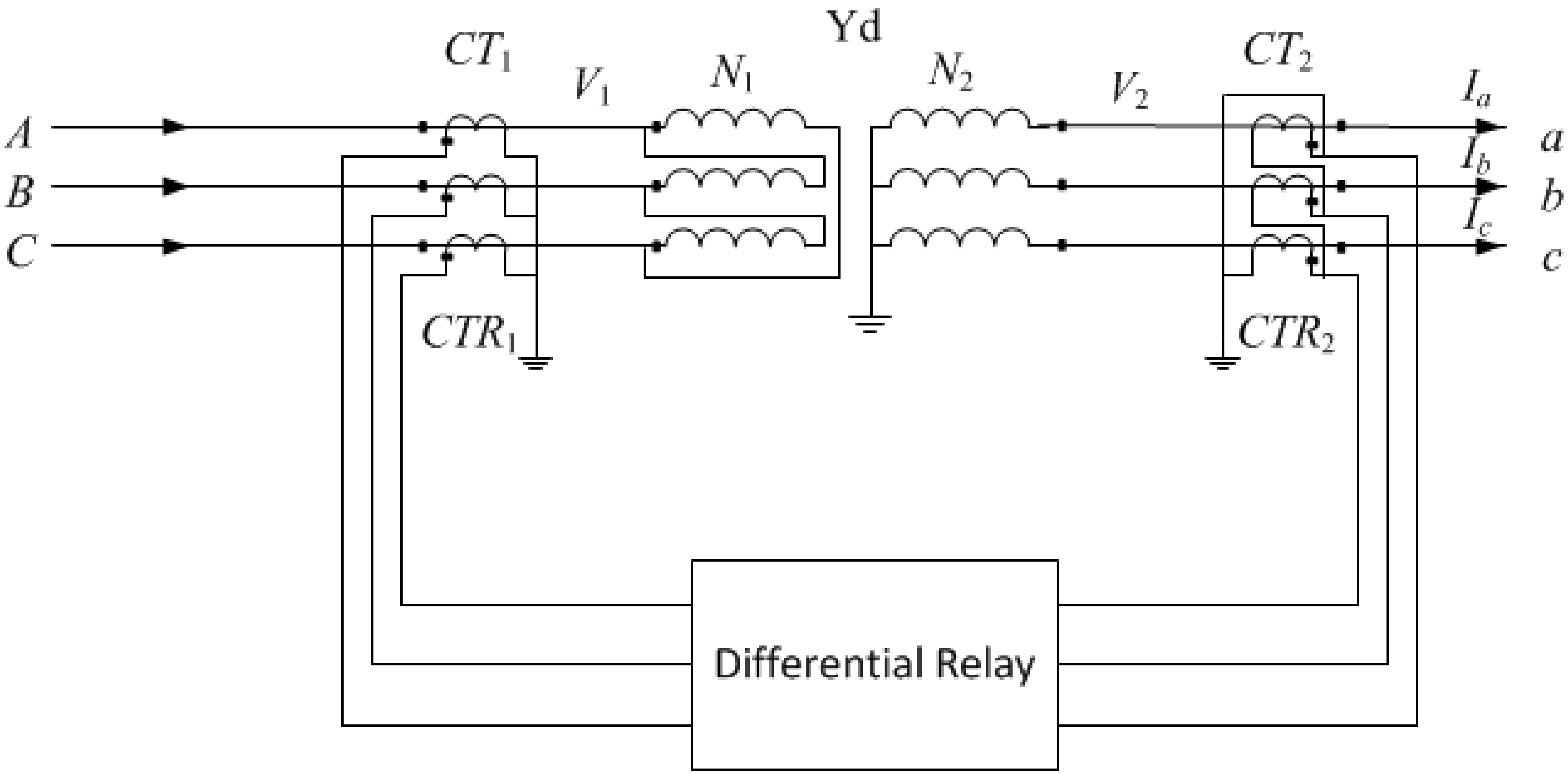


$$I_{OP} = | I_{s1} - I_{s2} | \rightarrow | I_{W1} - I_{W2} |$$ **- operating current**

$$I_{RT} = | I_{s1} + I_{s2} | \rightarrow | I_{W1} + I_{W2} |$$ **- restraint current**

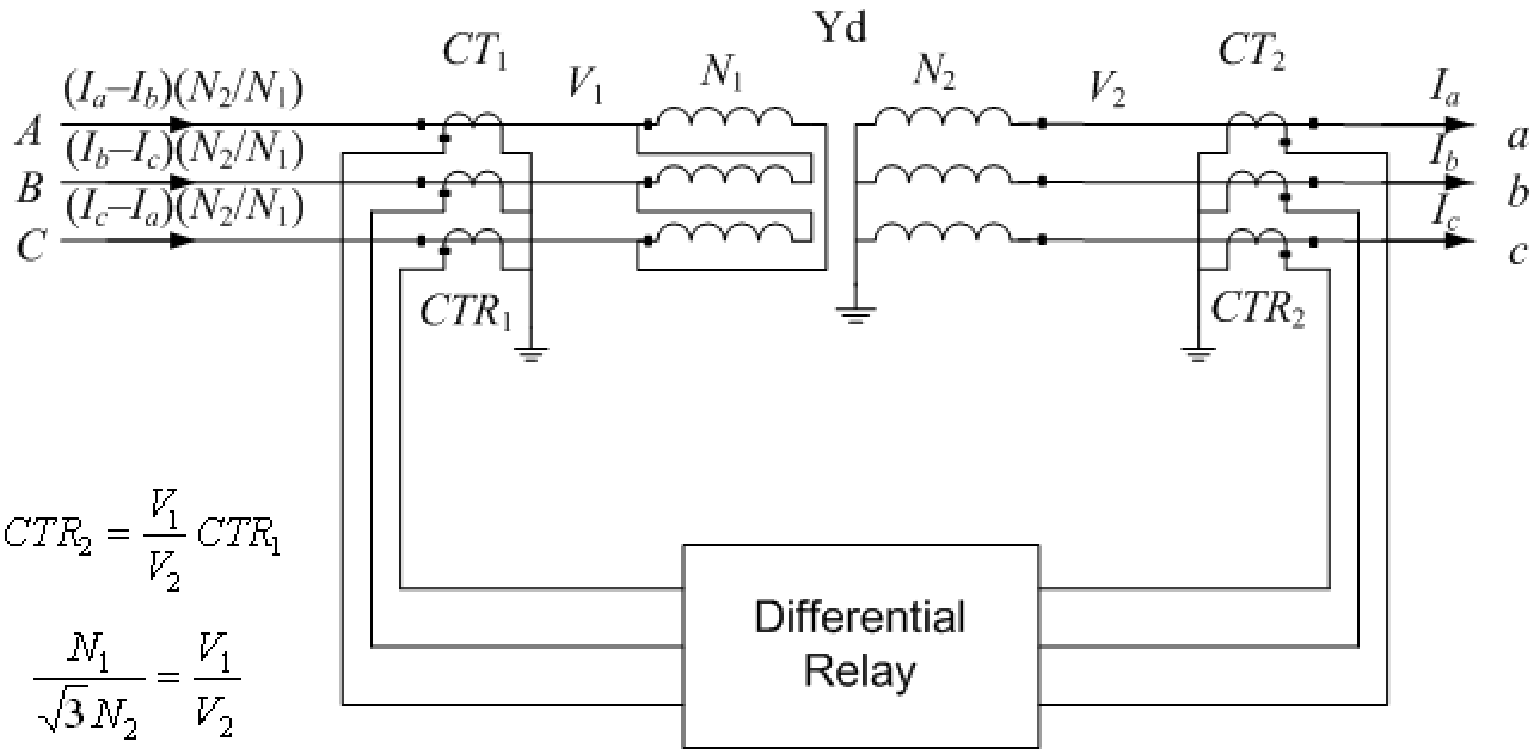
I_{W1}, I_{W2} **- compensated phasor currents measured by the relay.**

Windings and CTs connection



CTR_1, CTR_2 **- CTs rated current.**

Windings and CTs connection

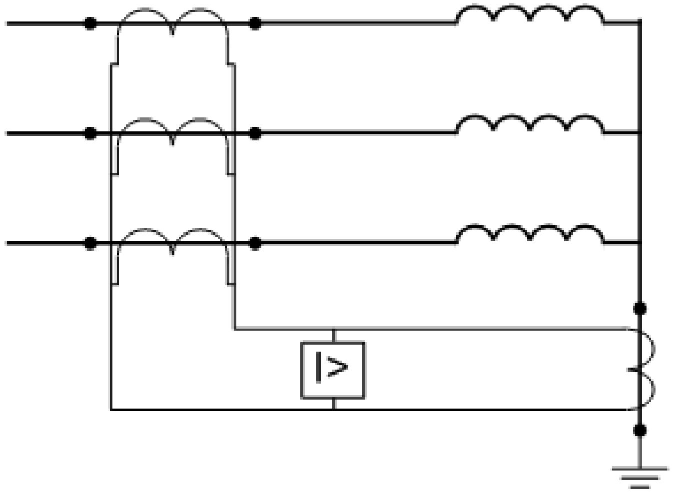


$$CTR_2 = \frac{V_1}{V_2} CTR_1$$

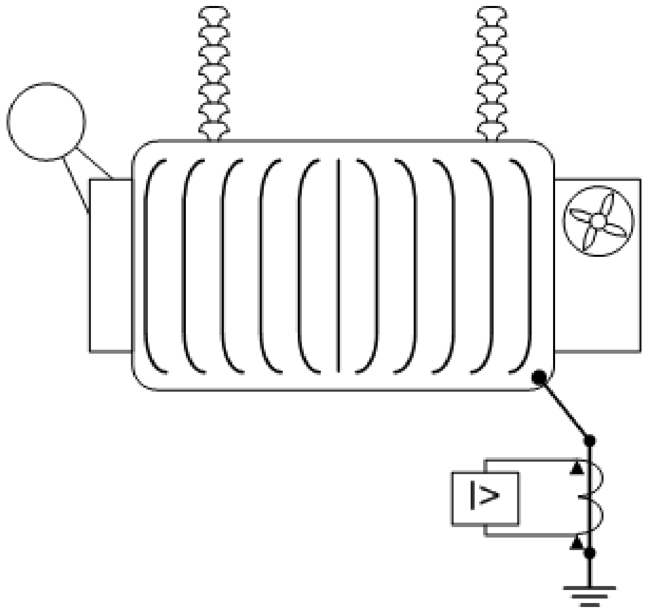
$$\frac{N_1}{\sqrt{3} N_2} = \frac{V_1}{V_2}$$

CTR_1, CTR_2 **- CTs rated current.**

Earth fault protection

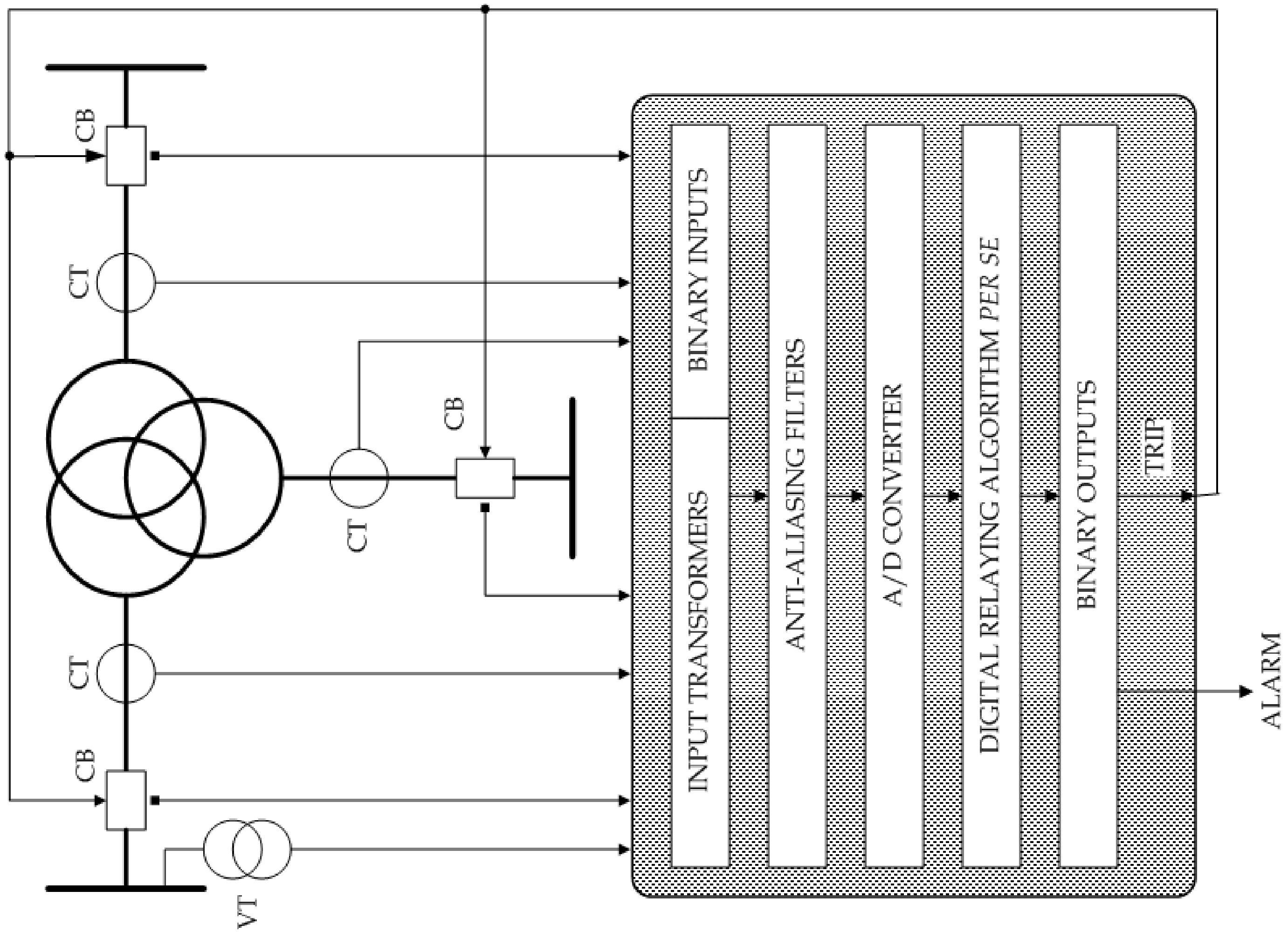


Restricted earth fault protection



Tank earth fault protection

Transformer differential protection



Transformer differential protection

Operating conditions for power transformer relays, do not make differential protection task easy. A number of factors contribute to this. The most critical include:

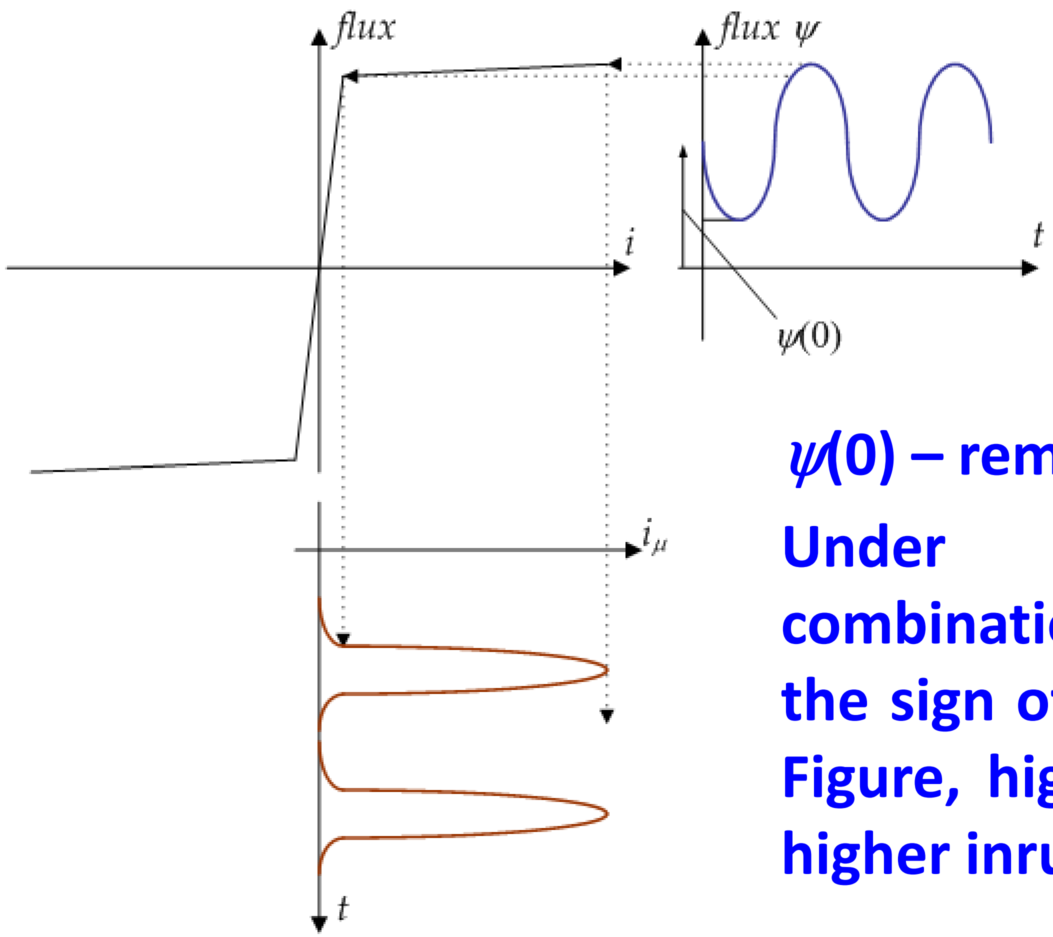
- **saturation of Current Transformers (CTs) during both internal and external faults;**
- **not perfect match between the ratios of the CTs and the protected transformer, especially if an on-load tap changer is installed;**
- **magnetizing inrush currents and stationary overexcitation of the transformer core;**
- **extremely wide range of internal fault currents.**

Magnetizing Inrush — A Brief Analysis

Magnetizing inrush current in transformers results from any abrupt change of the magnetizing voltage. Although usually considered a result of energizing a transformer, the magnetizing inrush may be also caused by:

- **occurrence of an external fault;**
- **voltage recovery after clearing an external fault;**
- **change of the character of a fault (for example when a phase-to-ground fault evolves into a phase-to-phase-to-ground fault);**
- **out-of-phase synchronizing of a connected generator.**

Magnetizing Inrush — A Brief Analysis

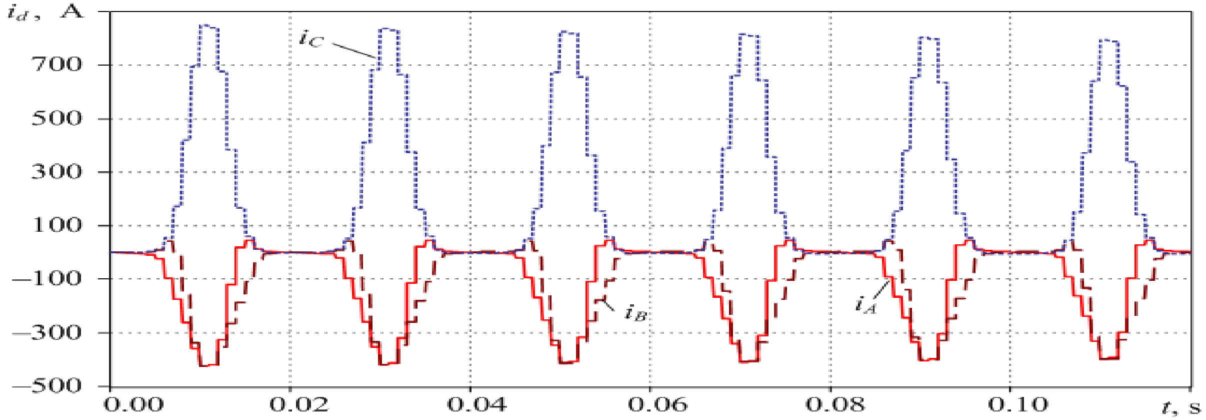


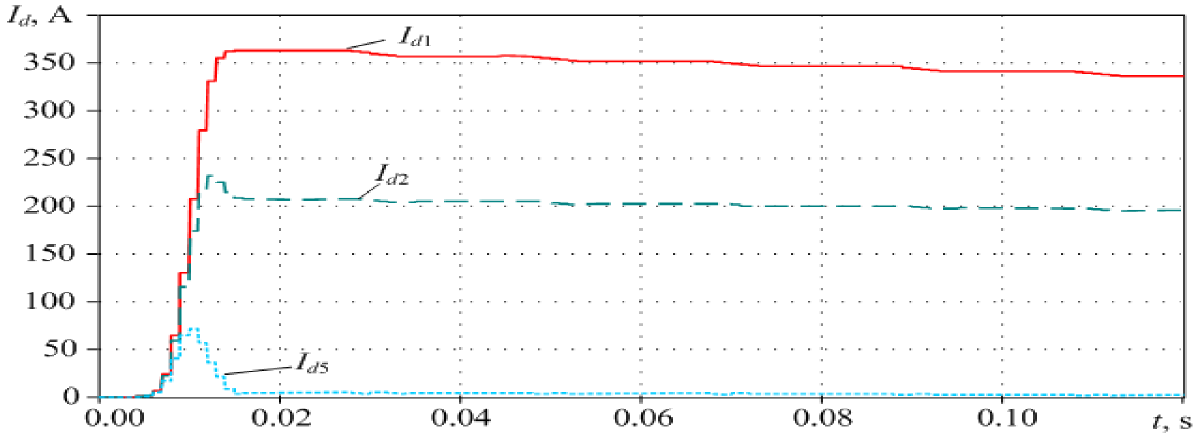
$$\psi(t) = \int v_m(t)\mathrm{d}t + \psi(0)$$

$\psi(0)$ – remanent flux.

Under the most unfavorable combination of the voltage phase and the sign of the remanent flux shown in Figure, higher remanent flux results in higher inrush currents.

Differential protection – magnetizing inrush





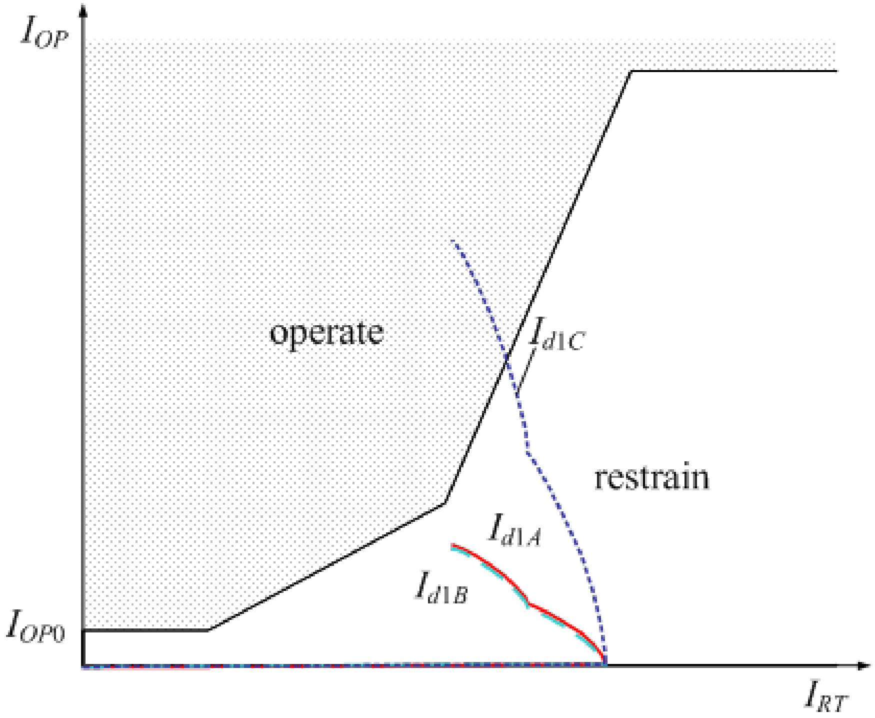
Harmonic restraint:

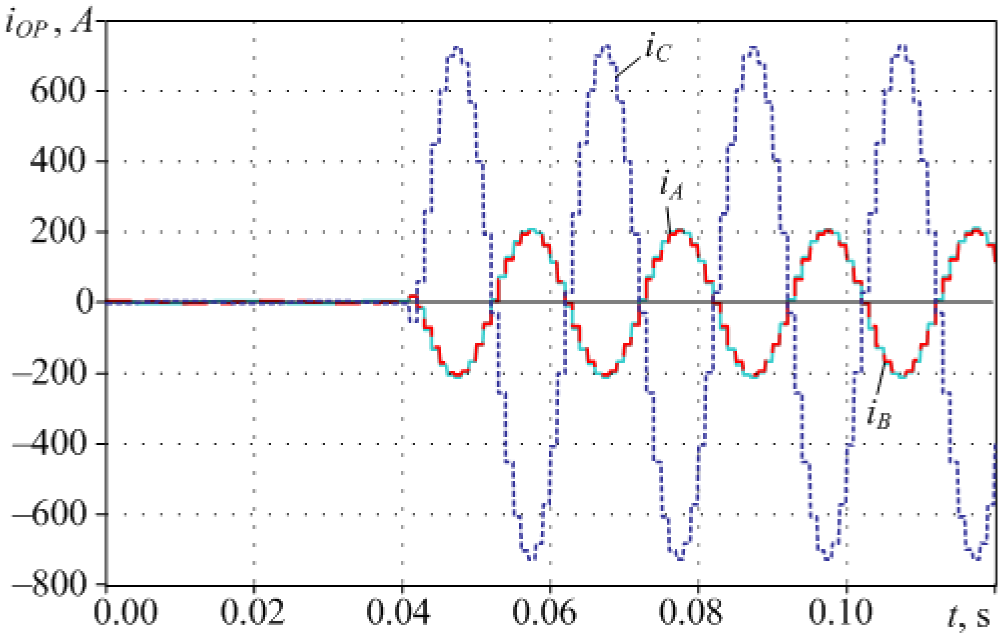
Blocking if:

$$Id_2 > k_2\ Id_1$$

with: $k_2 \approx 0.2$

Differential protection

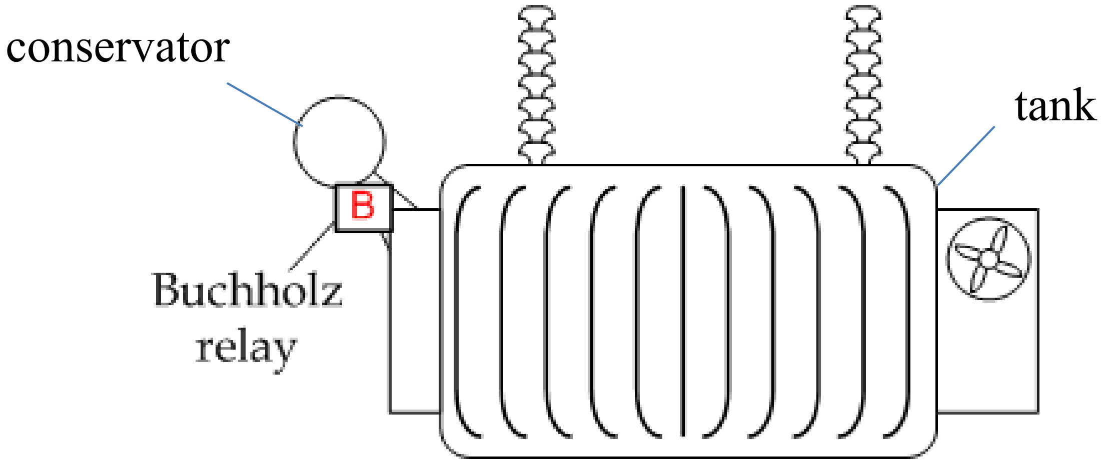




Typical bias characteristic

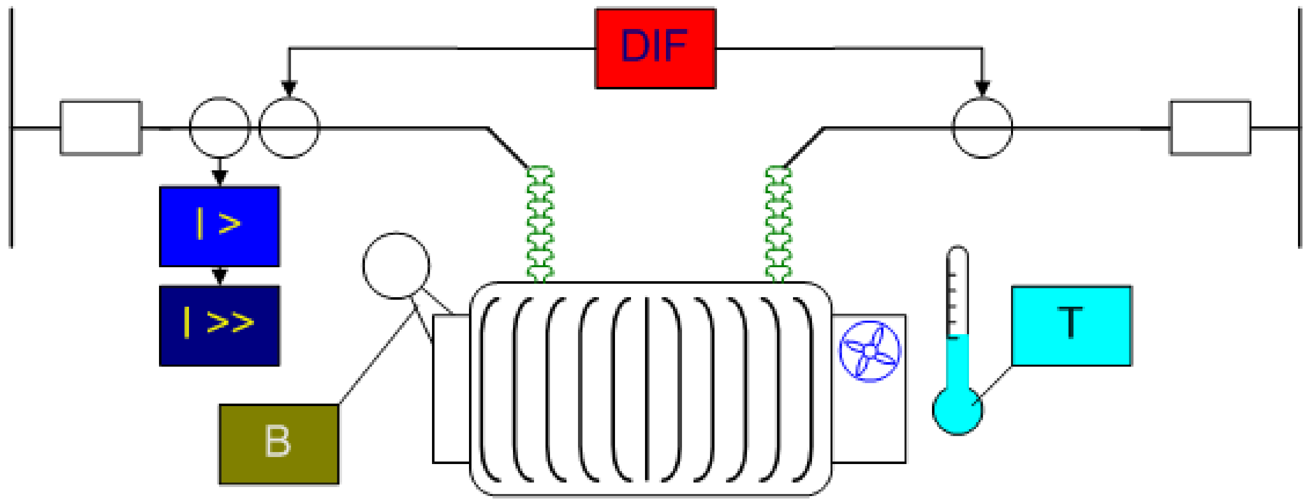
Example: internal fault – 5% inter-turn fault at winding of phase C

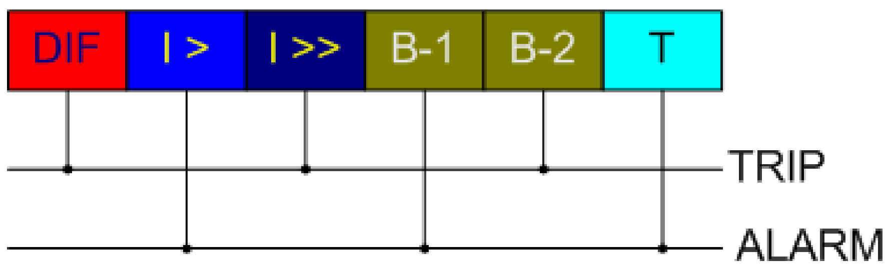
Buchholz protection



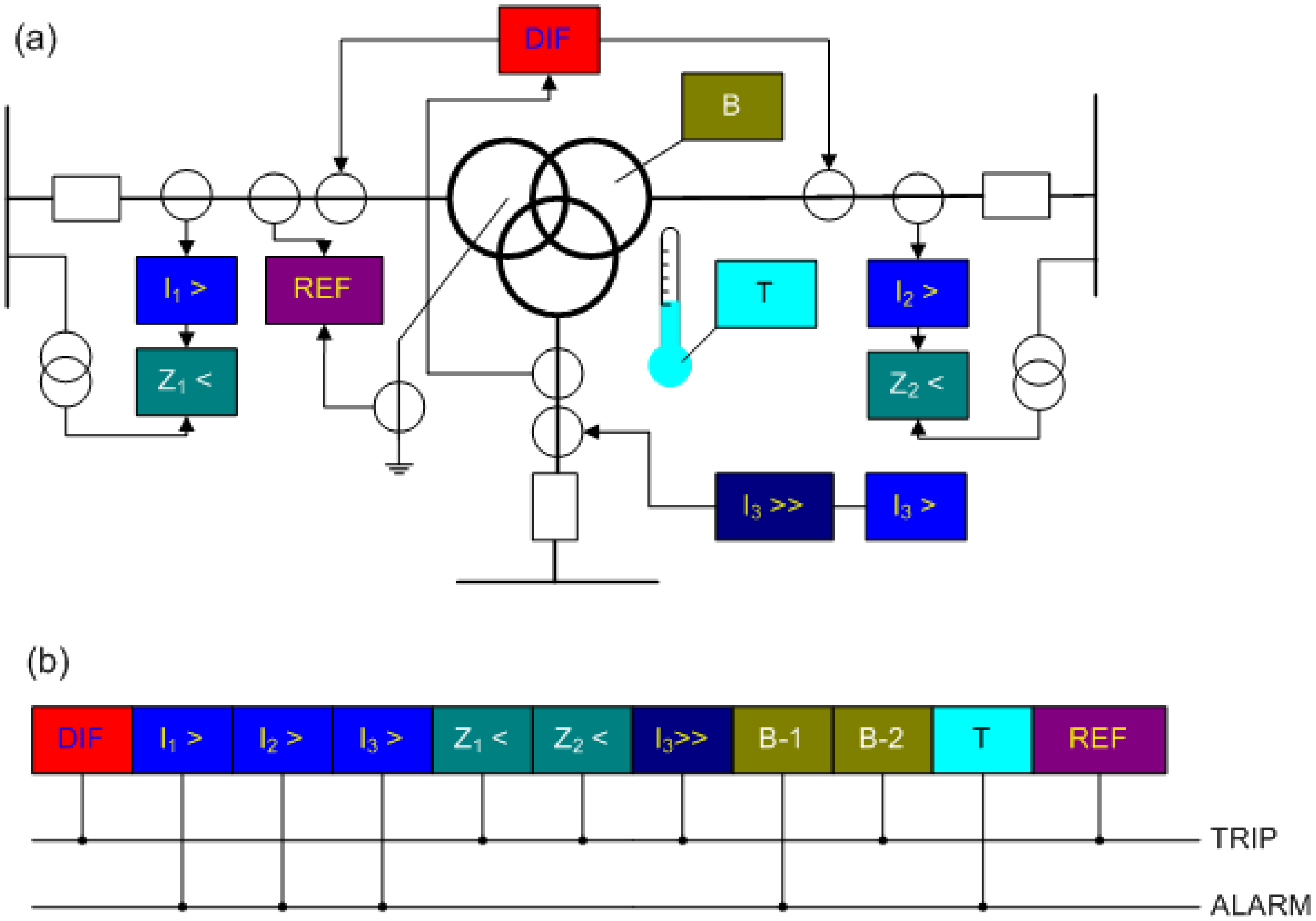
Buchholz relay is used to protect against faults involving severe arcing causes a very rapid release of large volumes of gas and oil vapour.
The Buchholz relay is contained in a cast housing which is connected in the pipe to the conservator.

Typical scheme for medium size transformer





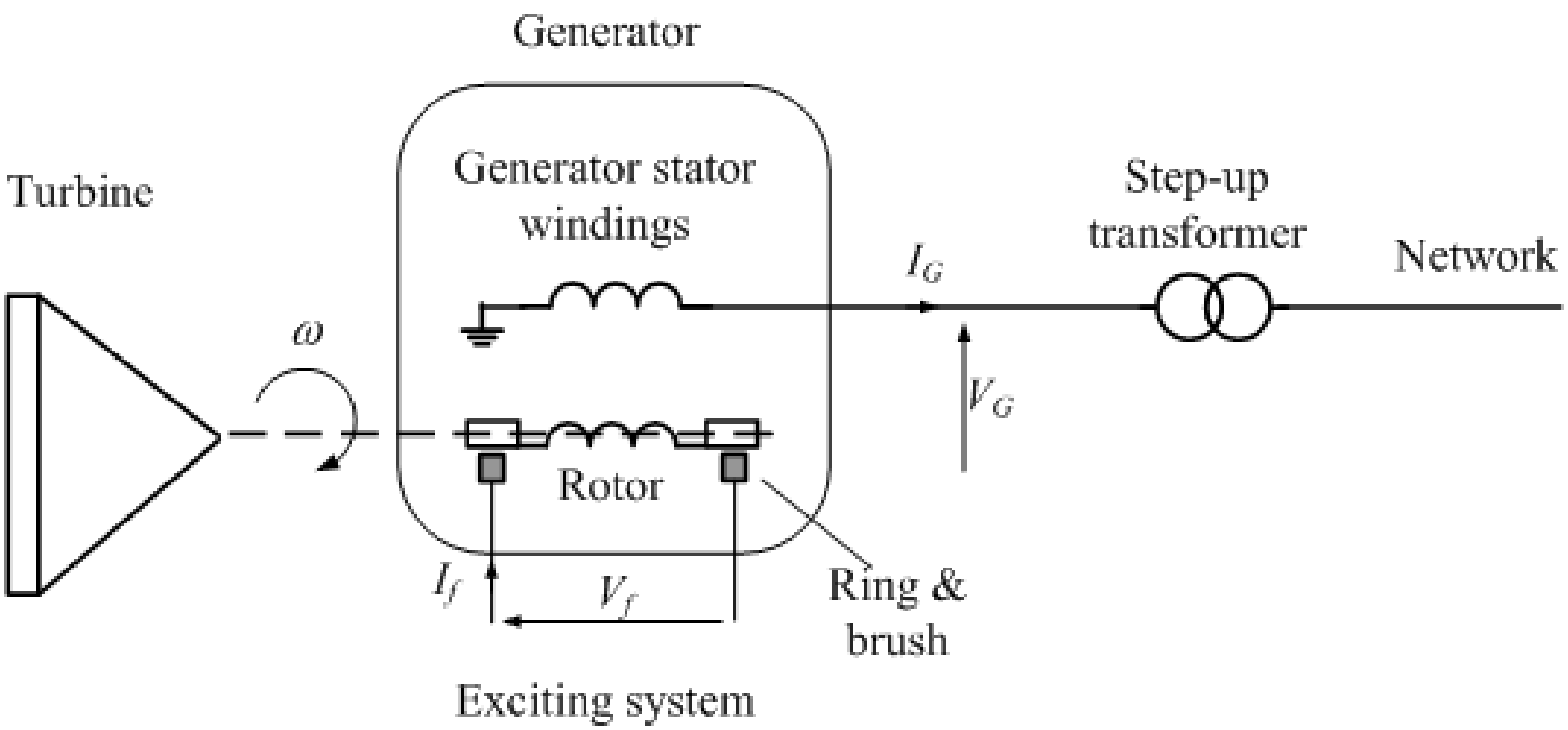
Typical scheme for large power transformer



Introduction

- Generation is the core of an electric power system. Generators based on steam, gas, water or wind turbines and reciprocating combustion engines are all in use. Majority of used generators are synchronous generators. In the wind farms there are applied also induction (asynchronous) generators.
- Power plants represent approximately half of the investment in an electric power system and that is why proper (secure) generators protection is very important task.

Introduction



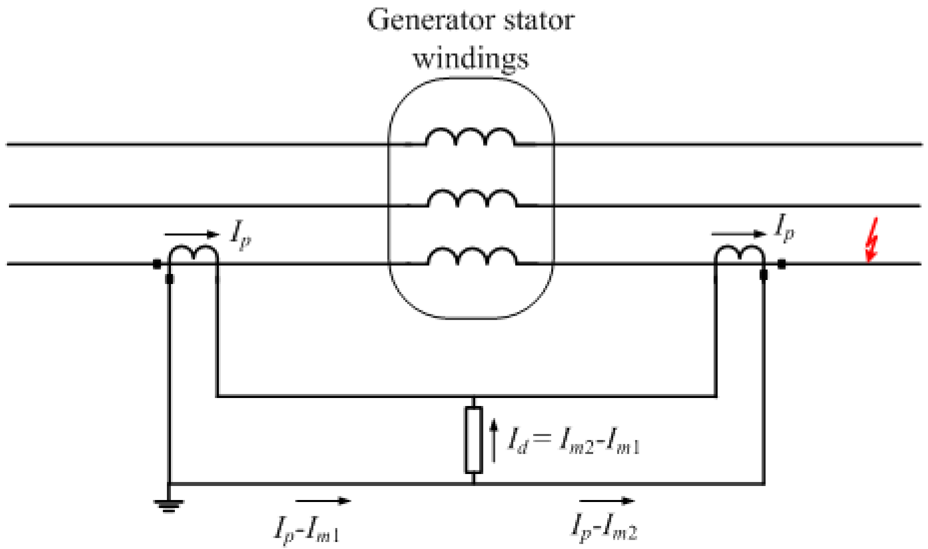
Generator circuits

Introduction

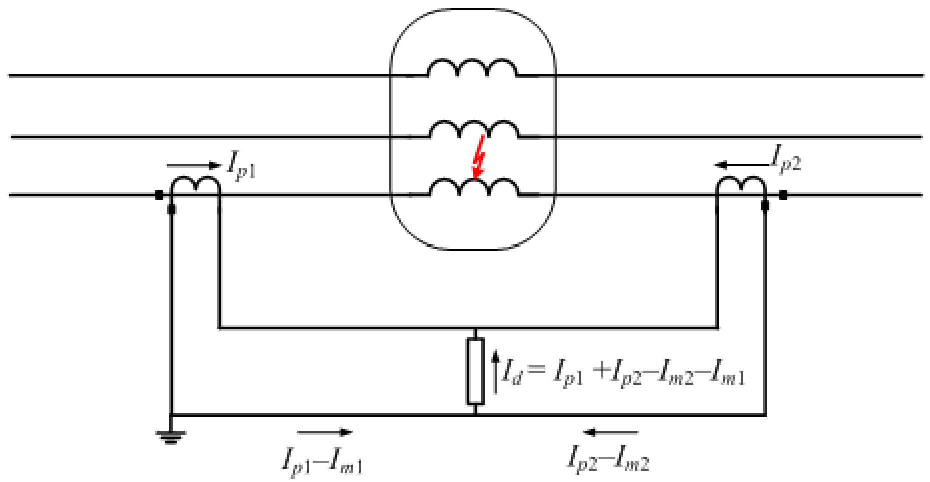
More important abnormal conditions that must be dealt with are:

1. **Winding Faults:**
   a) **Stator – phase and ground**
   b) **Rotor**
2. **Overload**
3. **Overspeed**
4. **Abnormal voltage and frequency**
5. **Underexcitation and start-up**
6. **Loss-of field**
7. **Current unbalance**

Stator windings Differential Protection

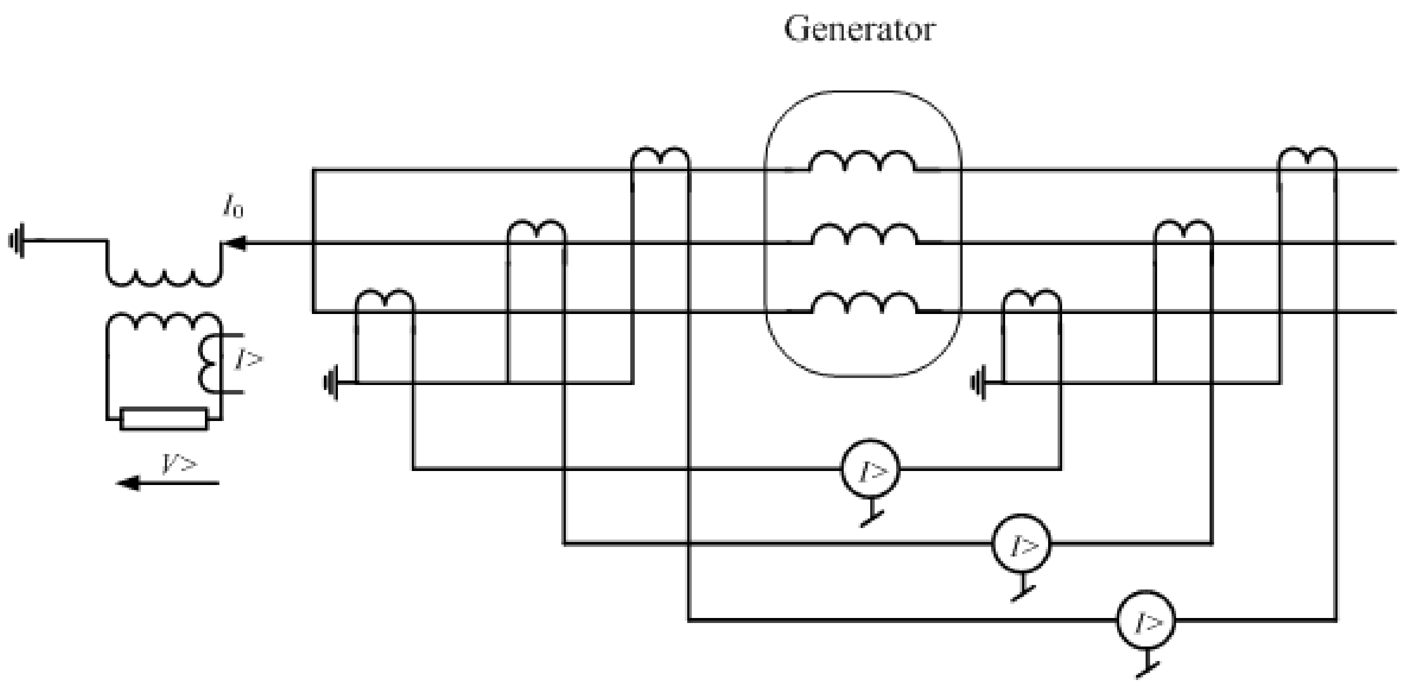


a) Fault outside zone



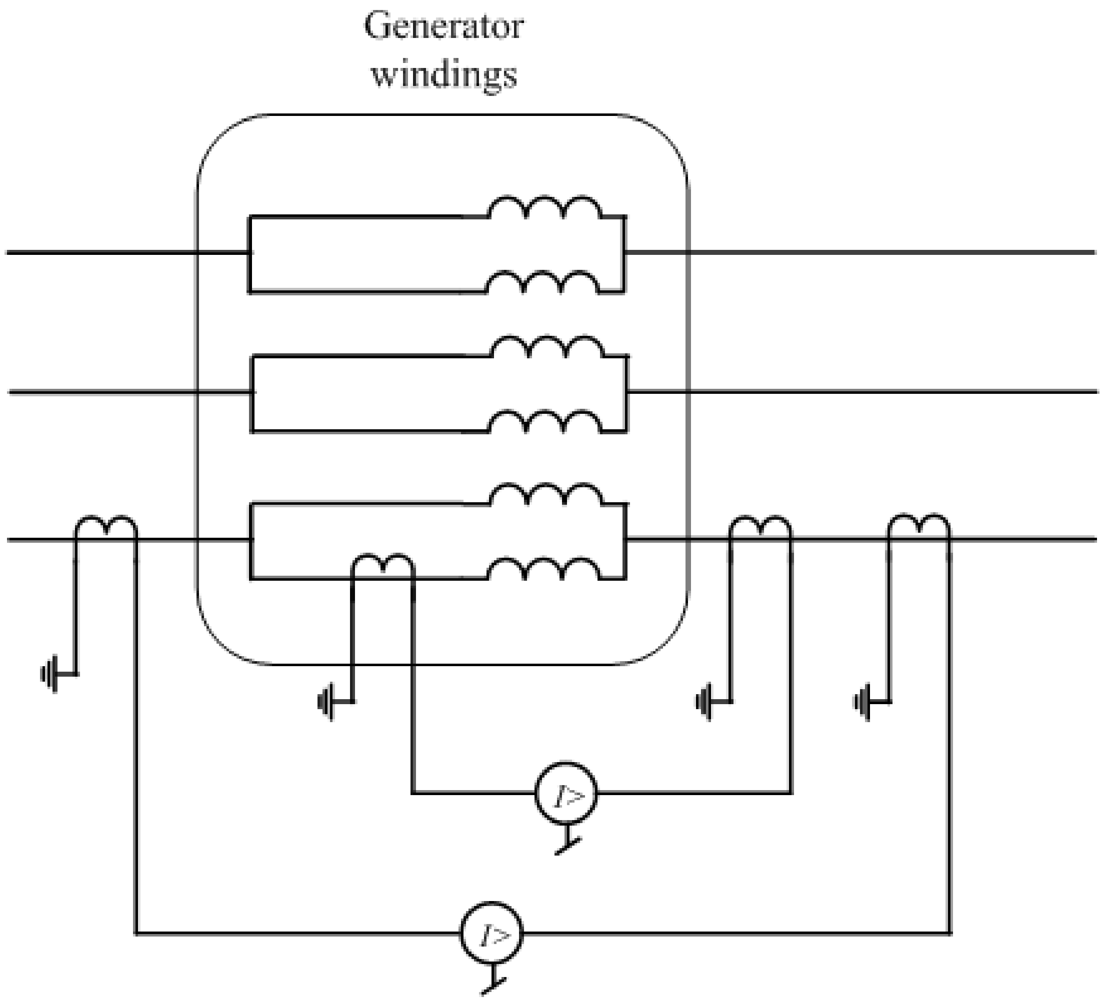
b) Fault in zone

Stator Fault Protection



Protection scheme for high-resistance-grounded generator with differential protection

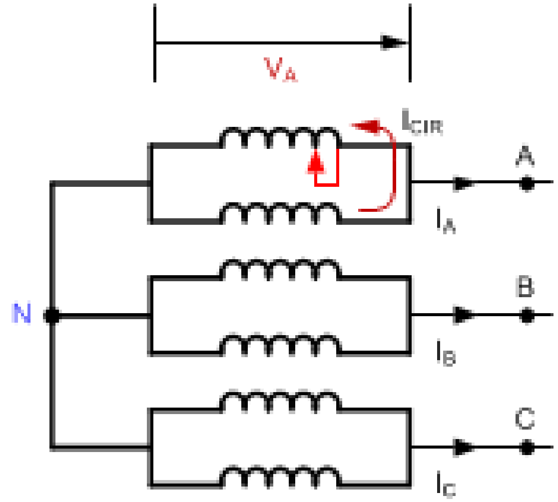
Stator Fault Protection



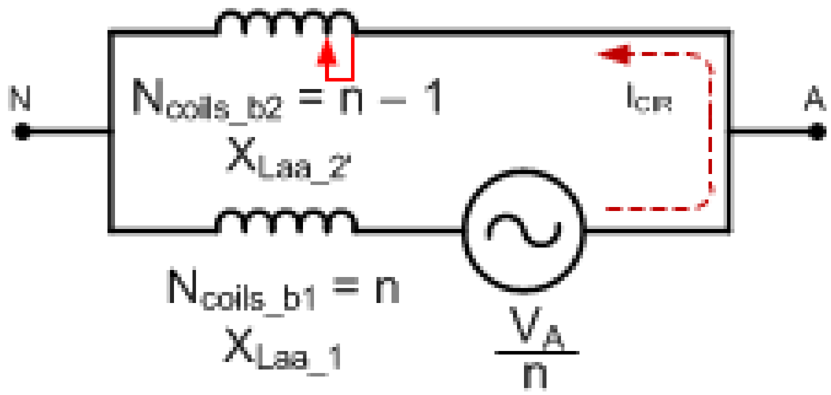
Differential Protection scheme for split-phase windings type of generator:

two sets of differential relays in each phase.

Generator Split-Phase Protection

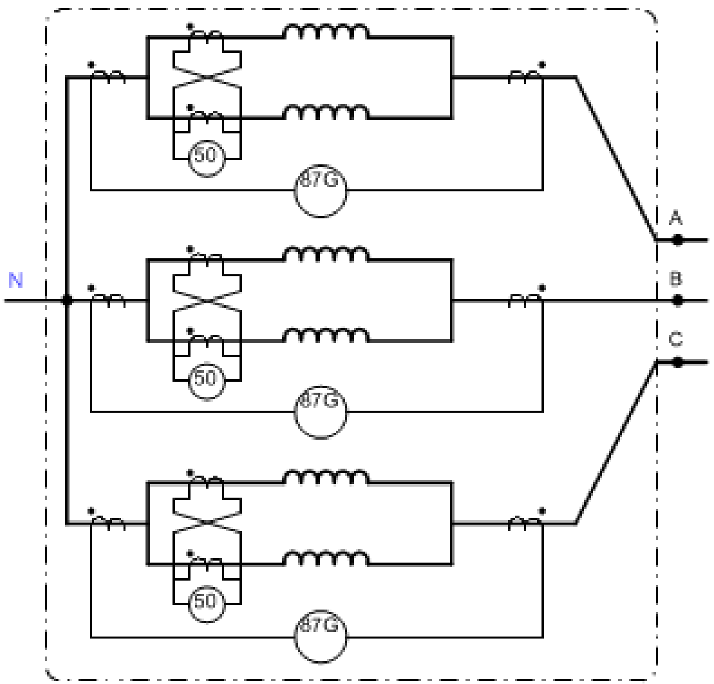


Turn-to-turn fault in a two-winding machine

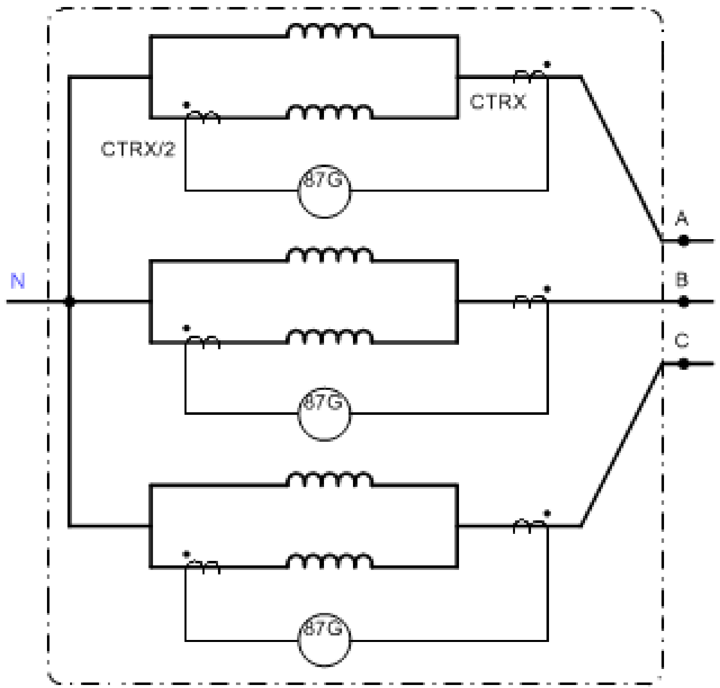


Simplified equivalent circuit for a turn-to-turn fault in a machine

Generator Split-Phase Protection



(a)

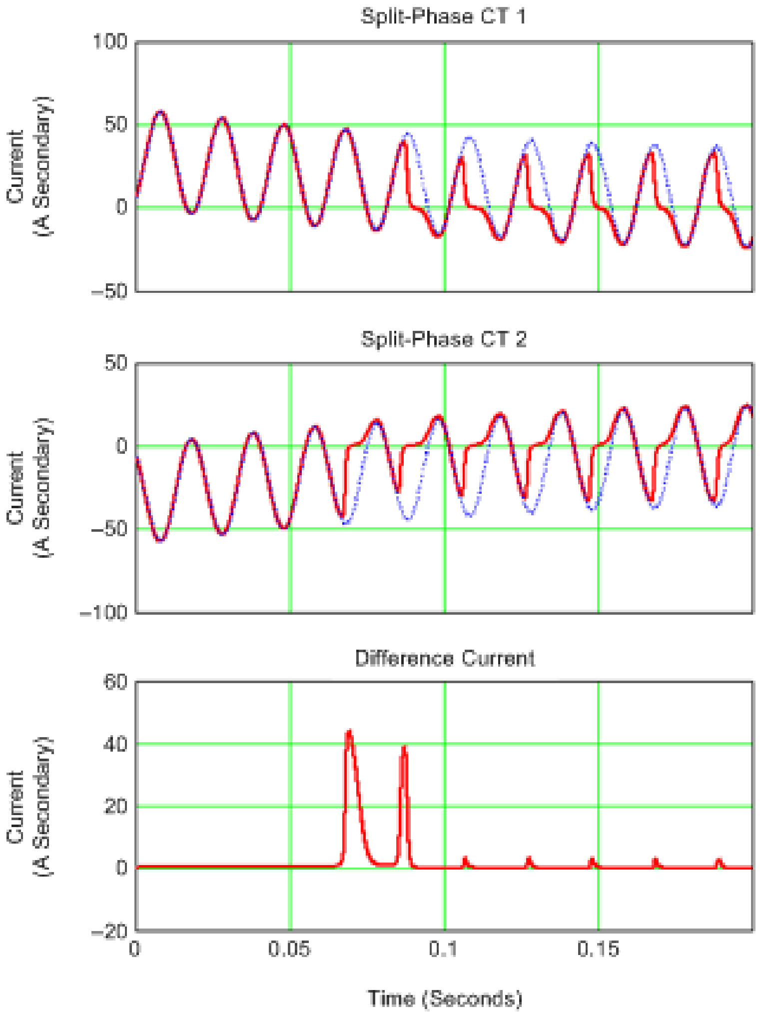


(b)

Protection scheme with dedicated stator phase-winding differential and split-phase protection elements.

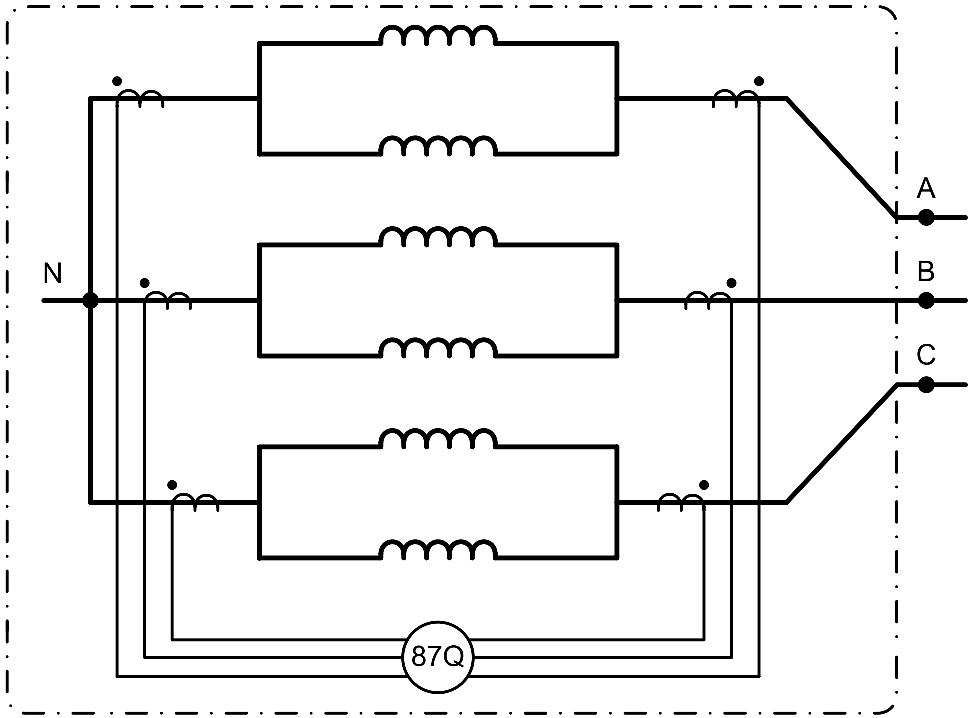
A single protection scheme combining stator phase-winding differential and split-phase protection.

Problems with Differential Protection



Unequal saturation of the CTs in a split-phase protection scheme resulting in a fictitious differential current.

Generator Split-Phase Protection

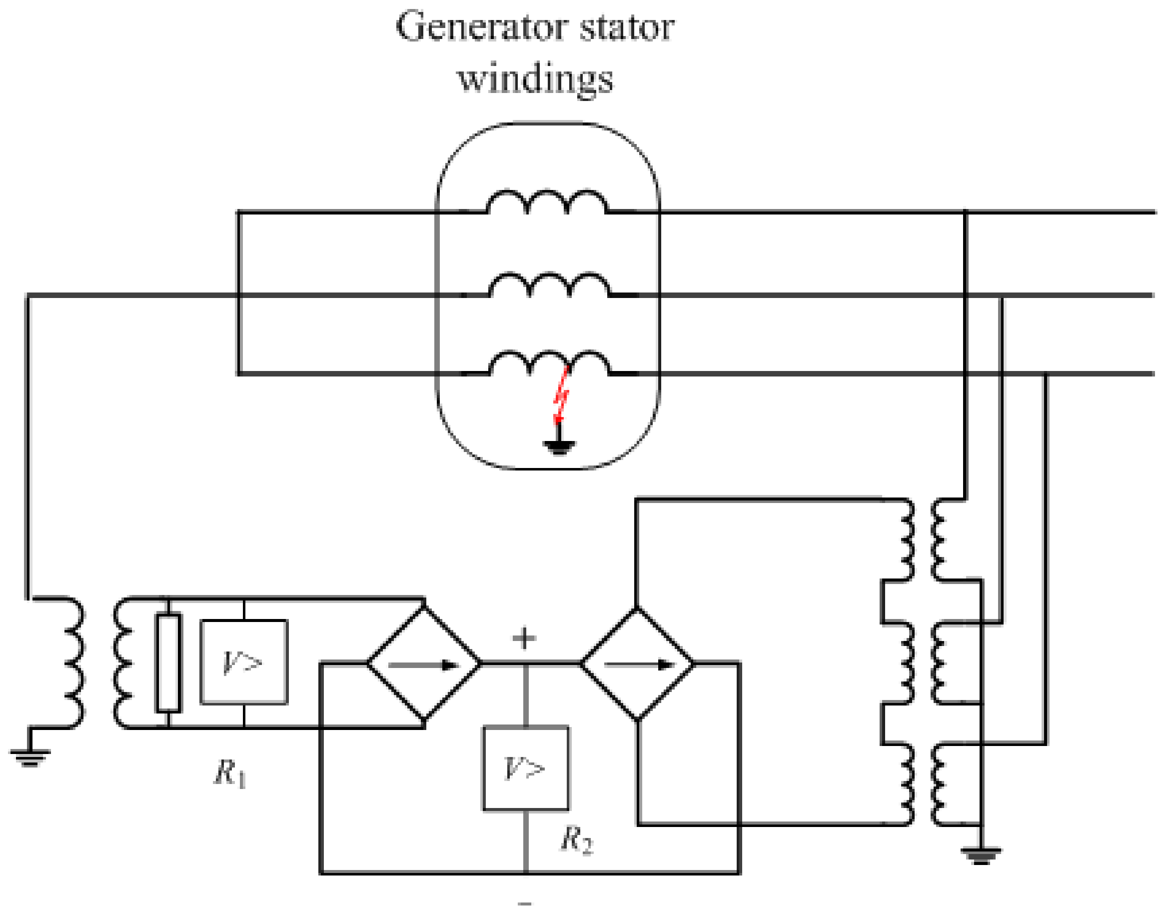


Negative-sequence protection scheme that can be applied to detect turn-to-turn faults.

Stator Ground Fault Protection

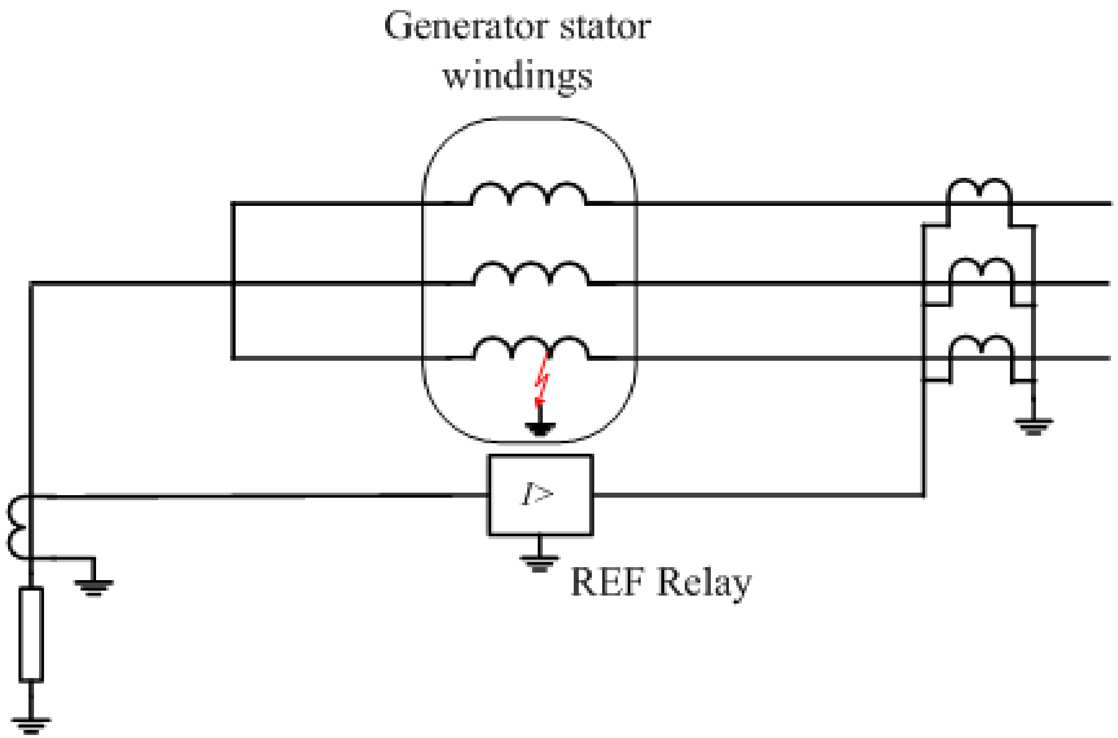
1. Single phase-to-ground fault is not hazardous (for isolated or high-impedance grounded system).
2. A second ground fault at the machine terminal, however, causes a line-to-ground fault that is not limited by any neutral impedance.
3. This fault current magnitude will quite likely exceed the current magnitude for which the machine is designed.
4. Machine destruction may result. Early detection, then, is imperative.
5. Typical solution compares the third harmonic voltage present between the machine neutral and ground with that at the line terminals.

Stator Ground Fault Protection



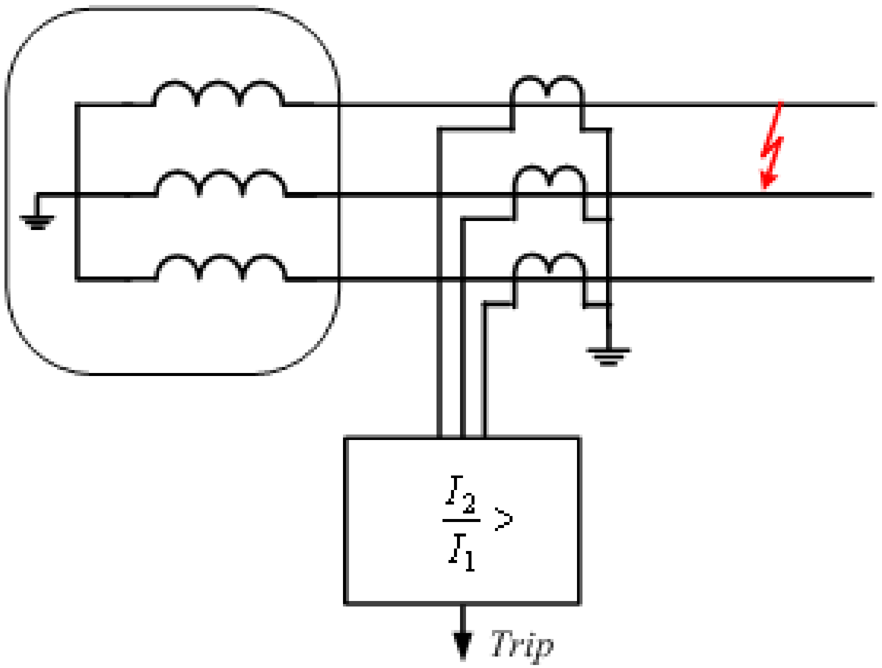
Third harmonic voltage comparator for high-impedance grounded stator

Stator Ground Fault Protection



Ground fault protection for low-impedance grounding system
REF – Restricted Earth Fault (protection)

Protection against unbalanced external faults



$$\underline{I}_1 = \frac{1}{3}\left(\underline{I}_A + a\underline{I}_B + a^2\underline{I}_C\right)$$

$$\underline{I}_2 = \frac{1}{3}\left(\underline{I}_A + a^2\underline{I}_B + a\underline{I}_C\right)$$

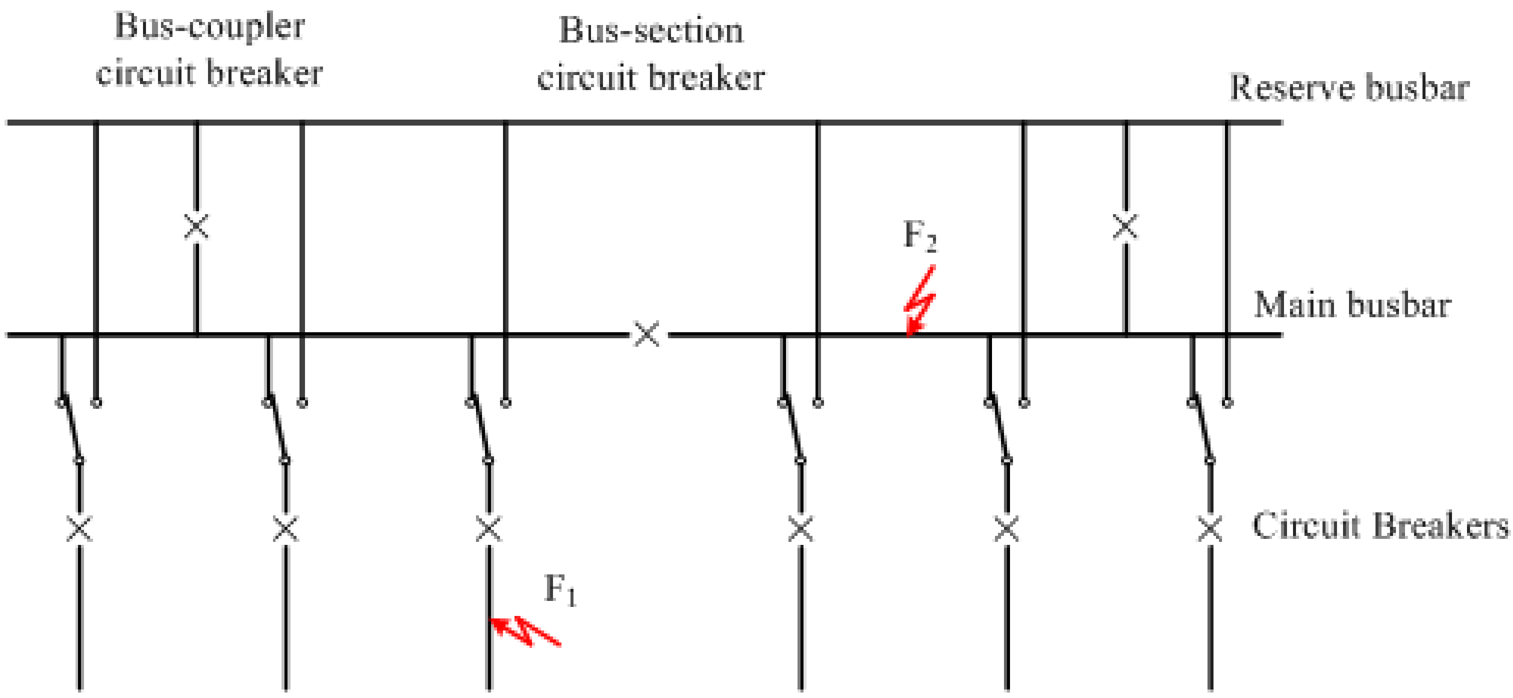
$$a = e^{j2\pi/3}$$

Protection against unbalanced external faults – criterion based on increasing of negative sequence current

The Protection of Busbars

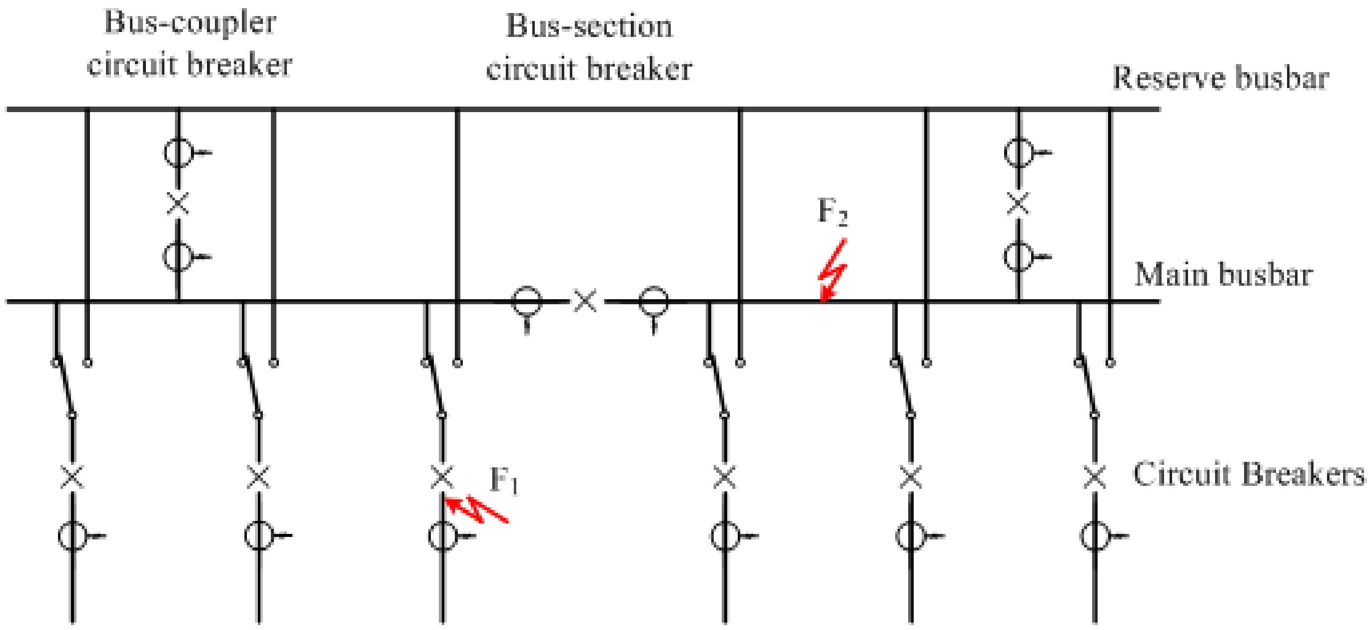
- **Busbars are vital elements of power systems because they link incoming circuits connected to sources, to outgoing circuits which feed loads.**
- **When a bus fault occurs, all branches supplying current to that node must be opened to clear the fault. Such disconnection clearly causes considerable disruption and the greater of the operating voltage and current levels of a busbar, the greater will be the loss of supply resulting from a fault.**
- **The most common protection schemes are based on Kirchhoff's current low: all branch currents into a node sum to zero.**

The Protection of Busbars



Busbar arrangement. Inside and outside faults shown.

Percentage Differential Protection

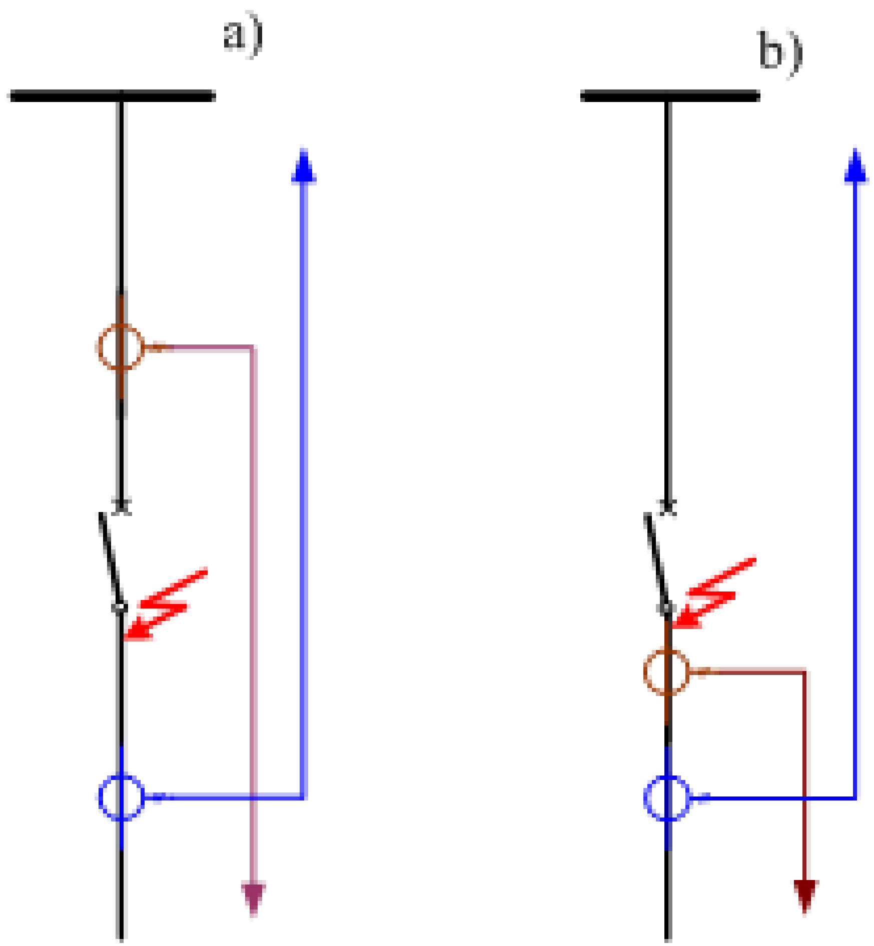


$$I_{OP} = \left| \underline{I}_1 + \underline{I}_2 + \cdots + \underline{I}_n \right| \qquad I_{RT} = k\left(\left|\underline{I}_1\right| + \left|\underline{I}_2\right| + \cdots + \left|\underline{I}_n\right| \right)$$

k **– scaling factor**

Special problem with fault at F1 – incorrectly opening of the section

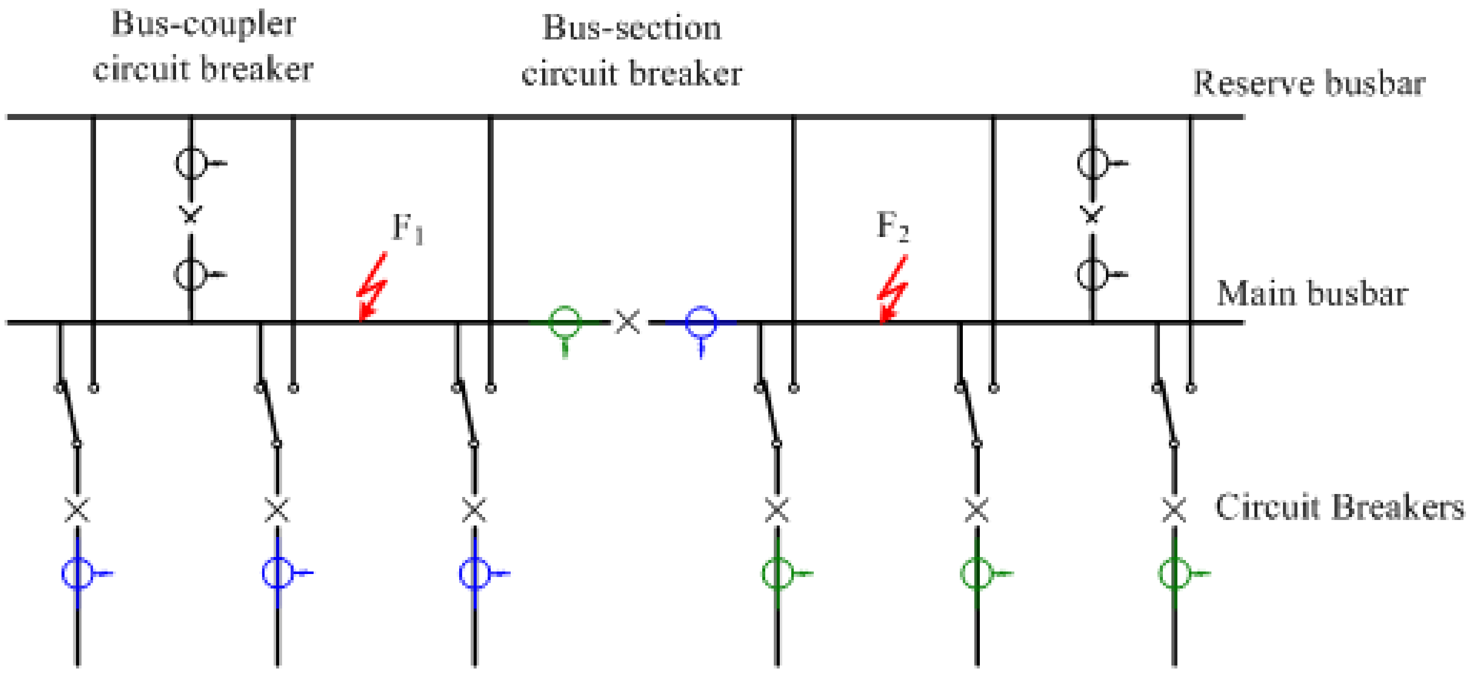
Problem with Unprotected Zone



a) **Current transformers mounted on both sides of breaker - no unprotected region.**

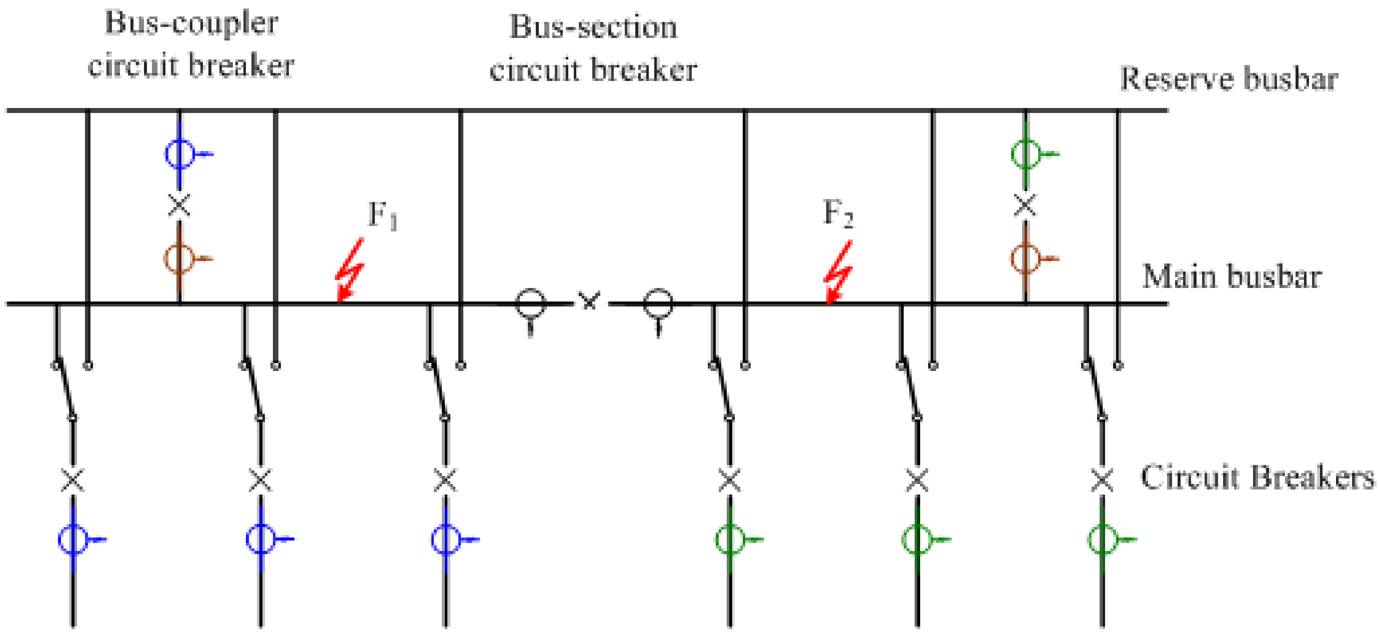
b) **Current transformers mounted on circuit side only of breaker - fault shown not cleared by circuit protection.**

Protected zones



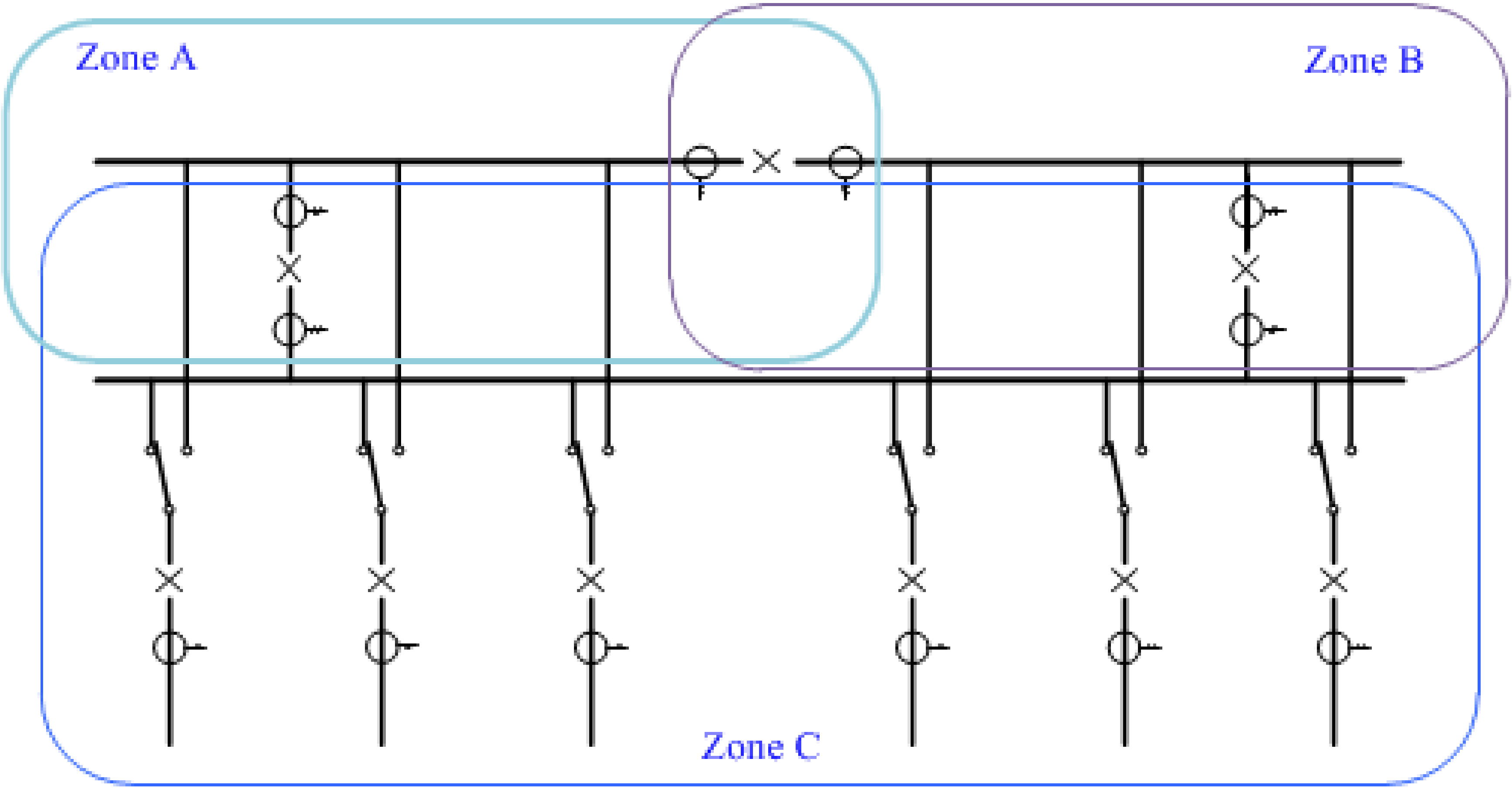
Bus-section CB – closed, Bus-couplers - opened

Protected zones



Bus-section CB – opened, Bus-couplers - closed

Protected zones



Local Backup and Breaker Failure Protection

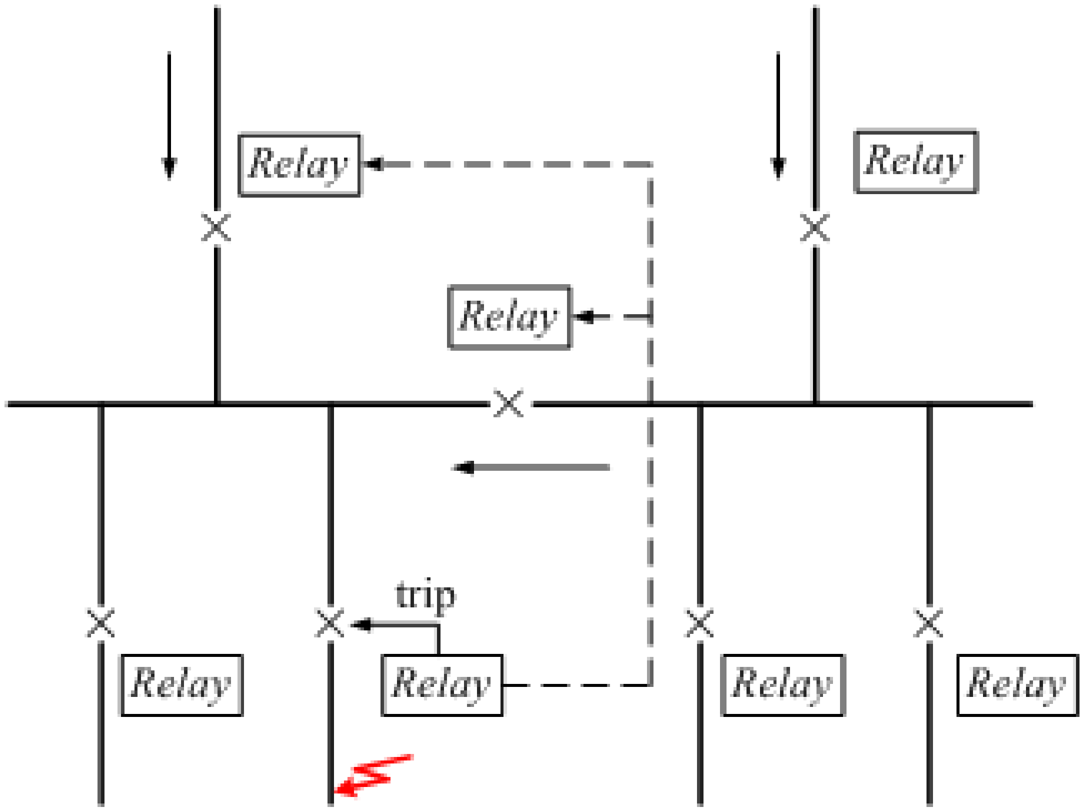
- **There are various reasons for a circuit breaker to fail to interrupt or trip but breakers are almost never redundant because of their high cost.**
- **Unlike remote line protection, local backup is applied at the local station. If the local breaker fails, either the primary or backup relays will initiate the breaker-failure protection to trip other breakers adjacent to the failed breaker.**
- **Breaker failure protection is a high speed protection scheme that will trip surrounding breakers in the event that a circuit breaker fails to clear a fault.**

Local Backup and Breaker Failure Protection

A breaker will be considered to have failed if, after the trip signal has been generated, the breaker has:

- **not started opening within a preset time frame (determined by switches internal to the breaker),**
- **the breaker has not fully opened within a preset time frame (determined by switches internal to the breaker), or**
- **if the current has not been broken by the breaker within a preset time (determined by current measurement devices).**

Local Backup and Breaker Failure Protection



Distributed RF protection scheme

Bus Transfer Technique

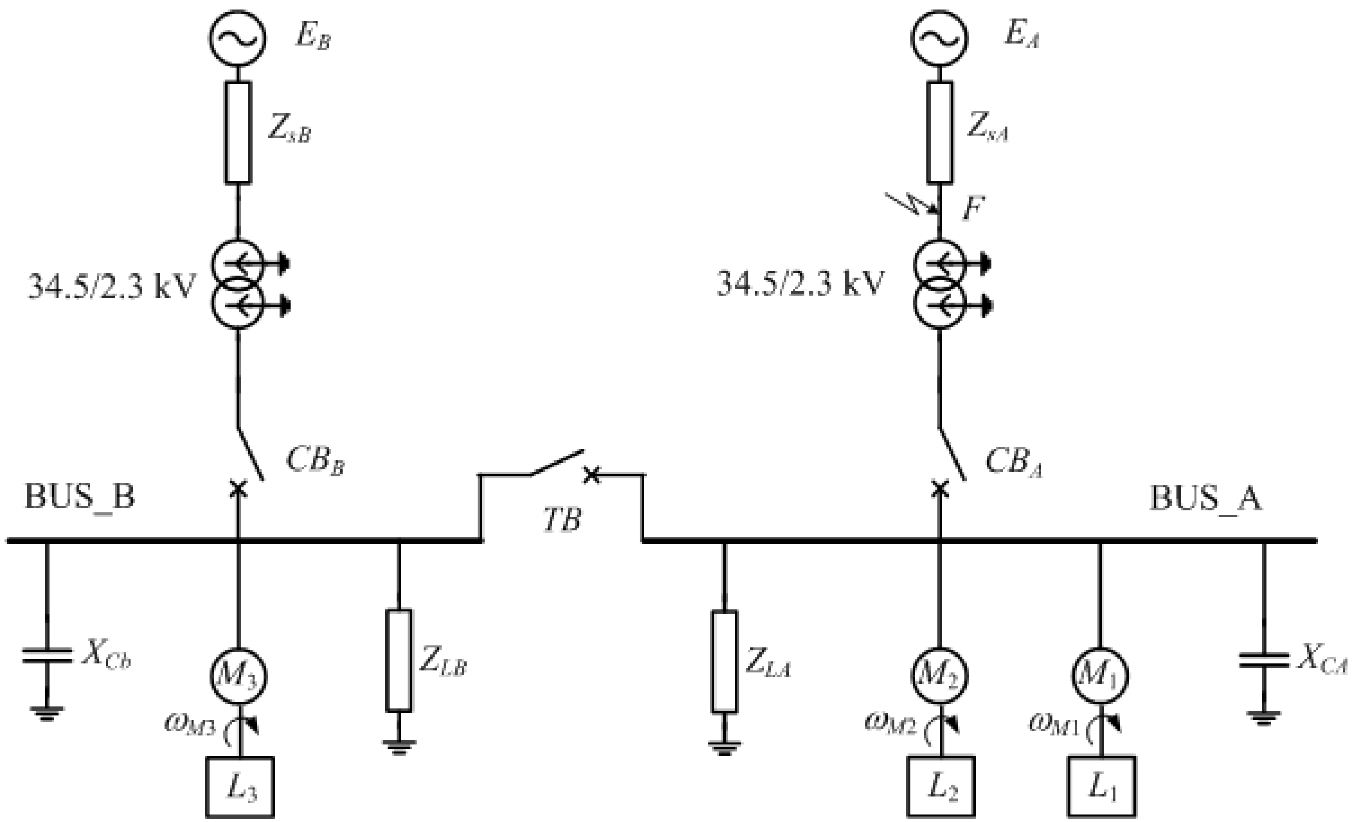
- **A transfer switch is an electrical switch that reconnects electric power source from its primary source to a standby source.**
- **Transfer switches transfer electrical power back and forth between two or more power systems or buses such as a utility power line and a backup generator. They are used in applications that require a backup power source where loss of power could cause problems.**
- **Some transfer switches allow switching from a primary to a secondary, or even a tertiary power source. Others are used to switch from a regular power source to a temporary generator.**

Motor Bus Transfer Technique (MBT)

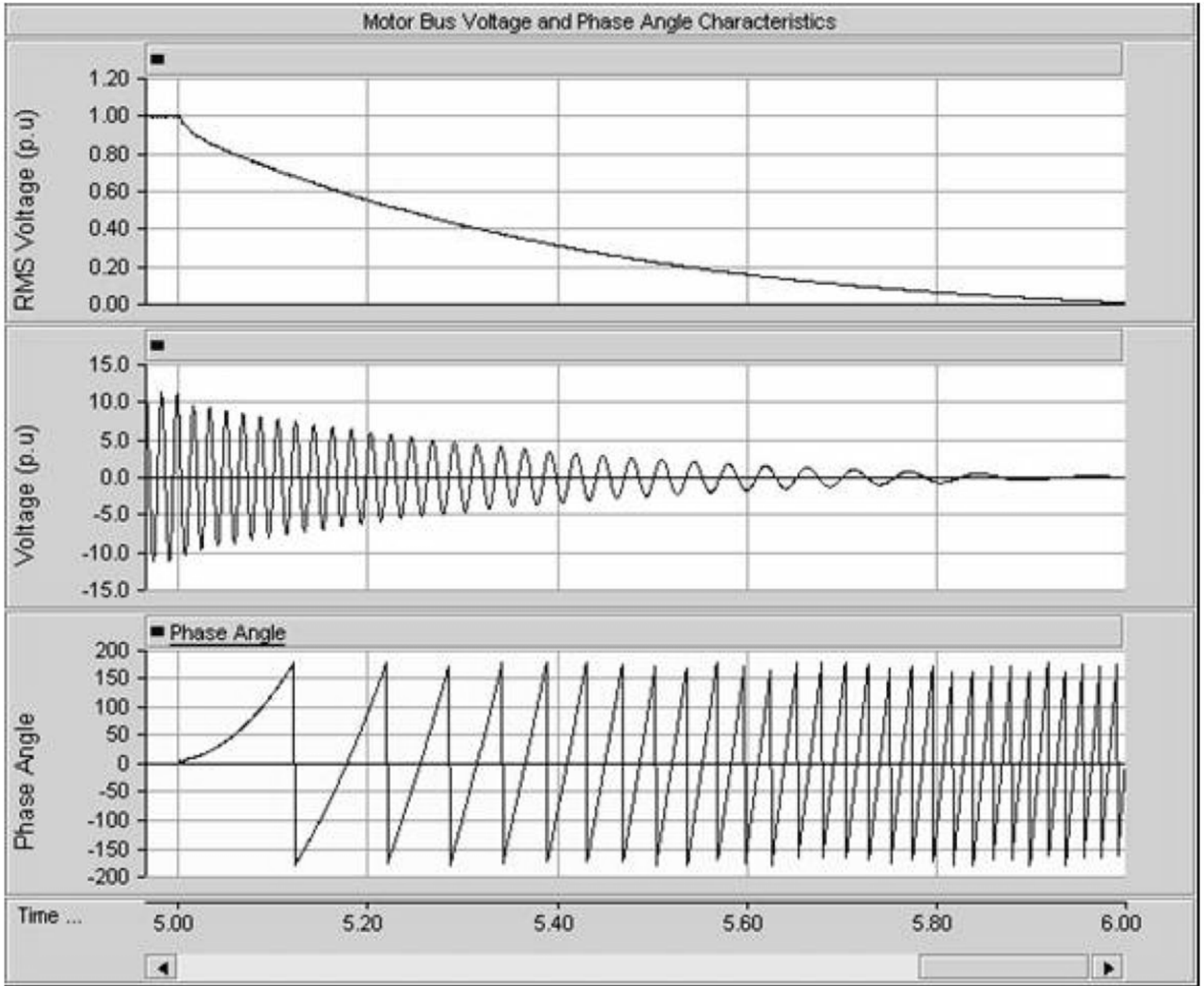
Required to maintain continuity of critical processes in a generating or industrial plant during the following periods

- **Planned transfers**
  - **Maintenance or startup/shutdown**
- **Emergency transfers**
  - **Loss of present source due to a fault**
- **A poor transfer can result in a significant angle between the new source and the motor bus at the instant of closing.**
  - **This results in very high transient torque and current.**
  - **Damage can be immediate or cumulative.**

Motor Bus Transfer Scheme



TB open, fault at F


Motor Bus Voltage and Phase Angle Characteristics
RMS Voltage (p.u)
1.20
1.00
0.80
0.60
0.40
0.20
0.00
Voltage (p.u)
15.0
10.0
5.0
0.0
-5.0
-10.0
-15.0
Phase Angle
200
150
100
50
0
-50
-100
-150
-200
Time ...
5.00
5.20
5.40
5.60
5.80
6.00

Motor Bus Transfer Characteristic:
spin-down phase angle