Power System Protection

EE454

(Chapter 7 finished – Chapter 8 started)

Lecture file # 7

ODL Week (Dec. 14 – Dec. 18)

- **Note:**

The materials in this presentation are only for the use of students enrolled in this course in the specific campus; these materials are for purposes associated with this course and may not be further disseminated or retained after expiry of the course.

Session No.	Content of the Lecture presentation (from Ch#7 & 8 of PS Relaying)
Lect. 1	Ground fault protection for rotating machinery - Examples of motor protection
Lect. 2	Abnormal Conditions for Rotating Machinery: Rotor Faults, Unbalanced Currents, Overload, OverSpeed. Intro. to Transformer Protection, Use of Percentage Differential Relay
Lect. 3	Numerical Example of % dif. protection for single phase transformer. Inrush current and diff. relay with harmonic restraint, Three phase transformer diff. protection


بسم الله الرحمن الرحيم

7.2.2 *Ground fault protection*

When the generator is solidly grounded, as in Figure 7.7, there is sufficient phase current for a phase-to-ground fault to operate almost any differential relay.

The higher the grounding impedance, the less the fault current magnitude and the more difficult it is for the differential relay to detect low-magnitude ground faults.

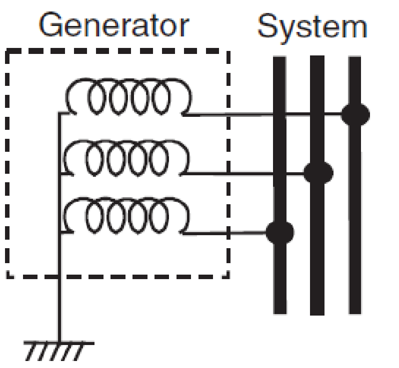


Figure 7.7 Direct connected and solidly grounded generator

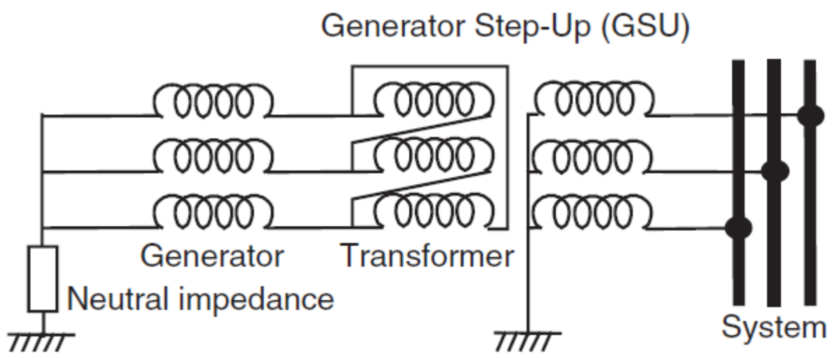


Figure 7.8 Neutral impedance grounding

If a CT and a relay are connected between ground and the neutral point of the circuit, as shown in Figure 7.9, sensitive protection will be provided for a phase-to-ground fault since the neutral relay (51N)† sees all of the ground current and can be set without regard for load current.

If the machine is solidly (or low-impedance) grounded, and protected with a neutral CT and relay 51N as shown in Figure 7.9, an instantaneous overcurrent relay is applicable.

In high impedance systems, a time delay relay is preferred: it would be set with sufficient time delay, e.g. 5–10 cycles, to override any false ground current that could be caused by switching or other system transients.

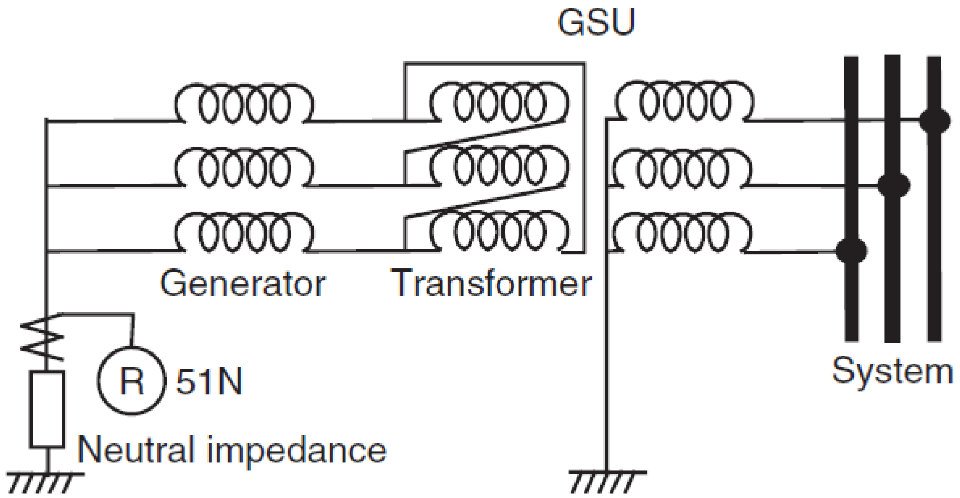


Figure 7.9 Neutral impedance grounding with neutral CT and relay (GSU, generator step-up)

Example 7.4

Referring to the system diagram and the sequence networks shown in Figure 7.10, the phase current for the differential relay (87) and the neutral relay current (51N) for various values of grounding impedances are as follows.

(a) Solidly grounded: $R_n = 0$

$$I_1 = I_2 = I_0 = \text{j}1.0/\text{j}(0.2 + 0.2 + 0.03) = 2.33 \text{ pu} \times 4656 = 10\,828.35 \text{ A}$$

$I_g = I_a = 3 \times I_0 = 32\,485$ A primary. The secondary current in the generator differential relay will be 32.5 A. The typical minimum pickup of this class of relay is 0.2–0.4 A so 32.5 A is sufficient to reliably operate on ground faults even with additional resistance or within the generator winding.

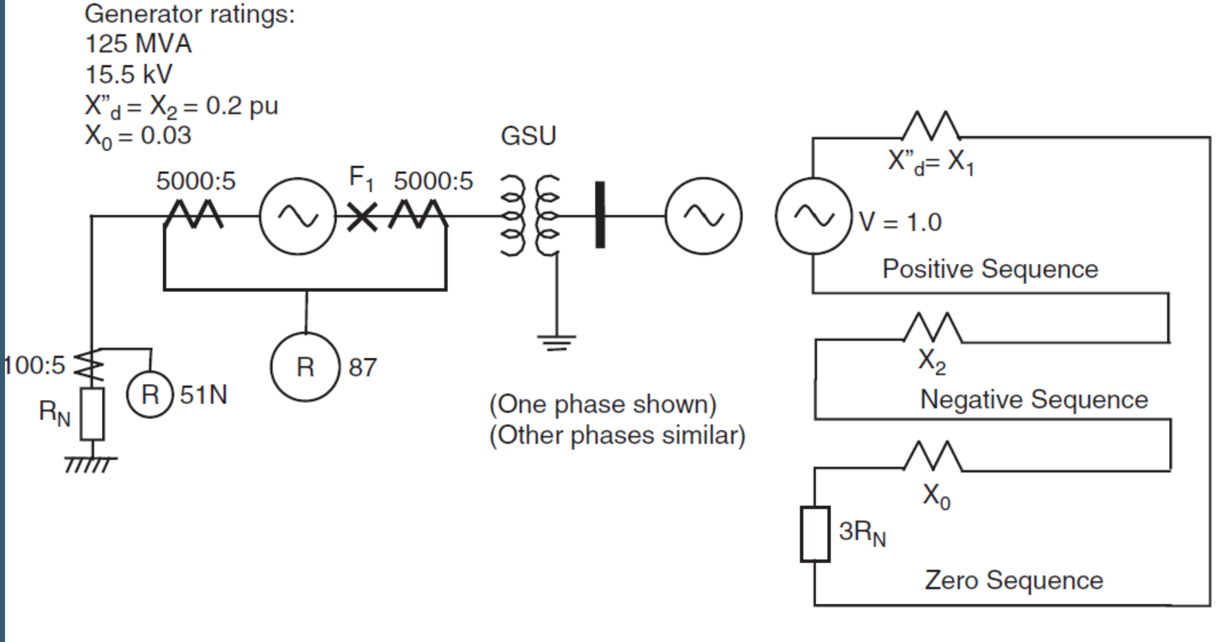


Figure 7.10 System and sequence networks for Example 7.4

(b) Moderately grounded: $R_n = 1.0\ \Omega$

$$1.0\ \Omega = [(1) \times (125\,000)]/[(1000) \times (15.5)^2] = 0.52 \text{ per unit}$$

$$I_1 = I_2 = I_0 = \text{j}1.0/[3(0.52) + \text{j}0.43] = 0.617\angle 74.60^\circ \text{ per unit}$$

$I_g = I_a = 3 \times I_0 = 8618$ A primary. The generator differential CT secondary will be 8.62 A, which is still adequate. However, if a neutral CT and relay were installed, the CT ratio could be as low as 100:5 which would result in a neutral relay current of 431 A.

(c) High-impedance grounding: $R_n = 10\ \Omega$ohms

$$10\ \Omega = 5.2 \text{ pu}$$

$$I_1 = I_2 = I_0 = \text{j}1.0/[3(5.2) + \text{j}0.43] = 0.06\angle 1.5^\circ$$

$I_g = 3I_0 = 837$ A primary. The generator differential secondary current (0.84 A) is above pickup but does not allow for additional fault resistance. The neutral relay current (41.85 A) is sufficient to make a good relay setting.

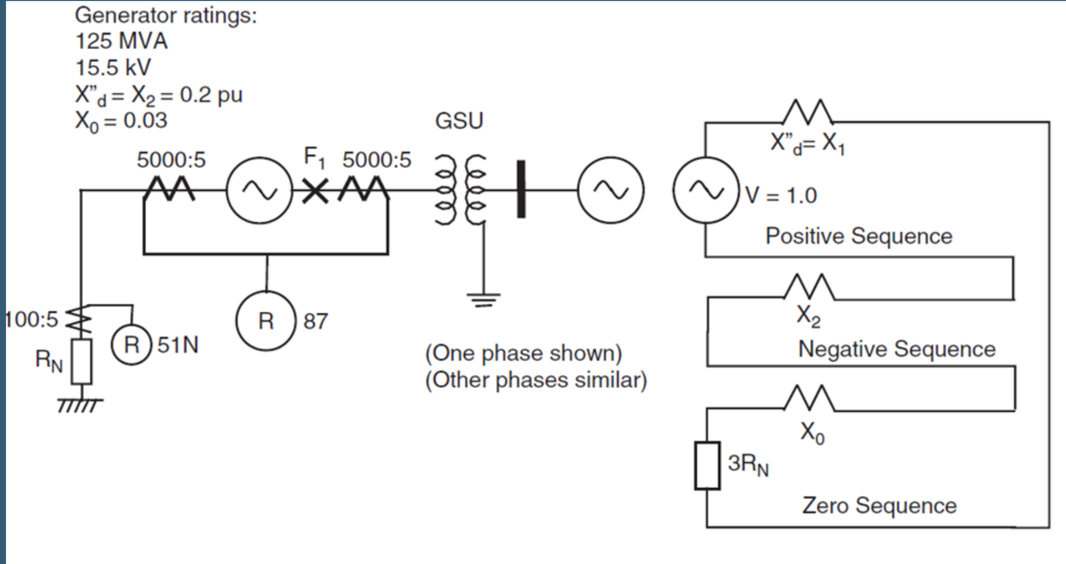


Figure 7.10 System and sequence networks for Example 7.4

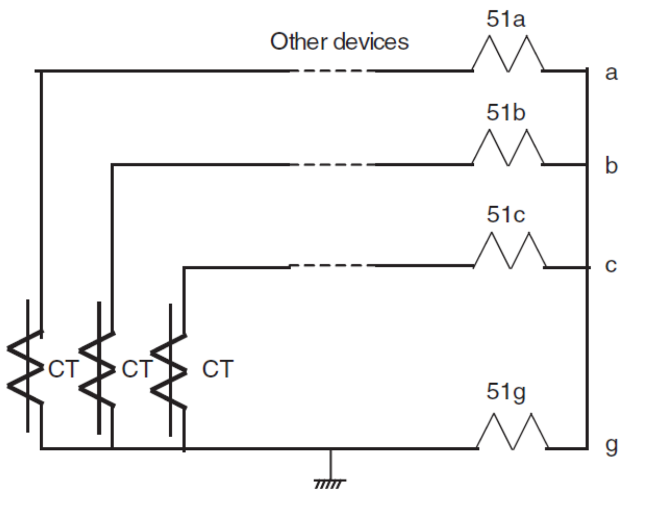


Figure 7.12 Residually connected ground relay

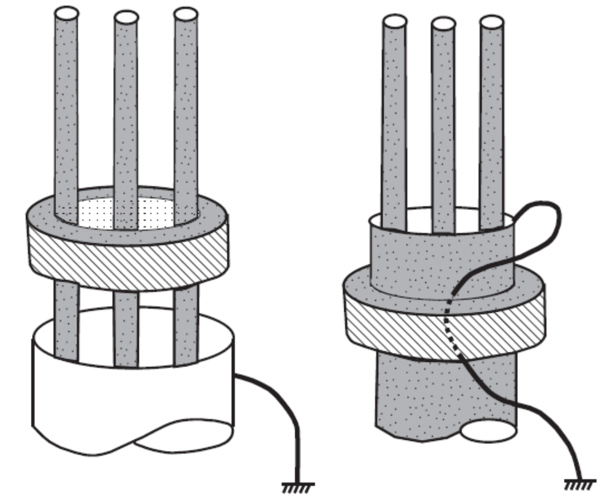


Figure 7.13 Toroidal CT

If the neutral is not accessible, or there is no neutral CT, an alternative protection scheme to the neutral relay is a residually connected relay, as shown in Figure 7.12.

An alternative to the residually connected ground relay in motor applications is the toroidal CT, shown in Figure 7.13 and discussed in section 3.4.

Example 7.5

Consider the 2000 hp motor installation shown in Figure 7.14. The CT ratio is selected to provide some margin above the trip setting so meters will not read off-scale. Normally, overcurrent relays are set at 125 % of full load and the CT ratio should allow less than 5.0 A for this condition. If the motor is vital to the operation of the plant, advantage is taken of the motor service factor which is 115 %. This results in a maximum load of 245 A × 1.15 = 282 A and a relay pickup setting of 1.25 × 282 = 352.5 A. Select a CT ratio of 400:5 (80:1).

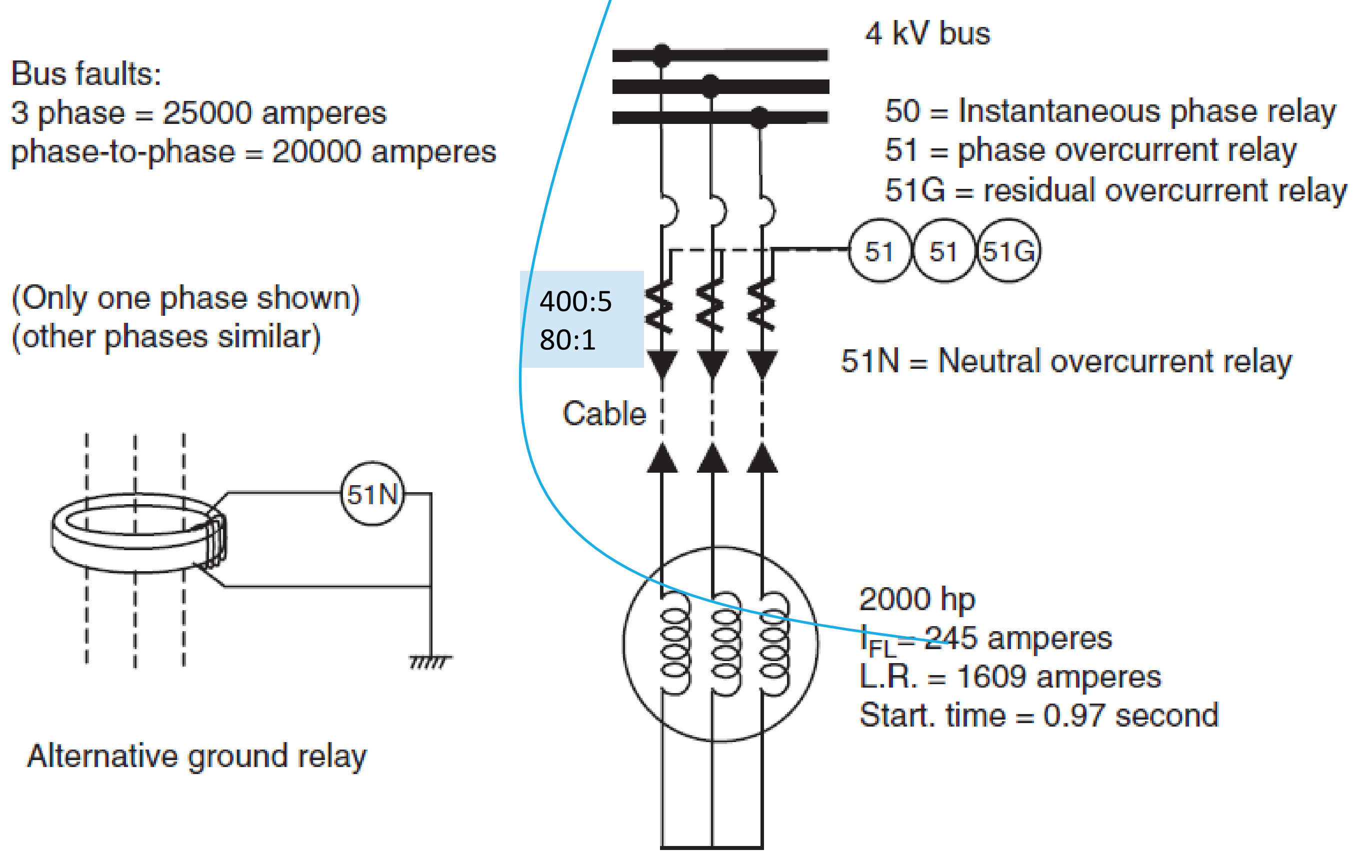
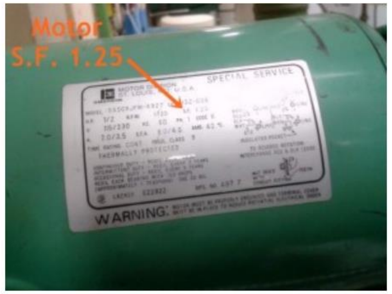


Figure 7.14 Protection for 2000 hp motor

What is a Motor Service Factor?

Motor service factor (SF) is the percentage multiplier that a motor can handle for short periods of time when operating within its normal voltage and frequency tolerance. In other words, it is a fudge factor that give extra horsepower when it's occasionally needed.



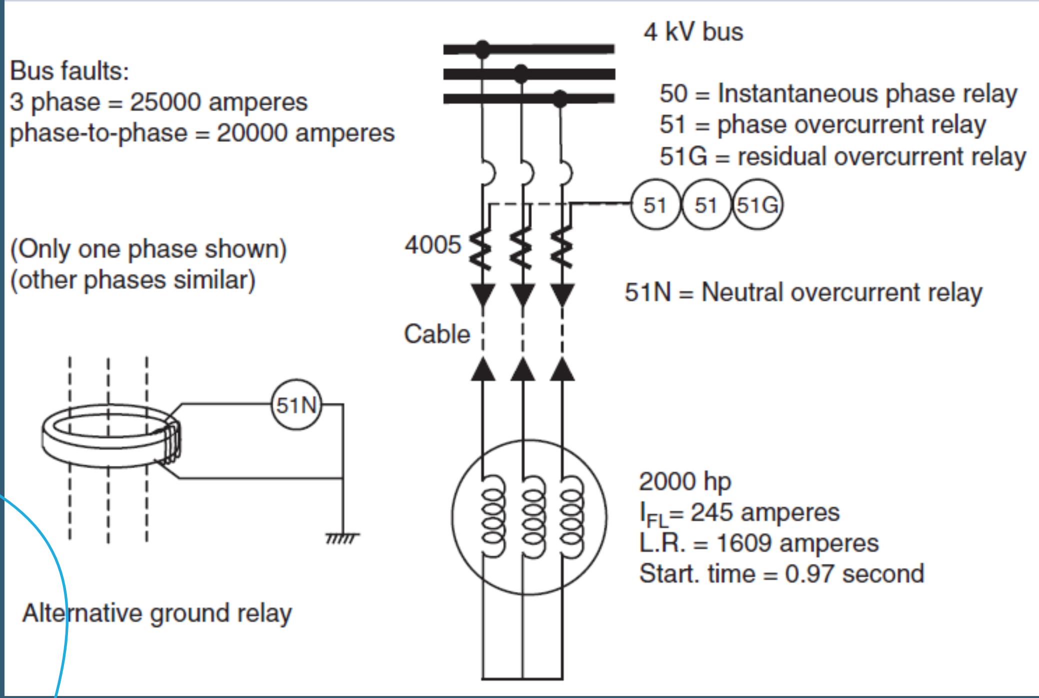
A SF is an operational margin.

For instance, this 1/2 horsepower shown in the photo has a service factor of 1.25 so it can actually output 25% more power required for short periods of time. This comes in handy if the density of the liquid increases or a higher than normal flow rate is required.

http://www.icsenggroup.com/motor-service-factor.shtml

Example 7.5 contd.
Setting Time Delay Relays

The time-delay overcurrent relay 51 sees 352.5/80 or 4.4 secondary amperes. To set the relay, the manufacturer's instruction book and characteristic curves must be used. For our purposes, however, assume there is a 5.0 A tap and the characteristics of Figure 4.5 apply. The time delay must be set longer than the starting time of the motor. This assumes that the starting current lasts for the full starting time. This is not strictly true. The starting current starts to decrease at about 90% of the starting time. However, this is a conservative setting that is often used to cover any erratic motor behavior and to avoid false tripping during starting. The relay pickup during starting is $1609/(80 \times 5) = 4 \times$ pu; the time delay must be at least 0.97 s which results in a time dial setting of 1.5. Two overcurrent relays are usually used, one in phase 1 and the other in phase 3, on the assumption that an overload is a balanced load condition. An ammeter (not shown) is usually connected in phase 2.



The relay Iactual/Ipickup is 4 i.e. 4xpu.

Setting inst. Relay

Inst. Relay is not shown in figure – assume it to be present in place of time delay relays. Assume a phase-phase fault on the motor side to give 20kA.

The instantaneous relay 50 must be set above the asymmetrical value of the locked rotor current, i.e. $1.7 \times 1609 = 2735$ primary amperes or 34.19 secondary amperes. Set at 35 A. Check for pickup at minimum 4 kV bus fault; $20\,000/(35 \times 80) = 7.14 \times$ pu. Three relays are used, one per phase, to provide redundancy for all phase faults.

Setting Ground Protection

The residual overcurrent relay 51G is set at one-third of the minimum ground fault. If the auxiliary system has a neutral resistor to limit the ground fault to 1200 A,‡ the residual CT current will be $1200/80 = 15$ A. Set the relay at 5.0 A or less to ensure reliability without setting it at the lowest tap to avoid loss of security. Set the time dial at a low setting. There are no criteria for these settings except what is the usual practice at a given plant.

If the alternative scheme using a toroidal CT is used, the CT ratio can be 1200:5 (240:1) and an instantaneous relay set at 1.0 A. This will give 5 times pickup at the maximum ground fault current and provide sufficient margin above any false ground currents to prevent false tripping and still allow for reduced ground fault current due to fault resistance.

Example 7.6

Figure 7.15 shows a 7500 hp motor connected to the same auxiliary bus as the motor in Example 7.5. The time-delay overcurrent relays follow the same setting rules as for the 2000 hp motor.

Setting Phase Relay

The pickup of the two phase overcurrent relays 51 is equal to $1.15 \times 1.25 \times 918$ or 1320 primary amperes.

Select a CT ratio of 1500:5 (300:1). The relay pickup tap is therefore $1320/300 = 4.4$; use the 5.0 A tap. Pickup during starting is $5512/(5 \times 300) = 3.7 \times$ pu and the time delay must exceed 3 s. From Figure 4.5, use #6 dial.

Setting ground relay

The residual overcurrent relay 51G is set at one-third of the limited ground current $(1200/300 = 4)$ or 1.33 A. Use the 1.0 A tap and the same dial setting as in Example 7.5. If a toroidal CT is used, the setting rules used in Example 7.5 apply.

Setting inst. phase Relay

The setting of the instantaneous relays, however, introduces a problem. Using the criteria of Example 7.5 we should set the relays at 1.7×5512 or 9370 A. Since the minimum 4 kV bus fault is 20 000 A we would only have $2.1 \times$ pu. This is not enough of a margin to ensure fast tripping. For a motor of this size we would use three differential relays (87). There is no setting required since the sensitivity of the differential relay is independent of the starting current.

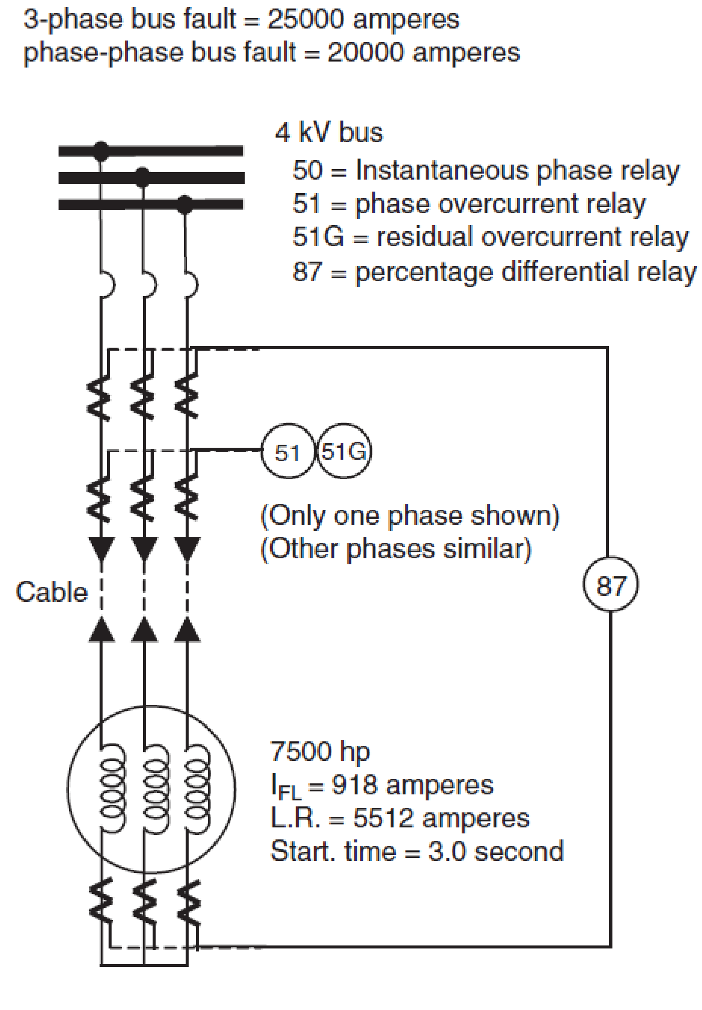
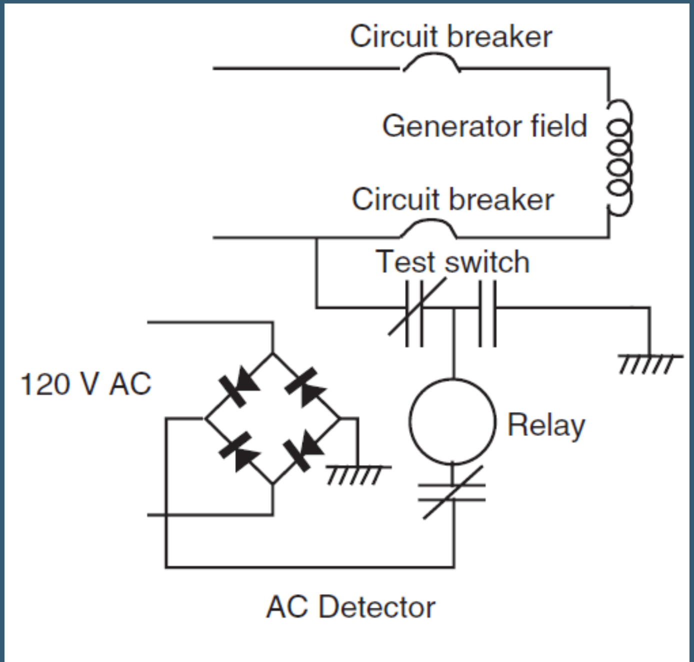
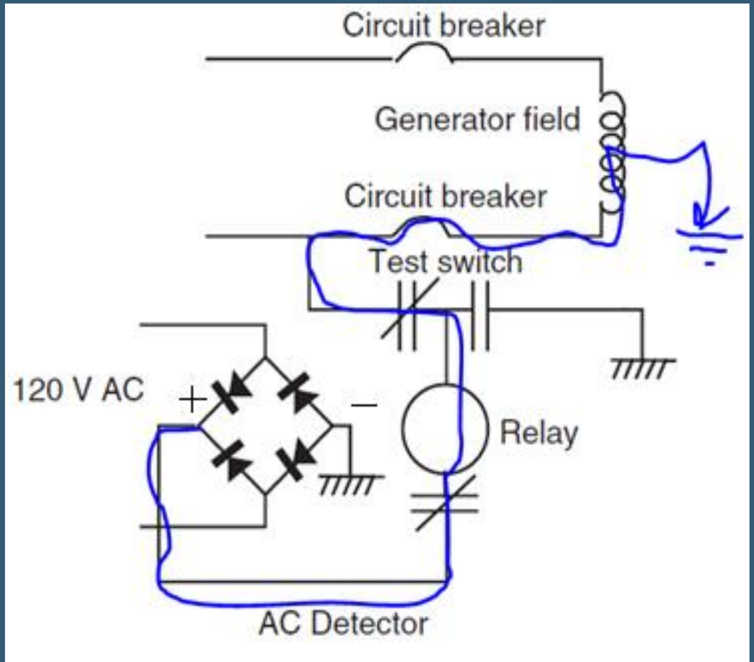


Figure 7.15 Protection for 7500 hp motor

7.3 Rotor faults

The field circuits of modern motors and generators are operated ungrounded. Therefore, a single ground on the field of a synchronous machine produces no immediate damaging effect. However, the existence of a ground fault stresses other portions of the field winding, and the occurrence of a second ground will cause severe unbalance, rotor iron heating and vibration. Most operating companies alarm on the indication of the first ground fault and prepare to remove the unit in an orderly shutdown at the first opportunity.





7.4 Unbalanced currents

Unsymmetrical faults may produce more severe heating in machines than symmetrical faults or balanced three-phase operation. The negative sequence currents which flow during these unbalanced faults induce 120 Hz rotor currents which tend to flow on the surface of the rotor forging and in the nonmagnetic rotor wedges and retaining rings. The resulting I^2R loss quickly raises the temperature. If the fault persists, the metal will melt, damaging the rotor structure.

Industry standards have been established which determine the permissible unbalance to which a generator is designed. The general form of the allowable negative sequence current is $I_2^2 t = k$ (I_2 is the per-unit negative sequence current; t is the time in seconds). For directly cooled cylindrical rotors up to 800 MVA, the capability is 10. Above 800 MVA the capability is determined by the expression $[10 - (0.00625)(\text{MVA} - 800)]$. For example, a 1000 MVA generator would have an $I_2^2 t = 8.75$. No standards have been established for motors, although $k = 40$ is usually regarded as a conservative value.

When such an unbalance occurs, it is not uncommon to apply negative sequence relays (46) on the generator to alarm first, alerting the operator to the abnormal situation and allowing corrective action to be taken before removing the machine from service. The relay itself consists of an inverse time-delay overcurrent relay operating from the output of a negative sequence filter.

Negative sequence overcurrent relay and protection assemblies
RXIIK 4 and RAIIK 400

(RXIIK4.tif) (se980083.eps)

RXIIK 4 relay

- Negative sequence overcurrent relays are used to detect unbalanced load on a generator which may cause excessive rotor heating. The relay is also used to detect unbalanced load currents in motors.
- The relay can also be used in the other applications such as:
  - Unsymmetrical load which increase the negative sequence current.
  - Phase interruptions e.g. a broken conductor.
  - Failure on one or two poles of a breaker or disconnect-switch at opening and closing
- Earth-fault detection in solidly earthed system.
- The relay has I-Start, I-Alarm, I-Trip and Blocking functions.
- Three current ranges: I_r = 1 A, I_r = 2 A and I_r = 5 A
- Set range I-Start 4-40% of I_b (machine current) with inverse characteristic
  t = K x (lb /I-)^2;
  K= 0-100 seconds or
  definite time = 0-100 minutes.
- Set range I- Alarm 3-30% of I_b (machine current) with definite time = 0-100 seconds.
- Thermal memory for block and trip function with the settable cooling time up to 200 minutes
- Reset time I-Trip = 0-5 seconds.
- Five independent output relays selectable for In Service, I-Start, I-Alarm, I-Trip, Blocking as well as Group 2 active.
- Easy selectable setting of parameters through the HMI.
- Trip information available via the HMI.
- Two groups of setting parameters are settable and readable through the HMI. The active setting group 1 or 2 can be selected through one of the two binary inputs.
- Selectable binary inputs to block or enable I-Start, I-Alarm, I-Trip, change active group and reset of LED and timer.
- Testing of the output relays and operation of binary inputs can be performed through the HMI.
- Service values are available through the HMI.
- Test switch, DC/DC converter and heavy duty trip relays are available as specified options.

7.5 Overload

In the case of generators, overload protection, if applied at all, is used primarily to provide backup protection for bus or feeder faults rather than to protect the machine directly.

Synchronous generator is not a stand alone machine, rather it is connected to the power system – in case of overload upon the system, under frequency relays may operate….

Under frequency relays are used to shed automatically certain portion of load whenever the system frequently falls to such a **low** level as to threaten the stability of the power system. ..

Under frequency load shedding (UFLS): Principles and implementation

Publisher: IEEE Cite This PDF

Y. R. Omar ; I. Z. Abidin ; S. Yusof ; H. Hashim ; H. A. Abdul Rashid **All Authors**

Abstract

Document Sections

I. Introduction

II. Ufls Scheme

Abstract:
Under frequency load shedding is implemented to restore power system frequency stability if system frequency drops below the operational set point during major disturbance such as lost of generation. Different countries/utility companies have their own philosophies in implementing the under frequency load shedding scheme. Generally, it is based on country/utility requirements, e.g. the overall power system network and the country's demographic. This paper presents the principles and implementation of

Overload protection is always applied to motors to protect them against overheating.

Thermal overload relays offer good protection for light and medium (long-duration) overloads, but may not be good for heavy overloads (Figure 7.19(a)). A long-time induction overcurrent relay offers good protection for heavy overloads but overprotects for light and medium overloads (Figure 7.19(b)). A combination of two devices can provide better thermal protection, as in Figure 7.19(c), but the complication in settings, testing, etc. weighs heavily against it and such an application is rarely used.

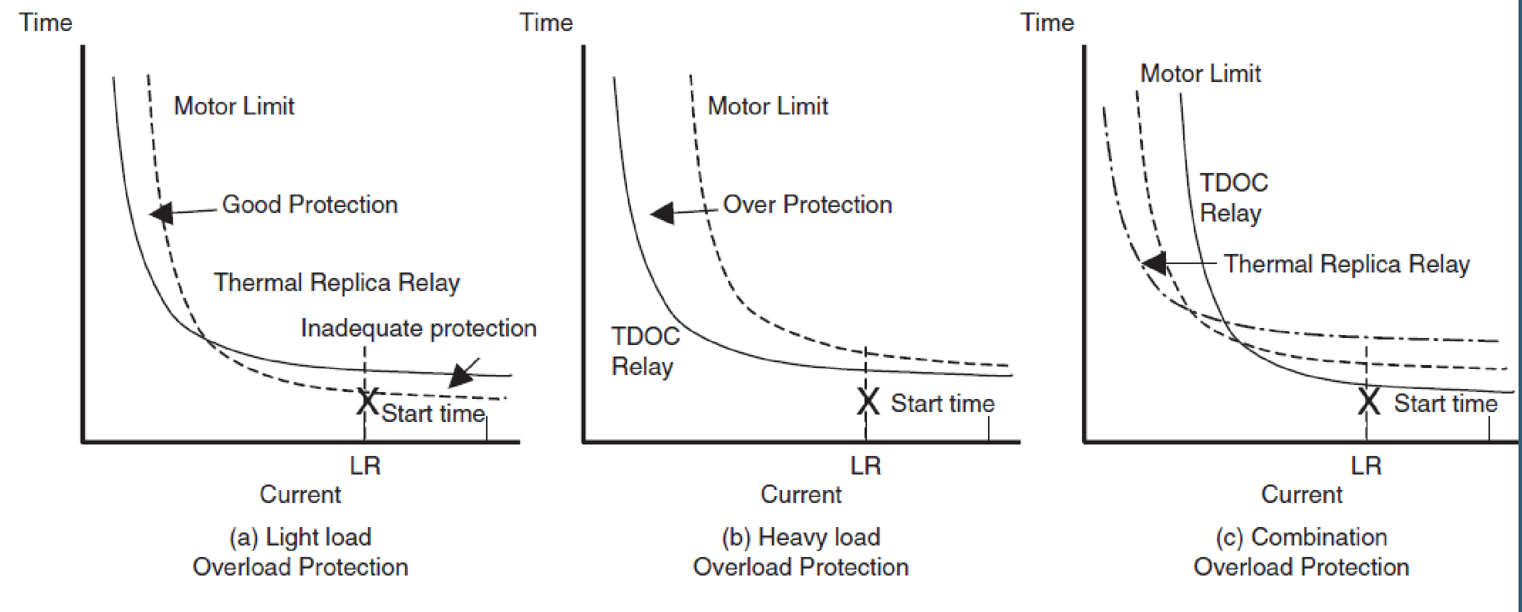


Figure 7.19 Motor overload protection (TDOC, time-delay overcurrent)

Today digital relays for motor protection are widely used to overcome the shortcomings of solid-state or electromechanical designs

Digital relays take advantage of the ability to model the rotor and the stator mathematically and use algorithms that calculate the conductor temperature resulting from operating current, add the effect of ambient temperature, and calculate the heat transfer and the heat decay. They are therefore responsive to the effects of multiple starts, the major disadvantage of using only current as an indication of temperature.

7.6 Overspeed

Overspeed protection for generators is usually provided on the prime mover. Older machines use a centrifugal device operating from the shaft. More modern designs employ very sophisticated electrohydraulic or electronic equipment to accomplish the same function. It must be recognized that, in practical situations, overspeed cannot occur unless the unit is disconnected from the system. When still connected to the system, the system frequency forces the unit to stay at synchronous speed. During overspeed the turbine presents a greater danger than the generator. Overspeed is not a problem with motors since the normal overcurrent relays will protect them.

8

Transformer protection

8.1 Introduction

In general, a transformer may be protected by fuses, overcurrent relays, differential relays and pressure relays, and can be monitored for incipient trouble with the help of winding temperature measurements, and chemical analysis of the gas above the insulating oil. Which of these will be used in a given instance depends upon several factors as discussed below.


Power Transformers

- **Transformer size.** Transformers with a capacity less than 2500 kVA are usually protected by fuses. With ratings between 2500 and 5000 kVA, the transformer may be protected with fuses, but instantaneous and time-delay overcurrent relays may be more desirable from the standpoint of sensitivity and coordination with protective relays on the high and low sides of the transformer. Between 5000 and 10 000 kVA an induction disc overcurrent relay connected in a differential configuration is usually applied. Above 10 MVA, a harmonic restraint, percentage differential relay is recommended. Pressure and temperature relays are also usually applied with this size of transformer.
- **Location and function.** If the transformer is an integral part of the bulk power system, it will probably require more sophisticated relays in terms of design and redundancy.
- **Voltage.** Generally, higher voltages demand more sophisticated and costly protective devices, due to the deleterious effect of a delayed fault clearing on the system performance, and the high cost of transformer repair.
- **Connection and design.** The protection schemes will vary considerably between autotransformers, and two- or three-winding transformers. The winding connection of a three-phase

8.3 Percentage differential protection

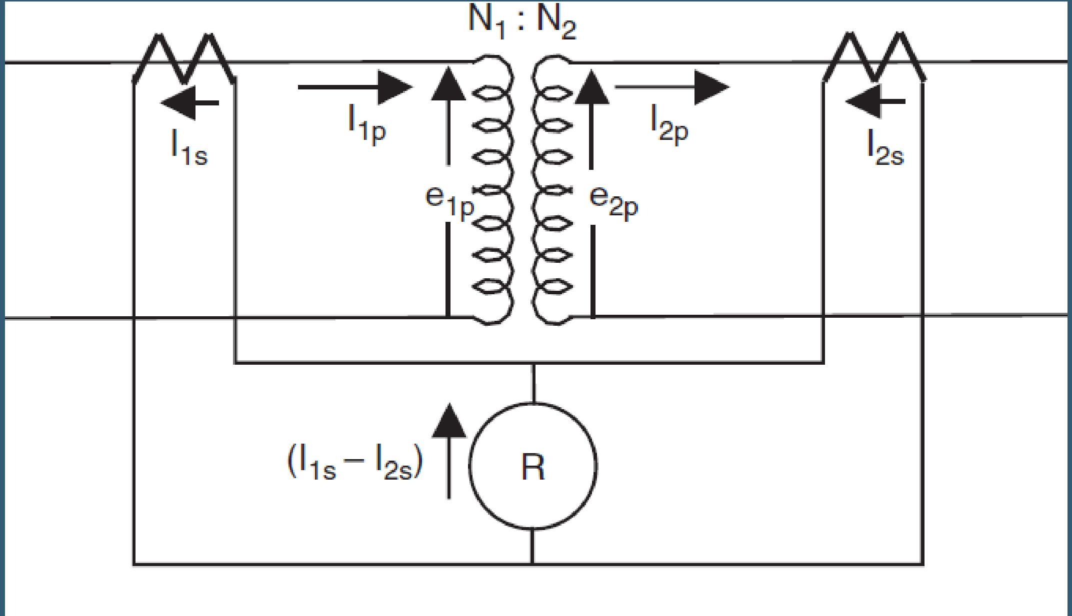


Figure 8.3 Differential relay connections

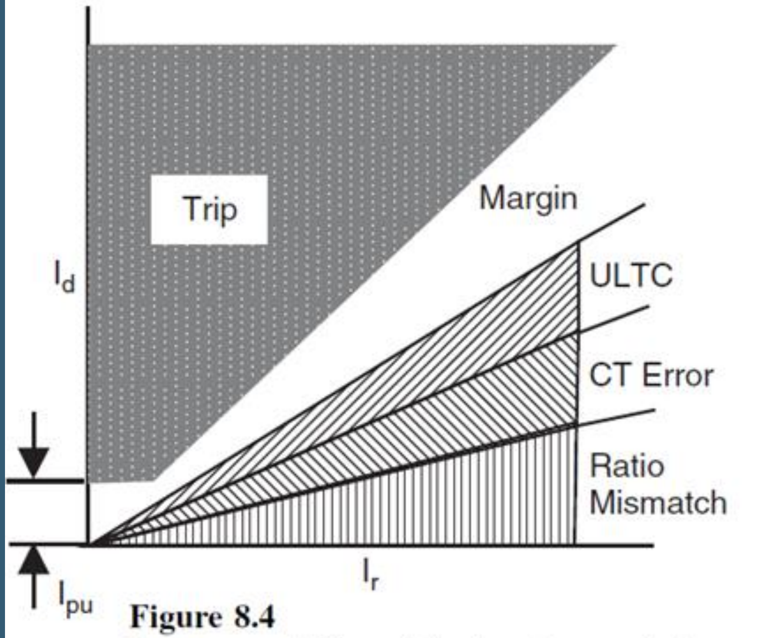


Figure 8.4
Percentage differential relay characteristic

$$I_\mathrm{d} = i_{1\mathrm{s}} - i_{2\mathrm{s}}$$

$$i_\mathrm{r} = \frac{i_{1\mathrm{s}} + i_{2\mathrm{s}}}{2}$$

$$i_\mathrm{d} \geq K\, i_\mathrm{r}$$

where K is the slope of the percentage differential characteristic. K is generally expressed as a percent value: typically 10, 20 and 40 %.

Example 8.3

A single-phase transformer is rated at 69/110 kV, 20 MVA. It is to be protected by a differential relay, with input taps of 3.0, 4.0, 4.5, 4.8, 4.9, 5.0, 5.1, 5.2, 5.5 A secondary. The transformer has an under load tap changer (ULTC) with a turns ratio of $-5\,\%$ to $+5\,\%$ in steps of $\frac{5}{8}\,\%$. Specify the CTs, the pickup setting and the percentage differential slope for the relay. The available slopes are 10, 20 and 40 %. What is the level of fault current, for an unloaded transformer, for which the differential relay will not operate?

The currents in the primary and the secondary for the rated load are 289.8 and 181.8 A respectively. We may select CT ratios of 300 : 5 and 200 : 5 for the two sides. These will produce $289.8 \times 5/300 = 4.83$ A, and $181.8 \times 5/200 = 4.54$ A in the two CT secondaries. In order to reduce a mismatch between these currents, we may use the relay tap of 4.8 for the CT on the primary side and the relay tap of 4.5 for the CT on the secondary side. This will give us a value of 4.83/4.8, or 1.0062×5 A, and 4.54/4.5, or 1.009×5 A in the relay coils. Thus, the differential current in the relay due to CT ratio mismatch would amount to $(1.009 - 1.006)$ pu, or about 0.3 %. The tap changer will change the main transformer ratio by 5 %, when it is in its extreme tap position. Thus, a total differential current of 5.3 % would result from these two causes. If no information on unequal CT errors is available, we must make appropriate assumptions, so that we may select a proper percentage slope for the relay characteristic. Assuming the CTs to be of the 10CXXX type, we may expect a maximum error of under 10 % in each of the CTs. It is therefore reasonable to assume that the errors in the two CTs will not differ from each other by more than 10 % under all fault conditions. This gives a net differential current of 15.3 % for the largest external fault, while the tap changer is at its farthest position. With about a 5 % margin of safety, we may therefore select a 20 % differential slope for the relay.

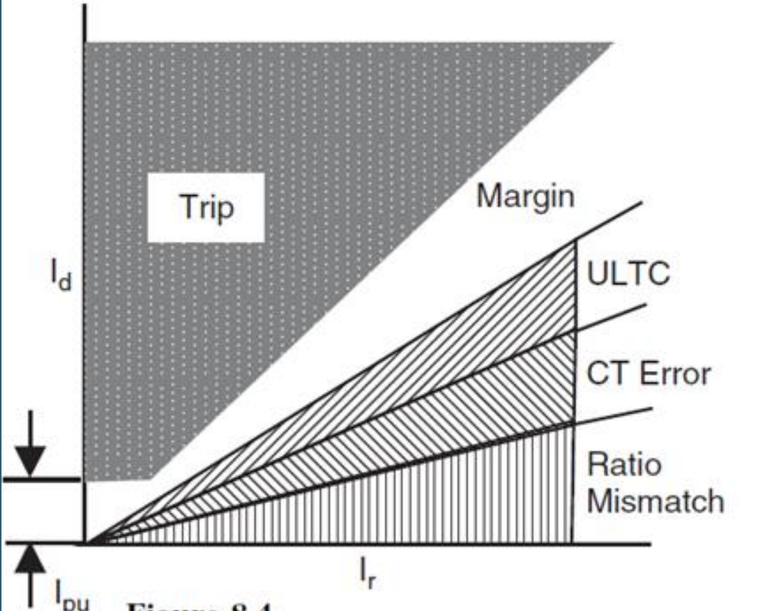
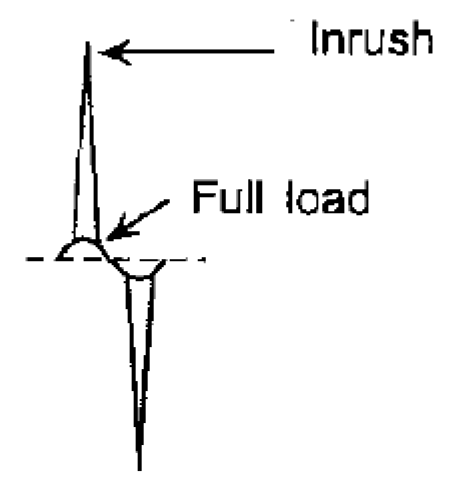
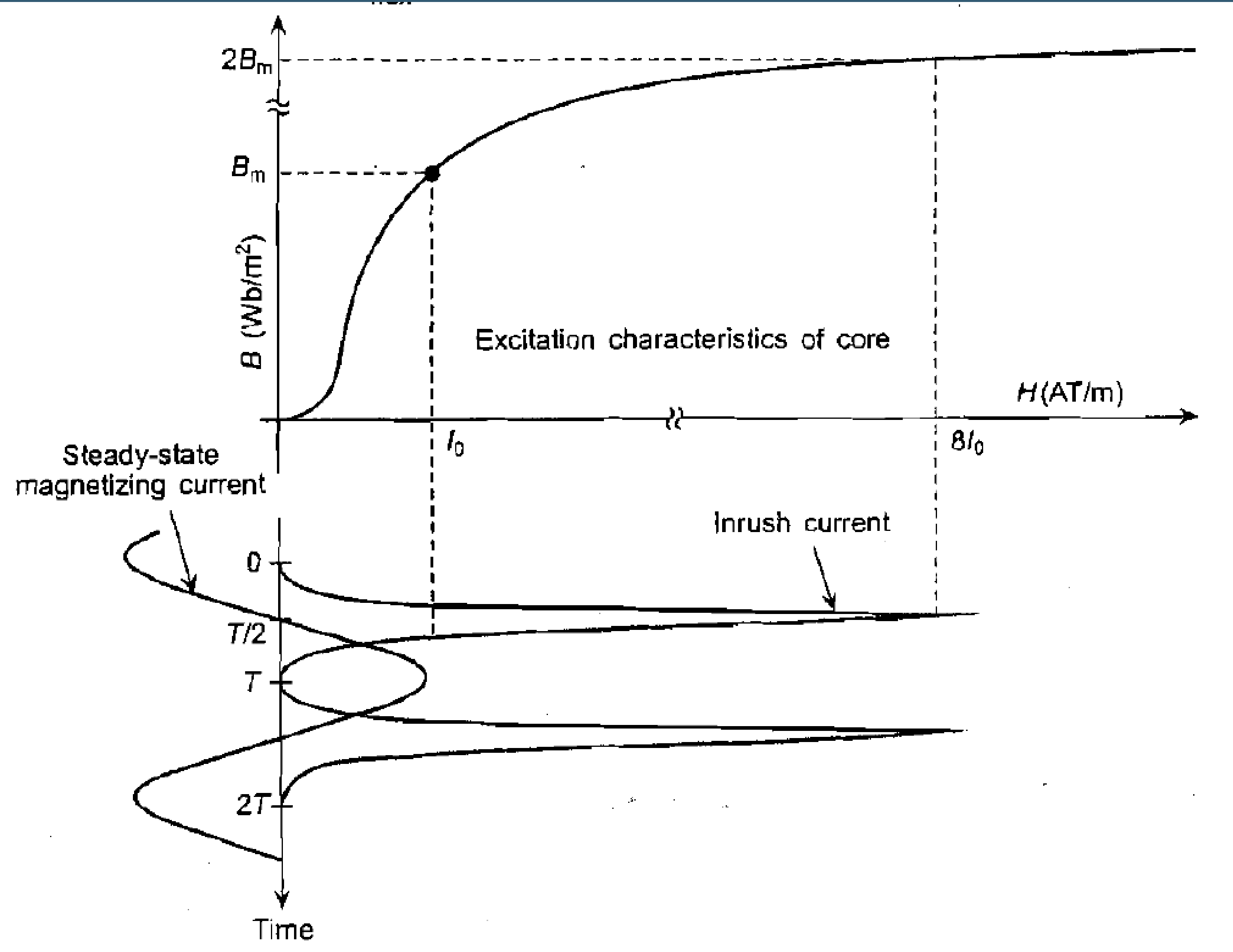


Figure 8.4
Percentage differential relay characteristic

The inrush phenomenon – See Paithankar, Chapter 4 for details





8.5 Supervised differential relays

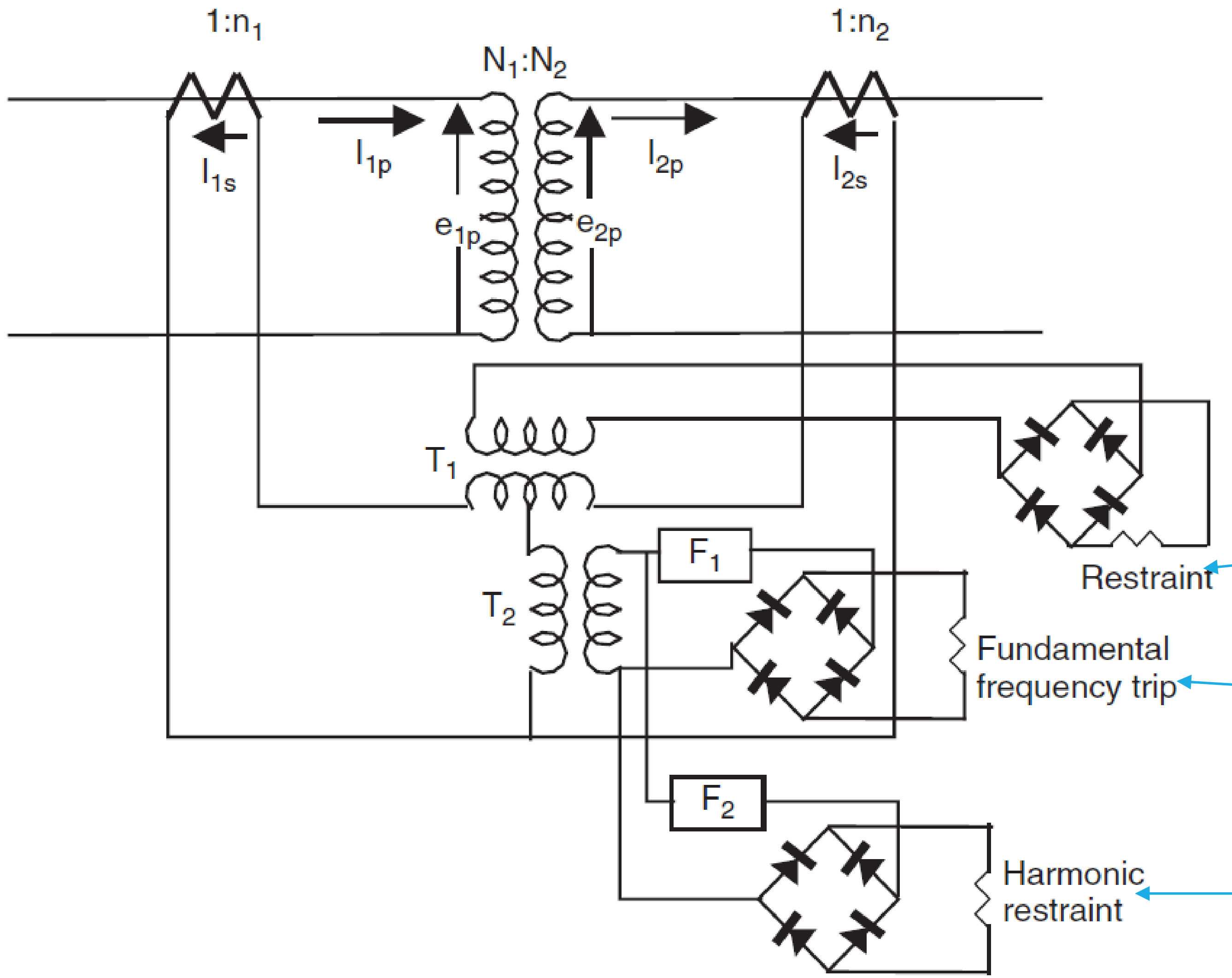
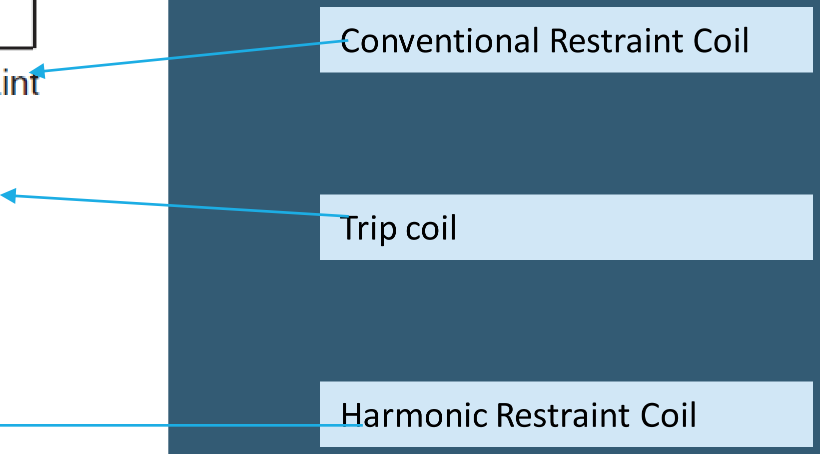


Figure 8.11 Harmonic restraint percentage differential relay.
F_1 is a pass filter and F_2 is a block filter for the fundamental frequency



8.6 Three-phase transformer protection

The current transformers on the wye side of the power transformer are connected in delta, and the current transformers on the delta side of the power transformer are connected in wye.

Example 8.4

Consider the three-phase transformer bank shown in Figure 8.12. The transformer is rated 500 MVA at 34.5(delta)/500(wye) kV.

Assume that the transformer is carrying normal load, and that the current in phase a on the wye side is the reference phasor. Thus, the three-phase currents on the wye side are

$$I_a = \frac{500 \times 10^6}{\sqrt{3} \times 500 \times 10^3} = (577.35 + j0.0)\text{ A}$$

577.3 /0

$$I_b = (-288.67 - j500.0)\text{ A}$$

$$I_c = (-288.67 + j500.0)\text{ A}$$

The currents on the delta side of the power transformer are

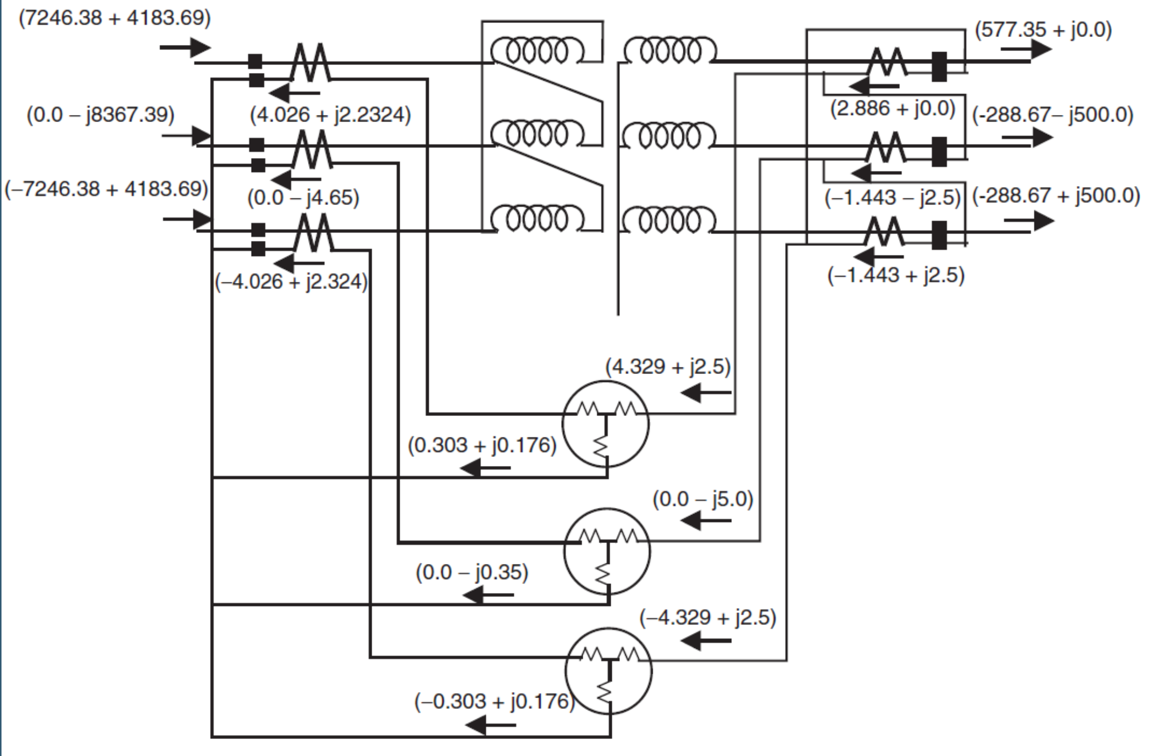
$$I_{ad} = \frac{500 \times 10^6}{\sqrt{3} \times 34.5 \times 10^3} \varepsilon^{j30°} = (7246.38 + j4183.69)\text{ A}$$

8367 /30

$$I_{bd} = (0.0 - j8367.39)\text{ A}$$

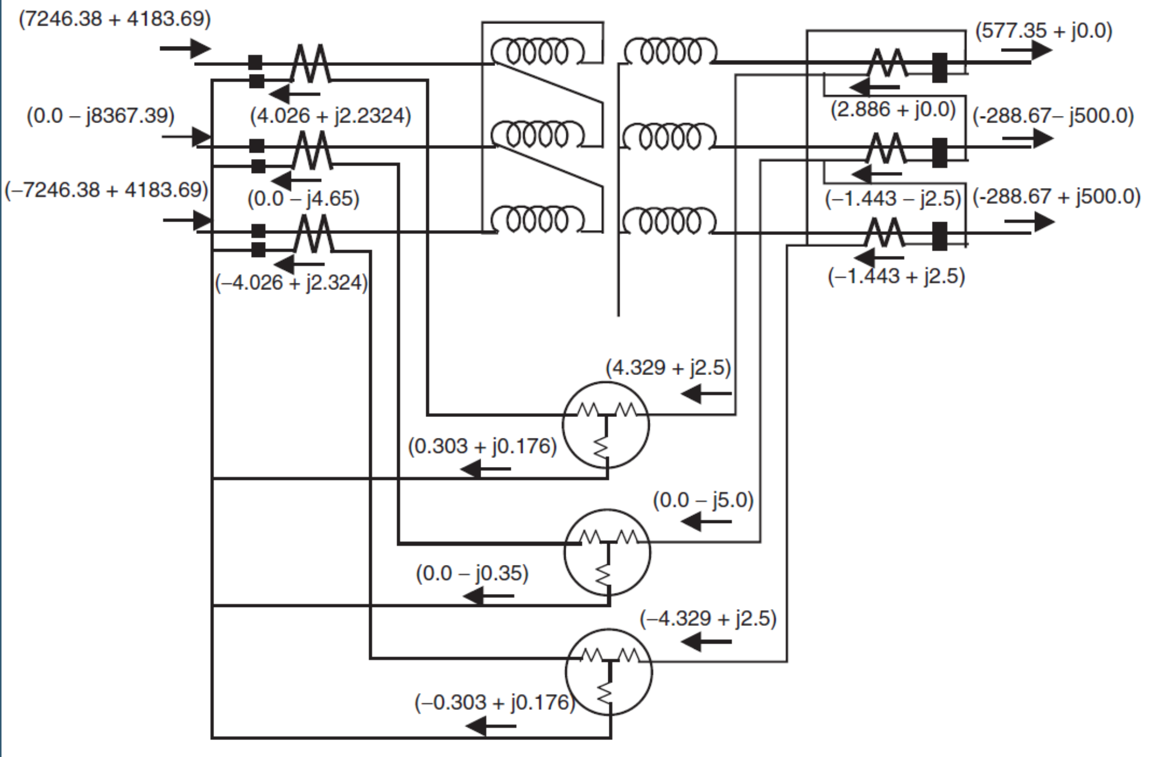
$$I_{cd} = (-7246.37 + j4183.69)\text{ A}$$

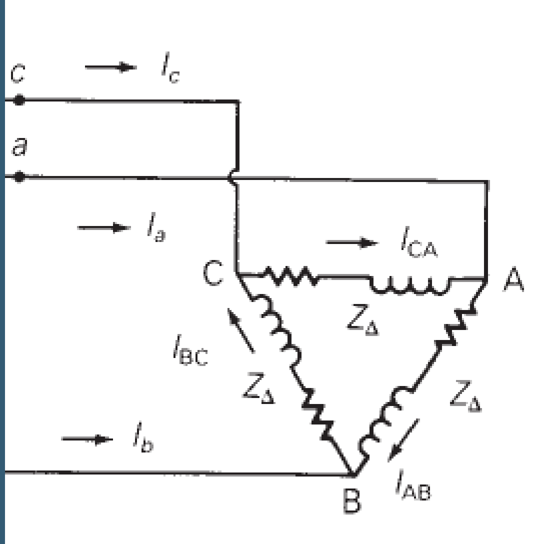
Note that the power transformer is connected with a leading delta. The CTs on the delta side of the power transformer are to be connected in wye. We may therefore select the CT ratio on this side to be such that the CT secondary current will be less than 5 A when the primary current is 8367.39 A. Select the CT ratio of 9000 : 5. This produces CT secondary currents on this side of (8367.39 × 5/9000) = 4.65 A. The three CT secondary current phasors are shown in Figure 8.12.



The CTs on the wye side of the power transformer are going to be connected in delta. Thus, the CT ratios must be such that the CT secondary winding currents will be close to $(4.65/\sqrt{3}) = 2.68$ A. This calls for a CT ratio of 577.35/2.68, or 1077 : 5. Selecting the nearest standard CT ratio (see Table 3.1) of 1000 : 5 produces CT secondary winding currents of magnitude $577.35 \times 5/1000 = 2.886$ A. This will produce a CT delta line current of magnitude $2.886 \times \sqrt{3} = 5$ A. Although this is not exactly equal to the line currents produced by CTs on the 34.5 kV side of the power transformer (4.65 A), this is the best that can be done with standard CT ratios. As in the case of single-phase transformers, the relay taps can be used to reduce this magnitude mismatch further.

The actual phasors of the CT secondary currents are shown in Figure 8.12. It should be noted that the CTs on the wye side of the power transformer are connected in such a manner that the currents in the relays are exactly in phase, and very small currents flow in the differential windings of the three relays during normal conditions. The currents are calculated with due attention given to the polarity markings on the CT windings.





$$I_a = \sqrt{3} I_{AB} \underline{/-30^\circ}$$

$$I_b = \sqrt{3} I_{BC} \underline{/-30^\circ}$$

$$I_c = \sqrt{3} I_{CA} \underline{/-30^\circ}$$