SECTION 15

POWER-SYSTEM PROTECTION

Thomas H. Ortmeyer
Clarkson University

Protective systems are designed to sense faults and initiate fault clearing in a timely manner while minimizing the affected area. Protective relays are used to sense the faults and initiate circuit breaker tripping. Alternatively, fuses are used on the distribution system to sense and clear faults.

Protective relays sense system current and voltage levels to determine both the presence and location of faults. Current transformers (CTs) and voltage transformers (VTs) are used to scale the system levels to levels suitable for the relays and measurement instruments. Voltage transformers are most commonly connected with wye secondaries, with 120Y/69 V being a standard secondary-voltage rating. They are selected through their voltage and volt-amp requirements. Current transformers carry both a continuous current rating and a burden rating. Their application is discussed in the next section.

Recently, digital protective relays have become available and are popular in many applications. These relays offer flexibility, self-checking, and ease of installation and often can provide additional functions over traditional electromechanical relays. Settings calculations for many of these relays are straightforward and are outlined in the relay's applications manual. In order to make these calculations, knowledge of peak-load current, minimum and maximum fault currents, and the CT and VT ratings is required.

This section provides a brief overview of some of the most common protective relaying applications. A much fuller discussion of these topics is available elsewhere, including Anderson (1999), Blackburn (1987), Elmore (1994), and IEEE Buff Book. Relay manufacturers commonly supply application information for their products as well. Finally, special situations can arise that will require additional or different protective measures than are discussed here.

CURRENT TRANSFORMER CONNECTION AND SIZING

Current transformers (CTs) commonly have a 5 A (continuous) secondary rating. Many current transformers are multiratio, with the user being able to select the CT turns ratio from among several available on a particular device. Current transformers are typically able to carry fault currents up to 20 times their rating for short periods of time. Their ability to do this depends on their loading being within their specified burden rating.

Example 15.1

A current transformer is specified as being 600 A:5 A class C200. Determine it's characteristics.

This designation is based on ANSI Std. C57.13-1978. 600 A is the continuous primary current rating, 5 A is the continuous secondary current rating, and the turns ratio is 600/5 = 120. C is the accuracy class, as defined in the standard. The number following the C, which in this case is 200, is the voltage that the CT will deliver to the rated burden impedance at 20 times rated current without exceeding 10 percent error. Therefore, the rated burden impedance is

$$Z_{\text{rated}} = \frac{\text{Voltage class}}{20 \cdot \text{Rated secondary current}} = \frac{200\ \text{V}}{20 \cdot 5\ \text{A}} = 2\ \Omega$$

This CT is able to deliver up to 100 A secondary current to load burdens of up to 2 Ω with less than 10 percent error. Note that the primary source of error is the saturation of the CT iron core and that 200 V will be approximately the knee voltage on the CT saturation curve. This implies that higher burden impedances can be driven by CTs which will not experience fault duties of 20 times rated current, for example.

A typical wye CT connection is shown in Fig. 15.1. The neutral points of the CTs are tied together, forming a residual point. Four wires, the three-phase leads and the residual, are taken to the relay and instrument location. The three-phase currents are fed to protective relays or meters, which are connected in series. After these, the phases are connected to form and tied back to the residual. Additional relays are often connected in the residual, as the current in this circuit is proportional to the sum of the phase currents and corresponds to the current that will eventually end up flowing through neutral or ground.

Example 15.2

The circuit of Fig. 15.1 has 600:5 class C100 CTs. The peak-load current is a balanced 475 A per phase.

1. Determine the Relay Currents for the Peak-Load Conditions.

The A phase CT secondary current is

$$I_A = \frac{475\text{A}}{120} = 3.96\ \text{A}\underline{/0^\circ}$$

Here, the A phase current is taken to be at 0°. The B and C phase currents are the same magnitude, shifted by 120°,

$$I_B = 3.96\ \text{A}\underline{/-120^\circ},\ I_C = 3.96\ \text{A}\underline{/120^\circ}$$

The residual current is

$$I_R = I_A + I_B + I_C = 3.96\ \text{A}\underline{/0^\circ} + 3.96\ \text{A}\underline{/-120^\circ} + 3.9.6\ \text{A}\underline{/120^\circ} = 0\ \text{A}$$

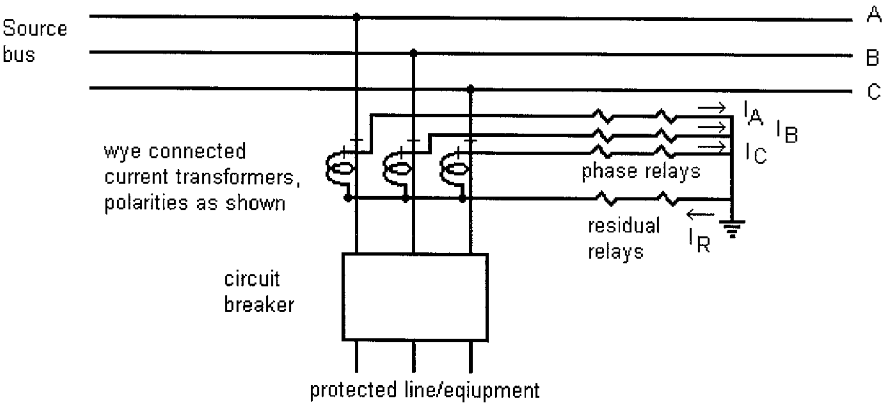

FIGURE 15.1 Typical setup for wye-connected CTs protecting a line or piece of equipment.

2. The circuit has an *A* phase to ground fault on the line, with fault current magnitude of 9000 A. Find the phase and residual relay currents. Again, assume that the *A* phase current is at 0°.

$$I_A = \frac{9000\text{ A}}{120} = 75\text{ A}\underline{/0^\circ}$$

$$I_B = 0\text{ A}$$

$$I_C = 0\text{ A}$$

$$I_R = I_A + I_B + I_C = 75\text{ A}\underline{/0^\circ} + 0\text{ A} + 0\text{ A} = 75\text{ A}\underline{/0^\circ}$$

The current path is therefore through the *A* phase lead and back through the residual lead.

3. The circuit has a two-phase fault with 5000 amps going out *B* phase and back in on *C* phase. Choose *B* phase current to be at 0°.

$$I_A = \frac{0\text{ A}}{120} = 0\text{ A}$$

$$I_B = \frac{5000\text{ A}\underline{/180^\circ}}{120} = 41.7\text{ A}\underline{/0^\circ}$$

$$I_C = \frac{5000\text{ A}\underline{/180^\circ}}{120} = 41.7\text{ A}\underline{/180^\circ} = -I_B$$

$$I_R = I_A + I_B + I_C = 0\text{ A} + 41.7\text{ A}\underline{/0^\circ} + 41.7\text{ A}\underline{/180^\circ} = 0\text{ A}$$

This current path involves the *B* and *C* phase leads, with no current in either the *A* phase lead or residual.

4. The circuit has a three-phase fault with 8000 A per phase.

$$I_A = \frac{8000\text{ A}\underline{/0^\circ}}{120} = 66.7\text{ A}\underline{/0^\circ}$$

$$I_B = \frac{8000\ \text{A}\angle -120^\circ}{120} = 66.7\ \text{A}\angle -120^\circ$$

$$I_C = \frac{8000\ \text{A}\angle 120^\circ}{120} = 66.7\ \text{A}\angle -120^\circ$$

$$I_R = I_A + I_B + I_C = 66.7\ \text{A}\angle 0^\circ + 66.7\ \text{A}\angle -120^\circ + 66.7\ \text{A}\angle 120^\circ = 0\ \text{A}$$

The phase currents sum to zero, so no current flows in the residual for this fault.

The path of current flow for these various situations must be considered in calculating the CT excitation voltage and subsequent saturation.

Example 15.3

For part 2, 3, and 4 of Example 15.2, calculate the CT voltage if the phase relay burden is 1.2 Ω, the residual relay burden is 1.8 Ω, the lead resistance is 0.4 Ω, and the CT resistance is 0.3 Ω. Neglect CT saturation in this calculation.

1. Single-Phase Fault

The A phase CT will have an excitation voltage of

$$\begin{aligned} V_{\text{ex}A} &= I_{A\text{sec}}(Z_{\text{CT}} + 2Z_{\text{lead}} + Z_{\text{phase}} + Z_{\text{residual}}) \\ &= 75\ \text{A}(0.3\ \Omega + 2 \cdot 0.4\ \Omega + 1.2\ \Omega + 1.8\ \Omega) \\ &= 307\ \text{V} \end{aligned}$$

The impedances are primarily resistive, and phase angle is often neglected in the voltage calculations. The impedances can be determined by tracing the path of the current through the CT secondary circuit.

2. Two-Phase Fault

$$\begin{aligned} V_{\text{ex}B} &= I_{B\text{sec}}(Z_{\text{CT}} + Z_{\text{lead}} + Z_{\text{phase}}) \\ &= 41.7\ \text{A}(0.3\ \Omega + 0.4\ \Omega + 1.2\ \Omega) \\ &= 79.2\ \text{V} \end{aligned}$$

The C phase CT will see a similar voltage. Note that the A phase CT will also see a significant voltage, although it is carrying no current.

3. Three-Phase Fault

$$\begin{aligned} V_{\text{ex}A} &= I_{A\text{sec}}(Z_{\text{CT}} + Z_{\text{lead}} + Z_{\text{phase}}) \\ &= 66.7\ \text{A}(0.3\ \Omega + 0.4\ \Omega + 1.2\ \Omega) \\ &= 126.7\ \text{V} \end{aligned}$$

The worst-case fault for this example is therefore the single-phase fault. It is clear that a CT with a saturation voltage of 200 V would experience substantial saturation for this fault. This saturation would cause a large reduction in the current delivered. In the other two cases, the CT remains unsaturated, so the CT will deliver the expected current at this voltage level.

Example 15.4

Multiratio Current Transformers. A current transformer has maximum load current of 650 A and maximum fault current of 10,500 A. The total burden impedance is 2.1 Ω. A

1200:5 class C200 multiratio CT is present. The available CT taps are 100, 200, 300, 400, 500, 600, 800, 900, 1000, and 1200. (These taps represent the primary current rating, with the secondary current rating being 5 A for all tap selections.)

The continuous primary current rating must be greater than 650 A. The continuous rating should also be greater than 5 percent of the maximum fault current—10,500 A/20 or 525 A. Therefore, 800, 900, 1000, and 1200 will satisfy these criteria. The other criteria involves avoiding saturation on the maximum fault. Note that the partial winding use of a CT reduces the saturation voltage in proportion the percentage of the total turns in use. Therefore, the 800:5 tap has 800/1200 = 67 percent of the turns in use. Estimating the full winding saturation voltage at 200 V, the saturation voltage for the 800 A tap is

$$V_{\text{knee}} = 0.67 \cdot 200 \text{ V} = 133 \text{ V}$$

Neglecting saturation, the worst-case voltage on the CT would be

$$V_e = \frac{I_{\text{fault}}}{\text{N}_{\text{CT}}} Z_{\text{burden}} = \frac{10{,}500 \text{ A}}{160} 2.1 \ \Omega = 138 \text{ V}$$

I_{fault} is the fault current flowing in the CT primary, and N_{CT} is the CT turns ratio in use. In this case, the excitation voltage is somewhat higher than the CT knee voltage, so a different tap should be considered. For the 1000:5 ratio setting,

$$V_{\text{knee}} = 0.833 \cdot 200 \text{ V} = 167 \text{ V}$$

and the expected maximum excitation voltage would be

$$V_e = \frac{I_{\text{fault}}}{N_{\text{CT}}} Z_{\text{burden}} = \frac{10{,}500 \text{ A}}{200} 2.1 \ \Omega = 110 \text{ V}$$

This voltage is significantly less than the CT knee voltage, so that the CT ratio of 1000:5 is a better choice than the 800:5 ratio in this application.

TIME OVERCURRENT PROTECTION OF RADIAL PRIMARY DISTRIBUTION SYSTEMS

Time overcurrent (TOC) protection is the common protection method used on radial distribution networks. Time overcurrent relay characteristics offer fast response at high current levels, with the response time increasing as fault current level declines. With careful coordination between devices, selective coordination is possible so that the fault is sensed and cleared by downstream devices before the upstream device responds to the fault. TOC relay characteristics also allow for selective coordination between fuse and relay and between fuses. In addition to these devices, automatic circuit reclosers are self-contained devices that can be pole-mounted and will sense and clear faults to isolate feeder segments.

Example 15.5

Figure 15.2 shows an example involving a pair of fuses where the downstream fuse protects the upstream fuse for a fault at the location shown. Fuse operation is characterized by the fuse element melting, arcing, and clearing the fault. Fuses will generally coordinate if the total clearing time of the protecting fuse is less than 75 percent of the minimum

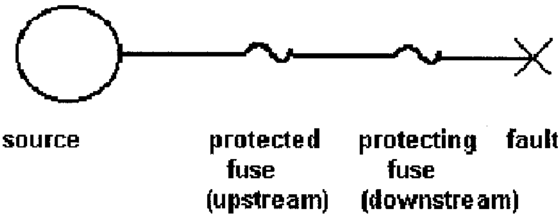

FIGURE 15.2 Protected and protecting fuse terminology.

melting time of the protected fuse for all currents up to the maximum fault current that the pair will experience. The maximum fault current is typically the bolted (zero fault impedance) fault just downstream of the protecting fuse. Figure 15.3 shows a 50-K (50-A continuous current rating, K fuse curve) fuse link protecting a 140 K fuse link for a maximum coordinating current of 5000 A. For either fuse, the lower boundary represents the minimum melting time of the fuse link, while the upper boundary represents the total clearing time of the fuse link. The curves are closest at 5000 A, and the gap between curves at this point represents the available coordinating margin. In this case, the total clearing time of the 50-K fuse link is about 80 percent of the minimum melting time of the 140-K link at 5000 A, so the margin is a bit too small to ensure coordination at 5000 A.

Time-current curves for specific devices are available from the device manufacturer. Coordination curves can be drawn by hand or on the computer using one of several software packages that are available on the market.

Example 15.6

Selection of Distribution Transformer Fuse. Transformer trf-1 is a three-phase, 900-kVA, 13.2-kV:480-V grounded wye-grounded wye transformer. Rated load current in the primary winding of the transformer is

$$I_{\text{rated}} = \frac{450\ \text{kVA}}{\sqrt{3}\cdot 13.2\ \text{kV}} = 20\ \text{A}$$

It can typically be expected that transformer inrush current on this bank will be 10 to 12 times rated current for 100 ms, with the first half-cycle of current being somewhat higher. Also, some duration of overload current can be expected due to cold load pickup. Allow 2 times rated current for 10 s due to this effect. The transformer fuse cannot operate for any of these events. On the other hand, the fuse must operate and clear the fault before transformer damage occurs during a fault on the transformer secondary. Many transformers are designed to conform to the damage points described in ANSI Std. C57.109. Figure 15.4 shows the time-current curve for these points. The figure also shows the melting and clearing curves of a 30-K fuse link. The fuse-link melting curve lies above all the load points, indicating it will not melt for these normal conditions. The fuse clearing curve lies below the transformer damage points, indicating that it will protect the transformer.

Note that the transformer fuse melting curve must also be above the transformer secondary circuit breaker total clearing curve. Also, the possibility of ferroresonance should be examined in distribution transformers with ungrounded primaries.

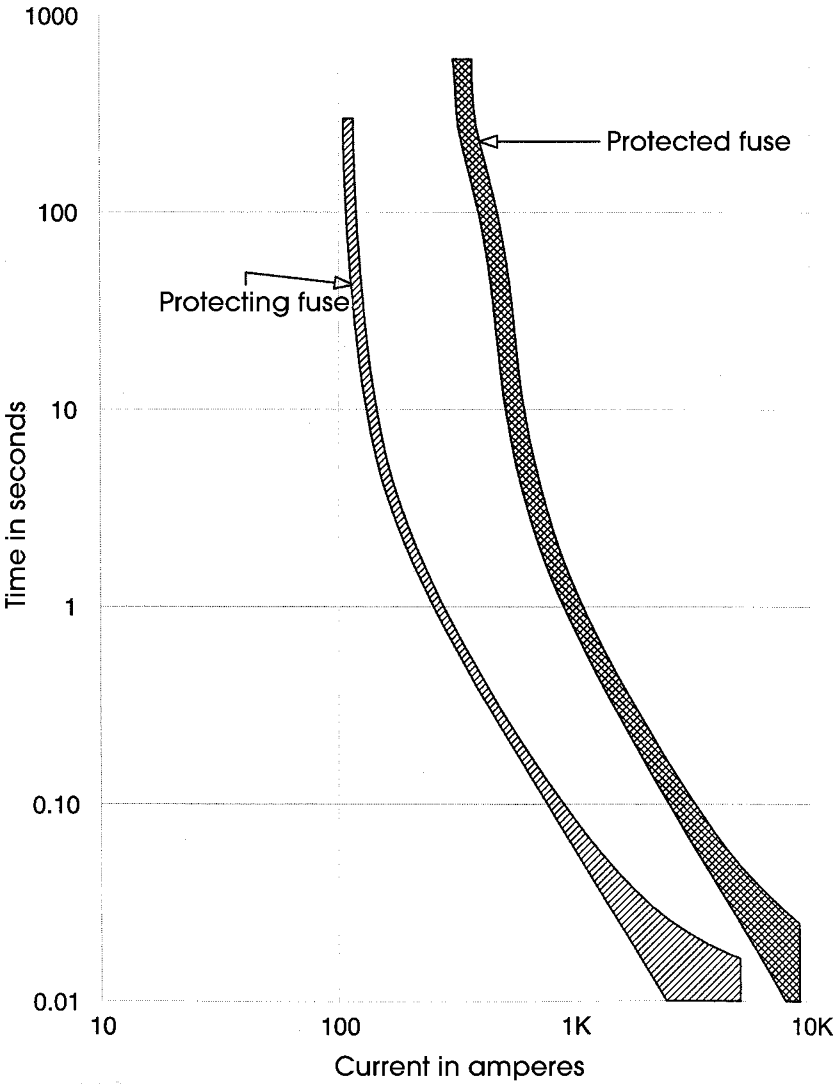

FIGURE 15.3 Time-current curve showing the coordination of a 50-K fuse link with a 140-K fuse line, for a maximum fault current of 5000 A.

Time overcurrent protection of primary radial distribution lines is accomplished in a similar fashion. The one-line diagram of a typical line is shown in Fig. 15.5. This line has a feeder-head circuit breaker that employs time overcurrent relays for sensing faults. It has a recloser located at the approximate midpoint of the line. It also has several sectionalizing fuses, which are intended to isolate feeder taps, most of which are single phase. Finally, the feeder feeds numerous distribution transformers, which are protected by fuses. There is no generation on this feeder, so that all load current and fault current flows from the source through the substation bus and out the feeder to the fault. Figure 15.6

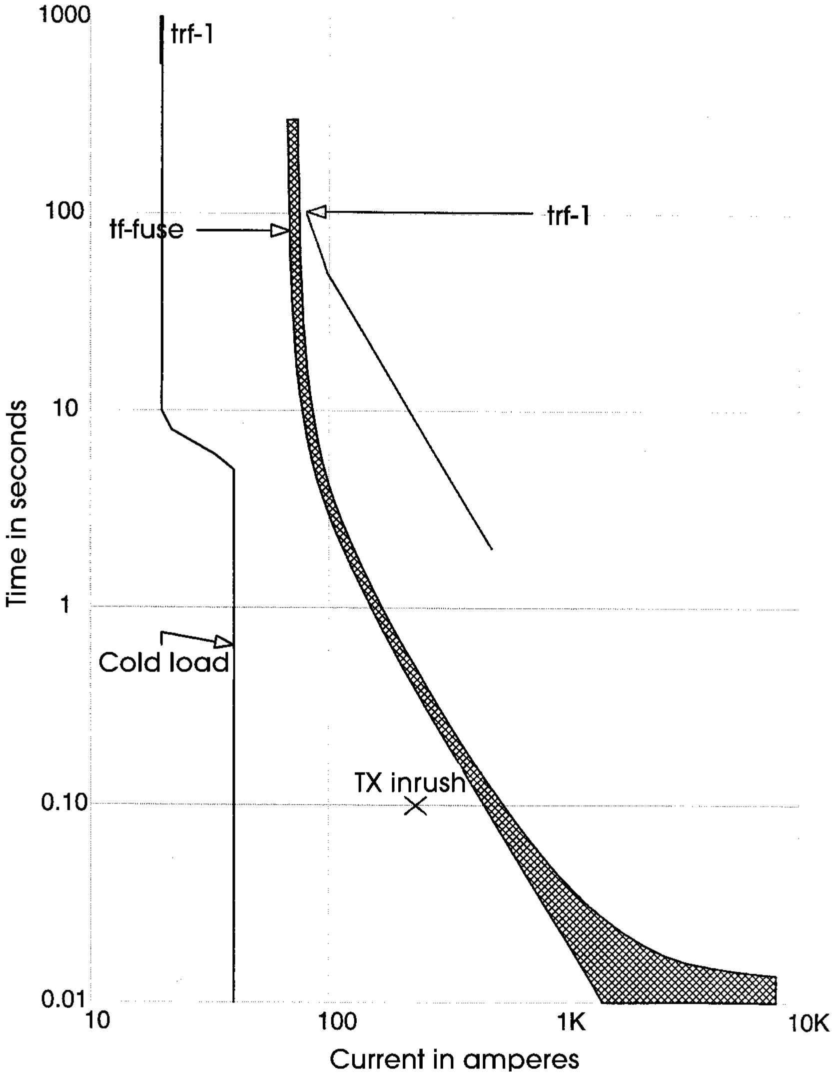

FIGURE 15.4 Time-current curve showing a 30-K fuse line protecting a 450-kVA transformer.

shows the same feeder with peak load currents noted. Figure 15.7 shows the same diagram with fault currents noted for faults at various locations on the diagram. It also shows the conductor size for the feeder.

The feeder protection must be determined to meet several objectives:

1. It must sense all faults on its section.
2. It must sense and clear faults before any equipment damage occurs.

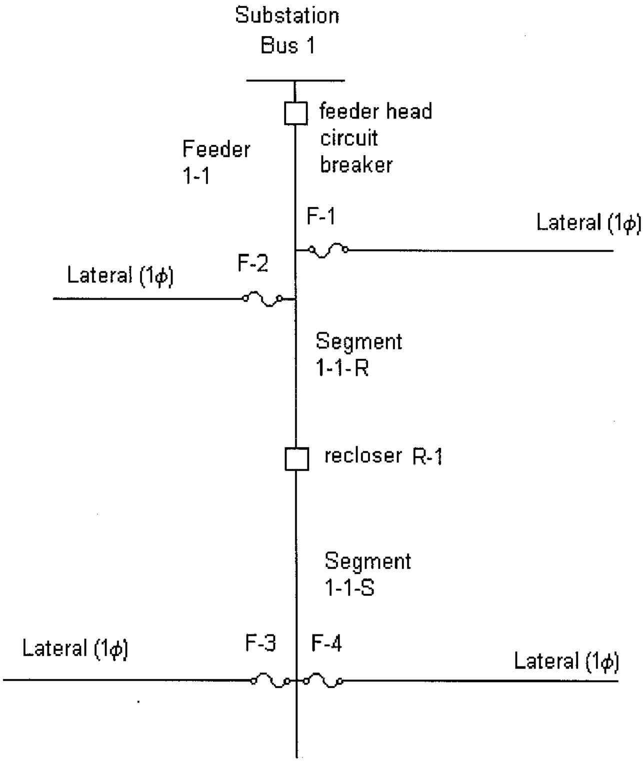

FIGURE 15.5 One-line diagram of a distribution feeder showing feeder-head circuit breaker (CB), line recloser, and sectionalizing fuses.

3. It must coordinate with upstream devices by sensing and clearing faults before the upstream device senses the fault.
4. It must avoid operating for load currents, including cold load pickup.

Finally, it must be noted that a large percentage of faults occurring on overhead lines are temporary. On temporary faults, it is possible to extinguish the arc by clearing the fault and then successfully return the line to service. This has obvious benefits for system reliability. Circuit breakers and reclosers are therefore commonly reclosed 1 to 3 times following a fault. Fuses, of course, must be replaced manually, resulting in an outage. In many cases, a fast trip is employed on a circuit breaker or recloser with the intention of having the fast trip operate and clear the fault prior to fuse melting. If the fault is temporary, the full circuit is returned to service following reclosing. If the fault is permanent, however, circuit reclosing will cause a restrike of the fault. Following one or two fast trips, the sensing device is switched to a slow trip, which allows the fuse to melt and clear before the slow-trip time elapses. This method, which is commonly referred to as fuse saving, allows service to be maintained to feeder taps for temporary faults on the tap and also allows service to be maintained on the main feeder for permanent faults on the tap.

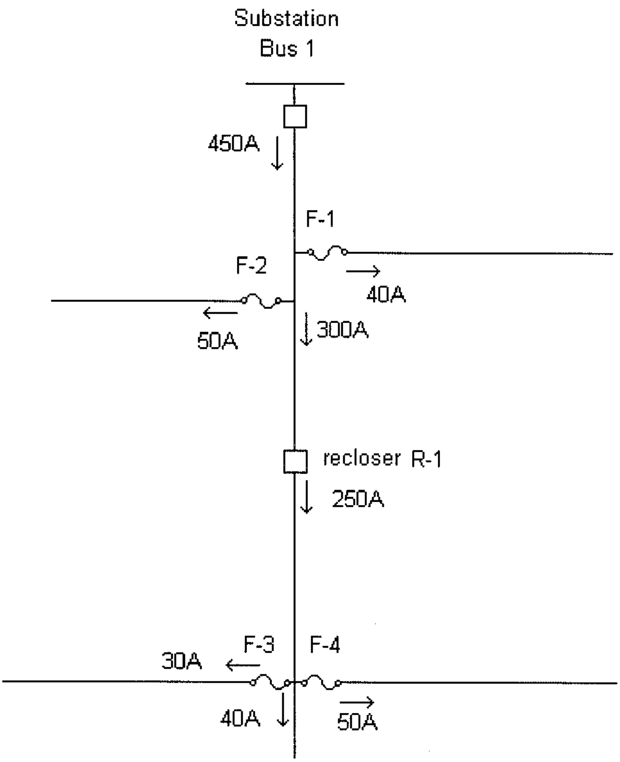

FIGURE 15.6 Feeder one-line diagram showing peak-load currents.

Example 15.7

Coordinate the Fig. 15.4 Feeder. Coordination of the various devices on the feeder is accomplished graphically through the use of time current curves (TCCs). This is generally an iterative process that is done graphically. The graphs can be drawn by hand or with one of several computer-aided engineering tools that are available. The following procedure outlines one approach to coordinating the feeder protection. Throughout this example, fuse and relay response curves and settings values are inserted into the discussion. These values are obtained from the fuse or relay manufacturer for their specific devices.

1. Determine the Feeder Head Relay Setting

The feeder head relay is fed by 600:5 current transformers, which sense the phase current in the circuit breaker. The relay setting requires a minimum pickup value, which sets the minimum fault current to which the relay will respond. The second setting is the time dial setting, which sets the time delay of the relay. A common starting point for setting the minimum pickup on primary distribution systems is twice maximum load current. Therefore, the initial setting for the circuit breaker relay should be approximately 1000 primary A. The current transformer rating is 600:5, so the TOC relay will see

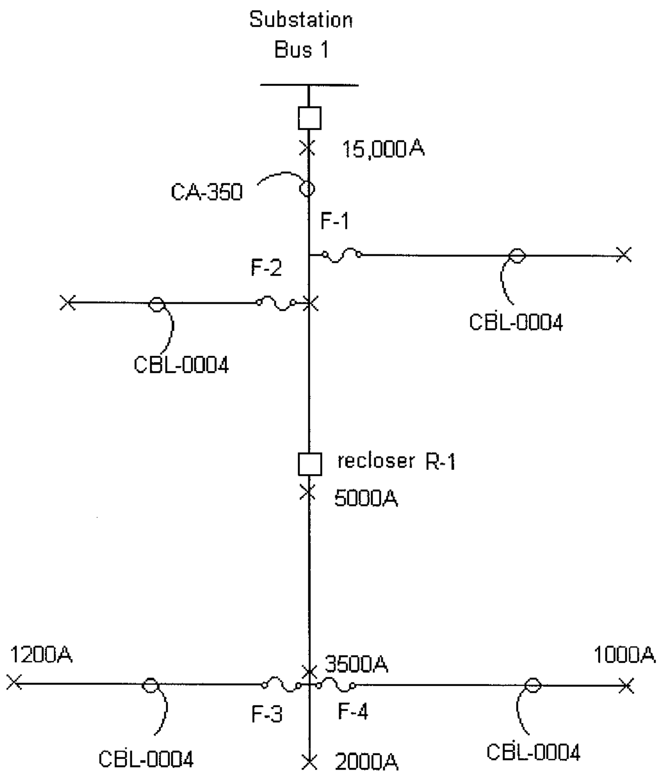

FIGURE 15.7 Feeder one-line diagram showing maximum fault currents at selected points and cable sizes.

$$I_{\text{relay}} = \frac{I_{\text{primary}}}{N_{\text{CT}}} = \frac{1000\text{ A}}{120} = 8.33\text{ A}$$

The closest available relay tap is 8.0 A, which corresponds to a primary setting of 960 A. The relay time lever is chosen so that the feeder circuit breaker will clear feeder faults before the substation transformer overload relay responds to the fault. Figure 15.8 shows the transformer overload relay curve. The total clearing time of the feeder circuit breaker is the relay response time plus the circuit breaker clearing time, plus auxiliary relay time if present. Therefore, the margin that must be maintained between the feeder relay curve and the bus relay curve equals the breaker time plus a reasonable margin. A typical margin is typically 0.25 to 0.3 s for electromechanical bus overload relays. Perhaps 0.10s of this margin allows for overtravel of electromechanical relays, which can be eliminated when solid-state or computer relays are used on the upstream devices (overtravel is the extra spin experienced by an electromechanical relay due to the momentum of the disk). Figure 15.8 shows the feeder-head phase relay selection with a suitable margin below the bus overload relay, up to the maximum fault current of 15,000 A. The figure also shows the damage curve for the main feeder cable, which is labeled CA-350. The feeder-head circuit breaker must clear the fault before cable damage occurs. In this case, the trans-

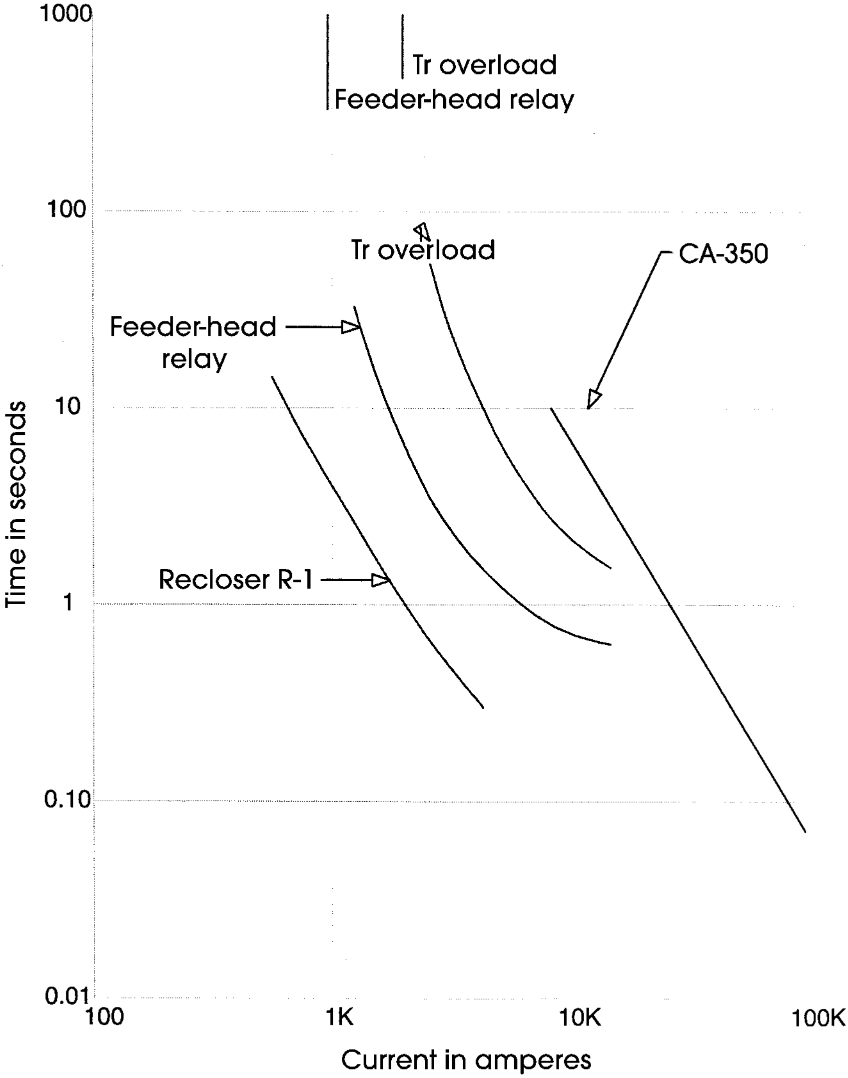

FIGURE 15.8 Time-current curve showing the coordination between the transformer overload relay, feeder-head relay, recloser slow trip, and line cable.

former overload relay will also protect the cable and will provide backup protection for the cable in the event of a failure of the feeder-head breaker.

2. Select the Recloser Minimum Pickup and Timing Curve

The recloser must sense and clear downstream faults before the feeder head relay senses the fault. The margin between the recloser clearing time and the feeder head relay sensing time is dependent on the recloser switching sequence and the type of feeder head relay. With electromechanical relays at the feeder head, the resetting time of the disk is important—during high current faults downstream from the recloser, the feeder head relay will respond with its disk traveling toward the trip position. When the recloser clears the fault, the disk on the feeder head relay will come to a stop and then reverse direction, going back toward the reset position. If the recloser closes back in on the fault before the feeder head relay resets, additional margin must be allowed between the recloser clearing time and feeder-head response curves.

Computer-based relays can be programmed to reset instantly and so are not subject to this increased margin. In a common situation, with electromechanical overcurrent relays, one fast trip on the recloser followed by two slow trips, and a 2-s delay to reclose, it has been found that coordination can be achieved by setting the recloser slow-trip clearing time to be less than 50 percent of the feeder-head-relay response time.

In this example, the peak-load current at recloser R1 is 275 A. A recloser minimum pickup setting of 560 A is therefore reasonable. The recloser would typically come with a selection of curves, which would be chosen to meet the margin requirement with the feeder head relay. Note that this margin is needed only up to a level of 5000 A, as the fault current will never exceed this value for faults beyond the recloser. This level of current marks the upper bound of the coordinating interval for this recloser-relay pair.

3. Recloser-Fuse Coordination

Any fuse downstream from the relay or recloser must melt and clear the fault before the relay or recloser senses the fault. A typical coordinating rule is that the total clearing time of the fuse must be less than 75 percent of the sensing time of the recloser or relay. The figure shows a variety of fuse curves sketched on top of the relay and recloser curves. Also shown on these curves is the largest current at which several of these pairs coordinate.

4. Fuse-Fuse Coordination

Downstream fuses must protect upstream fuses. The coordinating rule is similar to that in **(3):** The total clearing time of the downstream fuse must be less than 75 percent of the minimum melting time of the upstream fuse for coordination.

5. Fast Trip Coordination

Where it is desired to implement fuse saving through the use of a fast trip of a recloser or relay-circuit breaker, the coordinating rule is that the fast trip clearing time must be less than 75 percent of the minimum melting time of the fuse. This situation is shown in Fig. 15.9.

Items 1–5 must generally be repeated several times to achieve overall coordination on the feeder. The distribution transformer fuses place a lower bound on the coordinating curves, while the substation bus overload relays (or substation transformer overload relays) place an upper bound on these curves. Additionally, fault clearing curves must be below cable damage curves. Depending on the line configuration and loading, it is sometimes not possible to achieve coordination over the full range of coordinating intervals, which can result in two devices responding to a single fault. The design should eliminate or minimize this lack of coordination.

The preceding items discuss the response of the fuses and phase relays on the feeder. A similar procedure should be followed for the residual relay settings on the recloser and feeder-head circuit breaker. As the balanced load current does not flow through the residual relay, this relay can be set more sensitively than the phase relays. This is desirable in order to sense the low current faults that can result from one of the phases going to ground through a high fault impedance. Fuses, of course, do experience the full load current, so it is difficult to coordinate fuses with residual relays, and these relays are often set with relatively slow response times at the higher current levels. The minimum pickup of

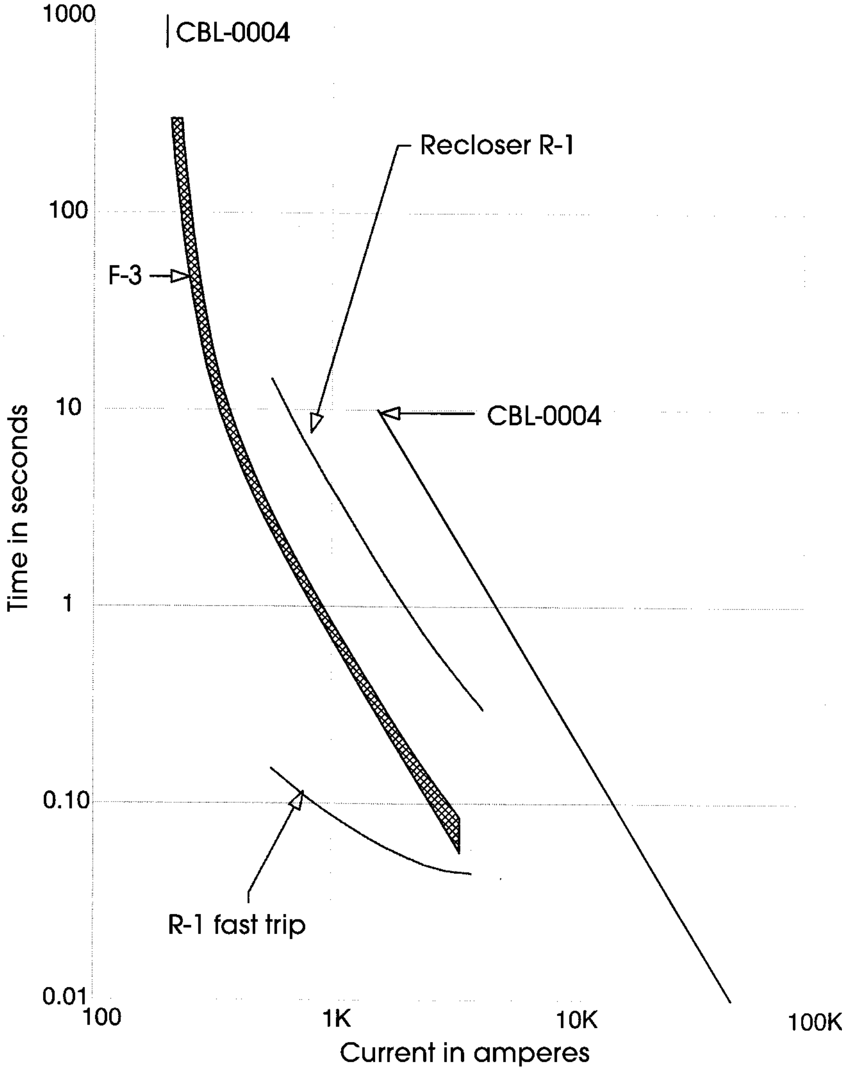

FIGURE 15.9 Time-current curve showing the coordination of the recloser fast and slow trips with sectionalizing fuse F-3.

residual elements must be above the level the relay will experience due to load imbalance, including the imbalance that is caused by the operation of a downstream fuse. A residual relay setting of approximately half of the phase load current level is reasonable in many cases. Residual relays will respond to faults that the phase relays do not sense, at the expense of some loss of selectivity. Nonetheless, there is some small but finite probability for the occurrence of high impedance faults that residual relays cannot detect. Specialized fault-detection relays for these events are under investigation.

The coordination of low-voltage distribution systems is accomplished in similar fashion. A brief consideration of low-voltage distribution is included in Section 5.

DIFFERENTIAL PROTECTION

Differential protection is applied on busses, generators, transformers, and large motors. Specialized relays exist for each of these applications, and their settings are described in the manufacturer's literature. Differential relays do require careful selection of current transformers. The full winding should be used when multiratio CTs are used in differential schemes, and other relays and meters should be fed from different CT circuits. Bus, generator, and large-motor differential schemes require matched sets of current transformers (with the same ratio and saturation characteristics) with suitable characteristics, while transformer differential protection requires CTs with limited mismatch.

Differential schemes are sometimes implemented on distribution busses with standard time overcurrent relays. An example of a single-phase differential scheme is shown in Fig. 15.10. With the current transformers connected as shown, the relay will see no current when the bus is intact (and with no CT error), as illustrated in Fig. 15.10*a* for a fault just outside the bus. During a bus fault, however, the relay will see the fault current divided by the CT ratio, as illustrated in Fig. 15.10*b*. The differential relay will see current on an external fault if one or more of the CTs saturate. In order to successfully

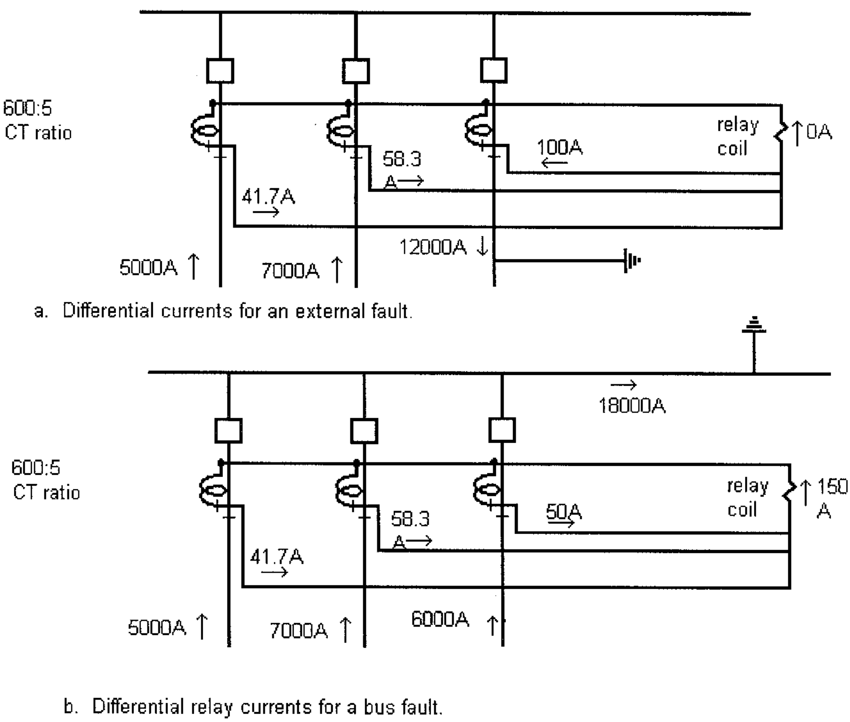

FIGURE 15.10 Example of a single-phase differential relay scheme.

implement this differential scheme, the saturation of the current transformers must not operate the relay for the maximum external fault. AC saturation of the CT will be avoided if the CT excitation voltage remains below the knee voltage of the CT. For the CT nearest the fault (and most subject to saturation), this voltage is

$$V_{\mathrm{CT}} = (I_{\mathrm{f}}/N_{\mathrm{CT}})(\mathrm{R}_{\mathrm{lead}} K_p + R_{\mathrm{CT}})$$

where

V_{CT} = the CT excitation voltage
I_{f} = the current in the primary of the CT nearest the fault
N_{CT} = the current transformer ratio in use
R_{lead} = the one-way lead resistance
K_p = 2
R_{CT} = the current transformer resistance

This scheme can be adopted to three-phase systems using wye-connected CTs. In this case, K_p is 1 for three-phase faults, and 2 for single-phase–to–ground faults.

If the excitation voltage of this CT is less than the CT knee voltage, the CT error will be no more than 10 percent. Assume no error in the other CTs. The relay current will be equal to the error current—in other words, 10 percent of the current that would be delivered with no saturation. In this example, the CT nearest the fault would ideally deliver 100 A. With 10 percent error, this current is reduced to 90 A, so 10 A will flow in the relay coil. Select a relay setting of 10 A.

The sensitivity of the differential scheme will be the relay set current times the CT ratio—10 A · 120 = 1200 A. Determine if this setting will sense the minimum bus fault. The minimum bus fault will occur when the bus is fed only by the weakest system and the fault has some resistance. In this example, the weakest system supplies 5000 A to a bolted fault. If only this breaker is closed and fault resistance reduces the fault by 75 percent, 1250 A would be the minimum expected fault current.

Select the relay time delay to avoid relay misoperation on dc saturation of the CT. Typically, this might be a two- or three-time dial setting with an inverse time characteristic, for a distribution bus with no local generation. (Note: The sensitivity of this scheme is marginal. Relays designed specifically for differential operation will offer substantial improvements in sensitivity for little additional cost. Also, the sensitivity can be improved with this scheme if the CT error is significantly less than 10 percent.)

STEP DISTANCE PROTECTION

Many transmission and subtransmission lines are protected with distance relays. These relays sense local voltage and current and calculate the effective impedance at that point. When the protected line becomes faulted, the effective impedance becomes the impedance from that point to the fault. A typical ohm distance characteristic is shown in Fig. 15.11. The maximum torque angle is set to be near the angle of the line impedance, to provide highest sensitivity for V/I ratios at that angle. The relay is inherently directional and will not sense reverse faults, which would appear in the third quadrant in Fig. 15.11. Also, the relay is less sensitive to load currents, which would be within 20 or 30° of the real axis in either direction. These desirable characteristics make distance protection popular. Distance protection is available for both phase and ground faults.

Step distance protection combines instantaneous and time delay tripping. Zone 1 is an underreaching element—any fault within Zone 1 is known to be on the protected line. When Zone 1 operates, the line is tripped instantaneously. However, Zone 1 will not oper-

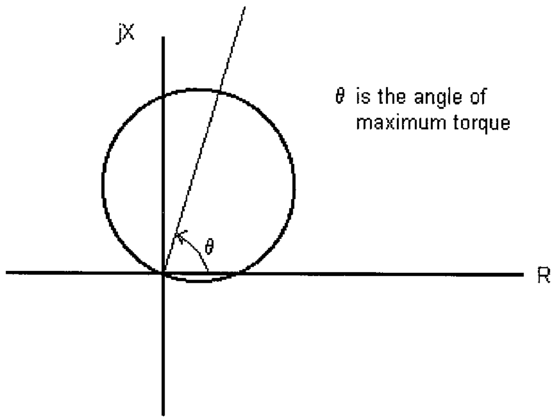

FIGURE 15.11 Distance relay ohm characteristic. Apparent impedances inside the circle will cause relay operation.

ate for all line faults. Zone 2 is an overreaching relay—it is set so that operation is guaranteed if the fault is on the line. Zone 2, however, will operate for some external faults. Selectivity is maintained by delaying Zone 2 tripping so that external faults are cleared by downstream devices—bus differential relays for a fault on the next bus, or Zone 1 relays on the next line. The Zone 2 time delay should be set for the auxiliary relay time + circuit breaker time + margin. A margin of 0.1–0.15 s is considered adequate, so that the Zone 2 delay may be 0.25 seconds for a 6-cycle circuit breaker.

Example 15.8

Figure 15.12 shows a typical example. We will consider the settings for line *PQ* at bus *P*. The impedance angle for all lines is 75°. The line length is 80 Ω. The distance relay at bus *P* is fed by current transformers rated at 2000 A:5 A and voltage transformers rated at 345 kV/200 kV Y:120 V/69 V Y. Set Zone 1 for 85 percent of this value (85–90 percent settings are typical for phase distance, slightly lower for ground distance):

$$
\begin{aligned}
\text{Zone 1 setting} &= 0.85 \cdot 80\ \Omega = 68\ \Omega\text{, primary ohm setting} \\
\text{CT ratio} &= 2000/5 = 400 \\
\text{VT ratio} &= 200{,}000/69 = 2900 \\
\text{Relay setting} &= \text{primary setting } (\Omega) \cdot \text{CT ratio/VT ratio} \\
&= 68\ \Omega \cdot (400)/(2900) \\
&= 9.38 \text{ relay ohms}
\end{aligned}
$$

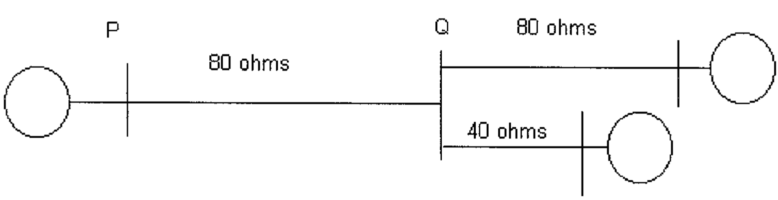

FIGURE 15.12 Example of step-distance relay setting.

$$\begin{aligned}\text{Zone 2 setting} &= \text{line length} \cdot 115 \text{ percent (minimum)}\\ &= \text{line length} + 0.5 \cdot \text{length of shortest next adjacent line (preferred)}\end{aligned}$$

The two next adjacent lines are 40 and 80 Ω, respectively. The shortest of these is 40 Ω. Half of that is 20 Ω. The setting 80 + 20 Ω = 100 Ω is greater than the minimum setting of 92 Ω (which guarantees seeing the entire line).

The relay setting is then

$$\begin{aligned}\text{Zone 2 setting} &= 100\ \Omega \text{ (primary)}\\ &= 100 \cdot 400/2900\\ &= 13.8 \text{ relay ohms}\end{aligned}$$

It must be noted that when the preferred setting is less than the minimum, the minimum must be selected. This means, however, that Zone 2 of the protected line is capable of reaching beyond Zone 1 of the short next line, so the time delay must be increased to avoid miscoordination.

Some schemes include a Zone 3 element for additional backup. Also, all bulk transmission lines include communications between line ends to provide instantaneous tripping for faults located at any point on the line.

Infeed Effect

The infeed effect shortens the reach of distance relays for relays reaching beyond a junction point. Infeed effect is illustrated in Fig. 15.13.

The apparent impedance to a distance relay at bus P is

$$Z_P = \frac{V_P}{I_P}$$

The bus voltage at P for a fault at F is

$$V_P = Z_{PQ}I_P + Z_{QF}(I_P + I_R)$$

The impedance sensed by the relay is then

$$Z_P = \frac{V_p}{I_P} = Z_{PQ} + Z_{QF}\left(1 + \frac{I_R}{I_P}\right)$$

The fault at F therefore appears to be further away than it actually is. On two terminal lines, this effect is not particularly important. On three terminal lines, however, the infeed effect must be fully considered to ensure complete coverage of the line under all conditions.

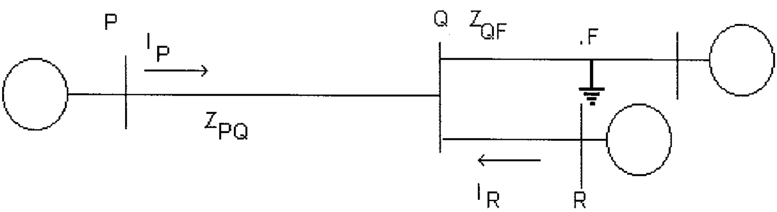

FIGURE 15.13 Example of infeed effect.

SMALL MOTOR PROTECTION

Induction motors can be damaged by a number of events, including short circuits, overloads, voltage unbalance, undervoltage, and locked rotor conditions. Small motors (up to several hundred horsepower) are commonly protected by a combination of fast protection for faults and slower protection for the other situations. The lower current protection must protect the motor from thermal damage while allowing the high currents drawn by the normal starting transient. This protection is generally provided by a combination of motor starter with overload sensing and fuses or circuit breaker. It also must be recognized that motor starters have limited current-clearing capability and must be protected from fault currents above their interrupting rating.

As motor size increases, it becomes impossible to protect against locked rotor conditions and unbalance through the sensing of stator phase current magnitude, and additional protection functions are needed. Computer-based relays are available for these situations, and the setting of these relays is relatively straightforward.

Example 15.9

Provide protection for the 100-hp induction motor shown in the one-line diagram of Fig. 15.14. System data:

Utility source: 13.2 kV, 80 MVA three-phase short-circuit capability.

Transformer XF2: 500 kVA, 13.2 kV:480 V delta-grounded wye.

Motor: 100 hp, 480 V, 0.85 pf, 85 percent efficient. Starting requires up to 5.9 · rated current for up to 8 s. Motor locked rotor thermal capability is 20 s.

1. Calculate Rated Motor Current

$$I_{\text{rated}} = \left(\frac{\text{motor horsepower} \cdot (746\text{w/hp}}{\text{power factor} \cdot \text{efficiency}}\right) \cdot \frac{1}{\sqrt{3} \cdot V_{\text{rated}}}$$

$$= \left(\frac{100 \cdot 746}{0.85 \cdot 0.85}\right) \cdot \frac{1}{\sqrt{3} \cdot 480}$$

$$= 124 \text{ A}$$

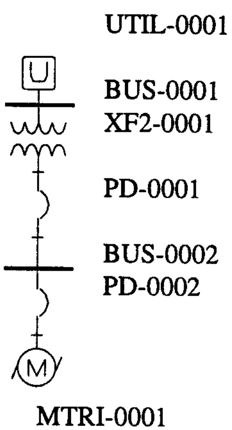

FIGURE 15.14 One-line diagram for small motor protection.

2. Calculate the Motor Starting/Running Curve and the Locked Rotor Point

See plot on Fig. 15.15.

3. Determine Motor Protection Characteristic

The minimum pickup must be between 100 and 125 percent of the motor rated current. The delayed trip must be above the starting/running curve but below the locked rotor thermal limit. A low-voltage circuit breaker was selected with both thermal and magnetic trips, and a thermal pickup setting of 125 A, with the magnetic trip set at 6.75 times that value. The plot PD-0001 shows this characteristic.

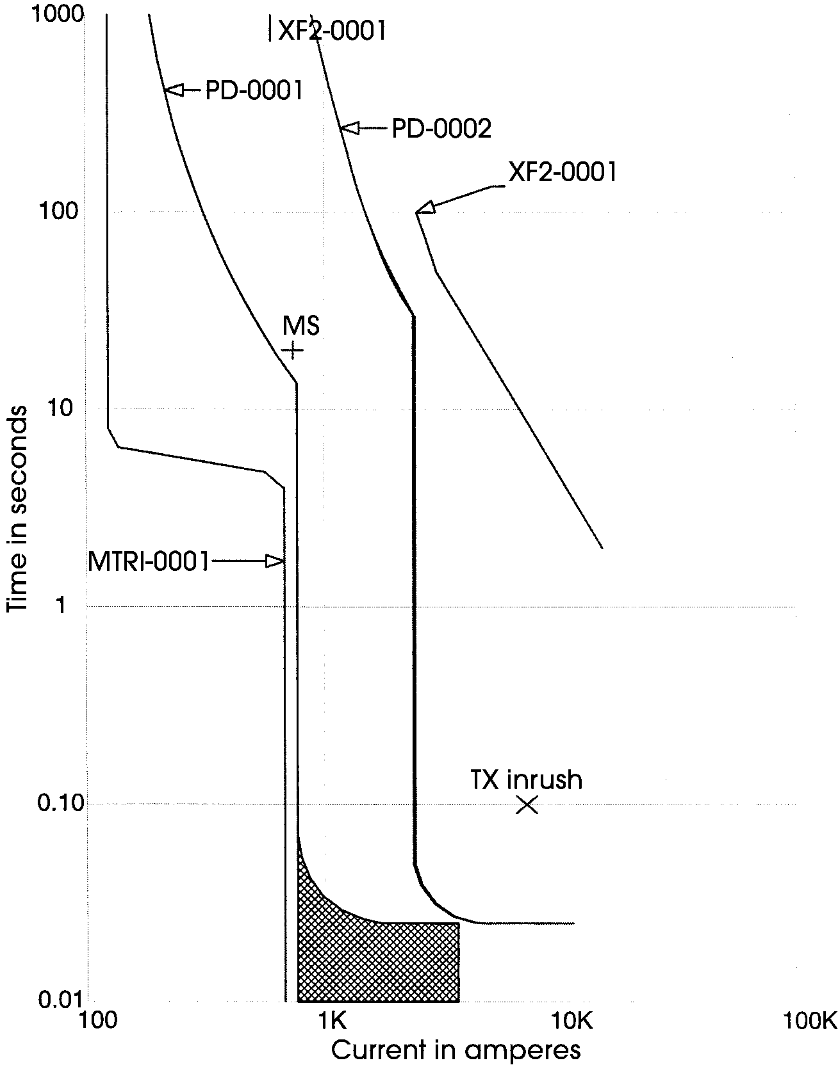

FIGURE 15.15 Time-current curve showing the coordination between motor MTRI-0001, motor protection PD-0001, transformer PD-0002, and the transformer damage characteristic.

4.

The motor protection must be faster than the transformer low-side circuit breaker, which in turn must protect the transformer from damage. The circuit-breaker characteristic is labeled PD-0002, while the curve XF-0001 shows the transformer damage characteristic.

Figure 15.16 shows similar protection provided by a motor starter with thermal overloads and fuse. The fuse in this case must protect the motor starter by interrupting currents above the starter clearing capability.

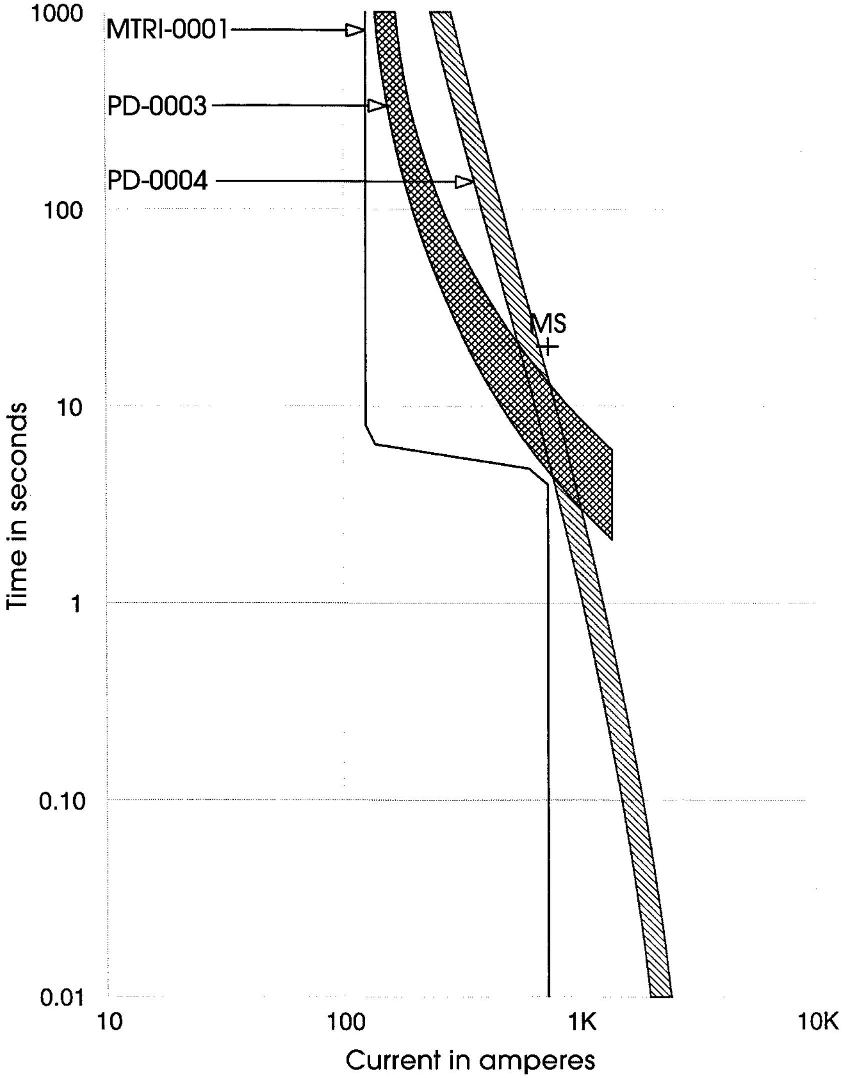

FIGURE 15.16 Time-current curve showing motor characteristics, contactor/thermal overload characteristic PD-0003, and fuse curve PD-0004.

SUMMARY

This chapter has described current and voltage transformer selection, and several common protection applications. Many protective functions exist that are not described in this chapter. Several excellent references are listed in the bibliography.

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