PDHonline Course E405 (6 PDH)

Overcurrent Protection for Electric Utility Systems

Instructor: Lee Layton, PE

2020

PDH Online | PDH Center

5272 Meadow Estates Drive
Fairfax, VA 22030-6658
Phone: 703-988-0088
www.PDHonline.com

An Approved Continuing Education Provider

Overcurrent Protection for Electric Utility Systems

Lee Layton, P.E

Table of Contents

Section **Page**

This course is based on the a bulletin Design Guide for Sectionalizing Distribution Lines developed by the Rural Utilities Service, a division of the United States Department of Agriculture.

Introduction

This course is an overview of how sectionalizing and protection studies are performed on electric distribution systems. It is not intended to provide a complete and exhaustive discussion of the subject, but rather to present the reader with helpful information and examples that will typically be encountered.

Within the arena of sectionalizing, there are many aspects of the subject that are established, quantifiable, and part of national standards. Included in this body of information are specific time-current characteristics of fuses and relays, the methods of calculations for available short-circuit current, and the standard damage points for distribution transformers. There are also many aspects of sectionalizing that are more subjective, debatable, and influenced by experience. These include “fuse save” versus “fuse blow,” coordination margins, and transformer protection practices. This reflects the idea that system protection is partly science and partly art.

This course concentrates on the “science” side of the subject and offers some well established practices and conventions on the “art” side. In the end, it is the responsibility of a utility’s protection engineer to recognize the specific needs and goals of the utility and apply the principles herein to the available equipment and technology to accomplish the best combination of reliability and economics possible.

Arc Flash energy available on a distribution system will be affected by system protective device settings. Although it is beyond the scope of this course to address this issue, the protection engineer is encouraged to research and understand the relationship between system settings and arc flash energy.

Chapter 1
Sectionalizing Philosophy

At a high level, sectionalizing is about compromises and creating the best combination of methods and practices that suits the individual utility. Goals and issues must be considered and evaluated and then implemented.

Questions that must be considered include the following:

- Which is more of a problem, blinks or longer outages?
- How high can (or should) protective devices be set?
- Are equipment maintenance cycles adequate?
- Do right-of-way cycles affect the protection plans?
- What weather patterns affect the service area?

The goal of all coordination philosophies is improved system reliability.

Inherently, the installation of any coordination device sacrifices the electric service to the loads and customers down line for the greater good of maintaining service to the rest of the customers. The device may protect major or critical loads by dropping long exposures to noncritical loads during fault conditions. But one must remember that every sectionalizing device sets a priority of service because its operation stops electric service, even temporarily, to the down line customers in favor of the rest of the circuit customers.

The protection engineer must face a compromise: Higher settings for protective devices typically will improve reliability on a distribution system by reducing the number of nuisance operations while allowing for more down line devices to be applied. On the other hand, lower settings for protective devices can improve the security of the system by clearing higher-impedance faults (at the expense of increased operations).

No single approach is right for all systems and, many times, not even for all portions of one system. Urban and rural service areas have different characteristics and different approaches may be appropriate. This course suggests an approach for determining settings for typical environments. It is important to understand the methodology and what can be achieved (as well as what cannot be achieved) rather than to use rote settings or values.

Fault Types

Faults can generally be categorized as temporary or permanent. It is easy to agree on one thing in system protection: that permanent faults need to be disconnected or they will disconnect themselves through destruction of the system. Studies have shown that a majority of faults are temporary in nature. Historically, utilities have used devices to clear temporary faults and restore service without manual intervention. These same devices also clear permanent faults but require manual intervention to restore service afterward.

The application of these devices, including how many to use, how to use them, and how to set them depends on the sectionalizing goals of the utility. Any fault or short circuit draws fault current depending on the system and fault impedance.

Zones of Protection

In developing a sectionalizing study, maximum and minimum fault currents must be calculated. *Maximum fault current* levels are used to ensure that interrupting devices have adequate capabilities and ratings to handle the full amount of fault current to which they may be exposed. *Minimum fault current* levels are used to determine the zone of protection for a particular device. Determining the minimum fault current is a challenge, as fault currents can be below load levels. Certain assumptions are required because of the variability of faults on distribution systems. Utilities have used such methods to estimate minimum fault current levels as:

- Assuming some percentage of maximum fault current,
- Assuming some multiple of load current, and
- Assuming some fault impedance (*Zf*) level.

Many utilities have used the fault impedance method successfully, and this method will be described in this course. The question that has always been considered is "What fault impedance should be used?" The recommended value is often in the range of 30 to 40 ohms for overhead lines and 10 to 20 ohms for underground lines.

From an engineering perspective, any ground fault resistance used in selecting minimum ground trip levels is a "design value" selected for calculation purposes only and should not be confused with the ground fault resistance that might occur. The values of 30 and 40 ohms have been used for many years on systems. The actual value used should be determined by the utility's engineer. Such a practice of selecting a method that allows for the possible detection of low-level ground faults while considering system voltage, load current, phase unbalance, and system coordination is considered prudent and sound utility engineering.

Fuse Saving

One method of system protection and sectionalizing is the proper application of power fuses on the distribution system. This is an economical method to provide additional sectionalizing locations, but has one major drawback. When the fuse blows, a service technician must go to the location, determine the cause of the fault, and re-fuse. Automatic devices, such as reclosers and circuit breakers, will reset themselves after operating a few times short of lockout, but at a considerable added cost. Fuses, by their nature, are a time-current device. A given current for a given time will melt or “blow” the undamaged fuse. Temporary faults can also melt the fuse.

To avoid an outage and the associated service technician’s visit, the up line recloser may have a “quick-trip curve” enabled. This allows the up line device to quickly de-energize and reenergize the line with the intention to save the fuse from blowing. Unfortunately, this “blinks” the lights of a much larger portion of the system.

With today’s demand for improved power quality, including fewer blinks, this fuse-saving philosophy is being avoided, for at least a portion of the time, by some systems. By disabling the reclosers’ quick-trip operation and allowing the fuses to blow, the smallest possible portion of the system experiences the outage. But, unfortunately, when a lightning storm blows through, many fuses are blown that could have been saved. Some systems can switch from the fuse-blowing philosophy to the fuse-saving philosophy, and vice versa, by re-enabling or disabling the quick trip feature with distribution automation systems.

Some systems accept the fact that blinks caused by temporary faults are the real world and that the power system cannot provide blink-free power to its customers. In such systems, it is strongly suggested that each customer provide its own voltage protection in the form of uninterruptible power supplies (UPS) to critical loads, including home personal computers, just as they must be protected from surges by surge suppressors.

System Sectionalizing Studies

Sectionalizing studies should be reviewed at frequent intervals to ensure that they are adequate. The frequency of review should be driven by the rate of change of the system itself. When load currents or system configurations experience significant changes, the sectionalizing study should be updated to review the impact on devices.

Major system changes would also necessitate that a sectionalizing study be performed as part of the work. The following would typically determine the need for a new study:

- Constructing a new substation,
- Increasing substation transformer capacity,
- Adding new substation feeders,
- Changes in available fault current due to transmission and/or distribution improvements,

- Major re-conductoring projects, whether increasing conductor size on existing three-phase lines or converting from single phase to three phase, or
- Conversion to a higher operating voltage.

The following is a list of individual steps involved in making a sectionalizing study. These steps provide an orderly overview of the process.

1. Obtain complete data on the distribution system and determine all device types that are likely to be used in the study.

2. Select preferred locations for sectionalizing devices. Determination of locations is based on operational concerns, outage histories, and review of system configurations.

3. Calculate all available fault current at each tentative sectionalizing device location.

4. Select feeder protection to provide optimum coverage on the feeder and adequate coordination with substation transformer protection.

5. Starting at the substation feeder protection level, make sure each device meets the utility's goals for sectionalizing and coordination. Revise locations and settings as necessary.

6. Check the selected devices for voltage rating, continuous current rating, interrupting current rating, and minimum pickup rating. Make sure each device is applied within its rating and will respond to minimum fault current within its zone of protection.

7. Prepare written instructions for additions and changes to sectionalizing devices and update existing circuit diagrams.

After the basic data have been accumulated, the next step in the study is to determine tentative locations for sectionalizing devices. These locations may be revised after the short-circuit currents are calculated and load currents checked. Judgment and knowledge of the system, including terrain, must be used for each case, but the following may be helpful: The number of automatic sectionalizing devices used in series should be kept to a reasonable level. There are obvious advantages and disadvantages to the number of devices in series. More devices can help reduce the number of affected customers, but more devices also can create greater coordination difficulties, causing mis-operations. Non-automatic devices, such as disconnect switches, can be very helpful in restoration when used judiciously between automatic devices. "High-reliability zones" have been suggested to improve system performance. In these zones, efforts are focused on the feeder from the source to the first set of feeder devices. Within this zone, all taps are provided with some form of sectionalizing to reduce the possibility of feeder operations. Outside of this zone, more judgment may be used in weighing protection devices versus exposure. Main sectionalizing devices should be visible and accessible from roads during any season of the year. Sectionalizing devices should be located where they will not disrupt service to critical customers. Generally, such devices should be placed just beyond these customers.

Chapter 2
Fault Current Calculations

The discussion and the information in this chapter are based on the following assumptions:

- The frequency of the system is 60 hertz,
- All distribution lines have multi-grounded neutral conductors,
- Underground lines are made up of direct-buried, single-phase jacked cables with aluminum or copper conductors and bare copper concentric neutrals. The voltage rating of the cable is 25 kV or less,
- The substation transformers are connected delta on the supply side and wye-grounded on the load side, and
- The system is radial (i.e., no connected loops).

In a sectionalizing study, it is necessary to calculate both the maximum fault current and the minimum fault current at each sectionalizing point. In addition, the minimum fault current must be calculated for the end of each line.

There are four possible types of fault: *three-phase, double line-to-ground, line-to-line, and single line-to-ground*. Three-phase faults can occur only on three-phase circuits; line-to-line and double line-to-ground faults can occur on three-phase or V-phase circuits, and line-to-ground faults can occur on any type circuit. As a result of the multi-grounded neutral construction of overhead lines, the line-to-ground fault is by far the most common, although other types do occur. For underground cables, the only type of fault that is likely to occur is a line-to-ground fault. However, the impedance of underground cable to three-phase and line-to-line faults is given in this course because, for combined underground-overhead lines, where the overhead section is farther from the substation than the underground cable, it is possible that a fault on the overhead line could cause either line-to-line or three phase fault current to pass through the cable.

The three-phase fault current generally determines the maximum fault current level for three-phase lines. Near the substation, however, it is possible that a line-to-ground fault may produce a larger fault current. This is because line-to-ground faults see a lower source impedance with a delta/grounded-wye transformer connection, but a higher impedance per mile of line than three-phase faults. Thus, to determine the maximum fault current on a three-phase line, it is necessary to calculate the line-to-ground fault current as well as the three-phase fault current up to that point on the line where the line-to-ground current becomes equal to or less than the three-phase current. (See Figure 1)

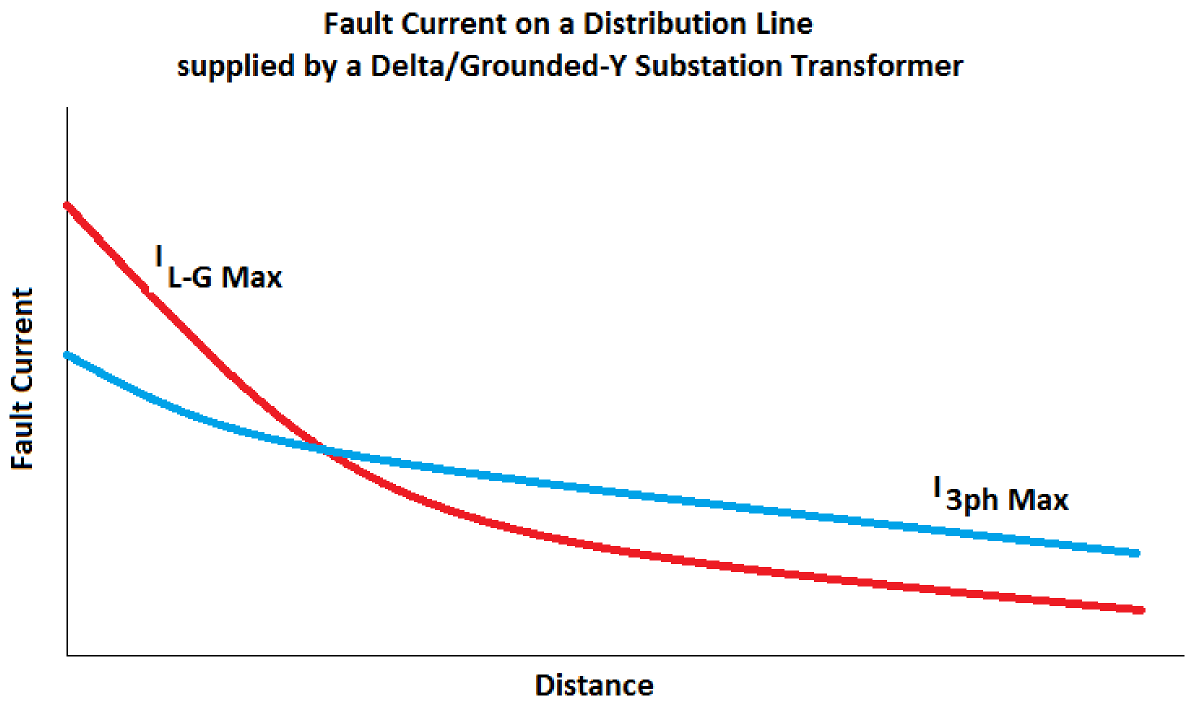


Figure 1

For V-phase and single-phase lines, line-to-line and line-to-ground faults, respectively, yield the maximum fault current. Double line-to-ground faults usually yield neither a maximum nor a minimum value for any type of line and, thus, do not normally need to be calculated. [For an in-depth understanding of the different fault currents and how to perform detailed fault current calculations see our course Symmetrical Components, e293.]

Table 1 summarizes, for each type of line, what type of fault will yield the maximum and minimum fault current values. The table is applicable for overhead, underground, and combined overhead-underground lines.

Table 1 Fault Current Values for Various Types of Faults		
Line Type	**Fault Type That Yields**	
	Maximum Fault Current	**Minimum Fault Current**
Three-Phase	Three-phase fault or Line-to-Line ground fault near substation	Line-to-ground fault*
V-Phase Line	Line-to-line fault (line-to-ground fault near a substation	Line-to-ground fault*
Single-Phase	Line-to-ground fault	Line-to-ground fault*
*A value for fault resistance must be included.		

Calculation Method for Determining Fault Currents

A calculation method for determining fault current is presented immediately below. With the advent and widespread usage of personal computers and specialized engineering software, there has been less and less reliance on manual calculations and there are various brands of engineering analysis software that will readily perform these calculations once an engineering model has been built and properly configured for the exact power system.

Regardless of the type of fault, there are three main components of the impedance offered to the fault:

1. The impedance of the source,
2. The impedance of the substation, and
3. The impedance of the distribution line up to the location of the fault.

For the minimum fault current, a fourth impedance, the fault resistance component, is added.

For most cases, the calculation of a fault current consists of determining these three impedance components (four for minimum fault current), finding the total impedance offered to the fault, and dividing the system line-to-ground voltage by this impedance.

The first step is the calculate the source impedance this is dependent on the fault type. The following formulas can be used to determine the source impedance for line-to-ground faults, three-phase faults, and line-to-line faults.

For source impedance:

Line-to-Ground faults,

$$Z_S = \frac{V_L^2}{I_{S(L-L)} * V_{S(L-L)}}$$

$$Z_S = \frac{2}{\sqrt{3}} * \frac{V_L^2}{I_{3S} * V_{S(L-L)}}$$

$$Z_S = 2Z_1 * \frac{V_L}{V_{S(L-L)}}$$

Three-Phase Faults,

$$Z_S = \frac{3}{2} * \frac{V_L^2}{I_{S(L-L)} * V_{S(L-L)}}$$

$$Z_S = \sqrt{3} * \frac{V_L^2}{I_{3S} * V_{S(L-L)}}$$

$$Z_S = 3Z_1 * \frac{V_L}{V_{S(L-L)}}$$

Line-to-Line Faults,

$$Z_S = \sqrt{3} * \frac{V_L^2}{I_{S(L-L)} * V_{S(L-L)}}$$

$$Z_S = 2 * \frac{V_L^2}{I_{3S} * V_{S(L-L)}}$$

$$Z_S = 2\sqrt{3}Z_1 * \frac{V_L}{V_{S(L-L)}}$$

Where,
V_L = line-to-ground voltage on load side of substation.
$Vs_{(L-L)}$ = line-to-line voltage on supply side of substation.
$I_{s(L-L)}$ = Line-Line Fault Current on Source side of substation
I_{3s} = Three-Phase fault current on source side of substation
Z_1 = Positive-sequence impedance on source side of substation

For Transformer Impedance:

Determine the substation transformer size, voltage, and impedance in percent from the nameplate information or from the manufacturer. The impedance should be resolved into its reactive and resistive components either by using the formulas given below or by using a ratio based on judgment.

The substation transformer impedance is generally given as a percent and this value can be converted to ohms using the following formula,

$$Z_t = \frac{Z_t\,(\%) * V_t^2}{kVA * 100{,}000}$$

Where,
Zt (%) = Transformer impedance, percent.
kVA = Transformer kVA, per phase.
V_t = Transformer voltage, phase to phase.

Once the transformer impedance is determined, it can be resolved into its reactive and resistive components, either by using the formulas given below,

$$Rt = 0.2Zt \qquad Xt = 0.98Zt$$

Generally the power supplier will furnish the source impedance. These values—Z_1 (positive-sequence impedance), Z_2 (negative sequence impedance), and Z_0 (zero-sequence impedance)—are usually given in $R + jX$ format as a percent or per unit (P.U.) value on a 100 MVA base. The substation transformer size and impedance information is generally known and usually takes the form of a percent impedance on the transformer base rating. The source and substation transformer impedance are then usually converted to ohmic values.

For Line Impedance:

Find the distribution line impedance to any point on the system, multiply the appropriate value from in Tables 2 or Table 3 by the number of miles of line from the substation to the point being considered. If two or more different-size conductors are used from the substation to the point, add the total resistance of the first size to the resistance of the next size to the point, then add the total reactance of the first size to the reactance of the next size, etc. Add up separately the resistance and reactance components determined in the steps above. (When calculating minimum line-to-ground fault current, be sure to include a fault resistance value.) Find the total impedance and divide the system line-to-ground voltage by this impedance value to determine fault current.

Impedance values for the lines can be determined from the following tables. Table 2 is for three-phase overhead lines and shows the values for several typical wire sizes.

Table 2
Overhead Distribution Line Impedance Values
(Ohms/Mile)

	R_L	X_L
336.4 MCM ACSR	0.278	0.632
266.8 MCM ACSR	0.350	0.653
4/0 ACSR	0.441	0.712
3/0 ACSR	0.557	0.727
2/0 ACSR	0.702	0.742
1/0 ACSR	0.885	0.756
2 ACSR	1.409	0.780
4 ACSR	2.240	0.805
6 ACSR	3.560	0.853

Note: The reactance values shown in this table are based on standard 8' crossarm spacing with one pole top pin. Other configurations will result in different reactance values.

Table 3 is for three-phase underground lines.

Table 3 **Underground Distribution Line Impedance Values** (Ohms/Mile)		
AAC Conductor	R_L	X_L
350 MCM	0.298	0.180
250 MCM	0.410	0.256
4/0	0.606	0.271
3/0	0.741	0.293
2/0	0.941	0.311
1/0	1.363	0.349

With the source, transformer, and line resistance and reactance values determined, we can now calculate the maximum three-phase fault current,

$$I_{max} = \frac{V_L}{\sqrt{((R_s+R_t+R_{Dist})^2+(X_s+X_t+X_{Dist})^2)}}$$

It is necessary to calculate minimum fault currents for coordination purposes and also to define a maximum "reach" or "zone of protection" of an overcurrent protective device. To calculate minimum fault current, a value of fault resistance should be added to the resistance component of total system impedance up to the point of fault.

Before we look at an example, we need to review per unit calculations.

While a complete discussion of per unit or percent quantities is beyond the scope of this course, the following is a short review of the various quantities. Both the percent and per unit methods of calculation are simpler than using actual amperes, ohms, and volts. This discussion is based on the constants for fault current calculations for commonly encountered. See Table 4 for per unit calculation formulae.

Table 4

Per-Unit Formula

$$\mathbf{Z}_{\mathrm{PU}} = \frac{\textbf{Actual Impedance}}{\textbf{Base Impedance}}$$

$$\mathbf{I}_{\mathrm{PU}} = \frac{\textbf{Actual Amps}}{\textbf{Base Amps}}$$

$$\mathbf{V}_{\mathrm{PU}} = \frac{\textbf{Actual Voltage}}{\textbf{Base Voltage}}$$

Note: Per Unit values * 100 = Percent values

$$\%\mathbf{V} = \mathbf{I}_{\mathbf{PU}} * \%\mathbf{Z}$$

$$\mathbf{V}_{\mathbf{PU}} = \mathbf{I}_{\mathbf{PU}} * \mathbf{Z}_{\mathbf{PU}}$$

$$\mathbf{Z}_{\mathrm{Base}} = \frac{\textbf{Rated Voltage}}{\textbf{Rated Current}}$$

$$\mathbf{Z}_{\mathrm{Base}} = \frac{\boldsymbol{V_{LL}^2}}{\boldsymbol{MVA_{Base}}}$$

$$\mathbf{Z}_{\mathrm{Base\ Transformer}}\% = \frac{\textbf{Base MVA}}{\textbf{Actual MVA}} * \textbf{Actual Impedance}\ (\%)$$

$$\mathbf{I}_{\mathrm{Base}} = \frac{\textbf{Base MVA}}{(\mathbf{V}_{\mathbf{LL}} * \sqrt{\mathbf{3}}}$$

Here are a couple of examples of common per unit calculations.

What is the per unit impedance value for an actual impedance of 6.71 ohms on a 100 MVA base at 12.47 kV?

The base impedance is given by,

$$Z_{Base} = \frac{V_{LL}^2}{MVA_{Base}}$$

So,

$$Z_{Base} = \frac{12.47^2}{100}$$

$Z_{Base} = 1.55$

$$Z_{PU} = \frac{Z_{Actual}}{Z_{Base}}$$

$$Z_{PU} = \frac{6.71}{1.55}$$

$Z_{PU} = 4.3$

What is the transformer impedance for a 25 MVA, 7.5% impedance transformer on a 100 MVA base?

Use this formula,

$$Z_{Base\ Transformer}\% = \frac{\text{Base MVA}}{\text{Actual MVA}} * \text{Actual Impedance (\%)}$$

$$Z_{Base\ Transformer}\% = \frac{100}{25} * 7.5$$

$Z_{Base\ Transformer}\% = 30\%$

Let's look at an in depth fault calculation example. The following data is provided by the power supplier, Given Data

The source impedance from the power supplier for a 69kV Substation:

$$\left.\begin{array}{l} Z_1 = 7.82 + j20.8\% \\ \\ Z_0 = 16.60 + j58.78\% \end{array}\right\} \text{ on a 100-MVA base @ 69 kV}$$

The transformer data is generally found on the transformer nameplate,

Transformer size = 10/12/14 MVA
Transformer impedance = 7.09%
Transformer voltage = 69 kV HS and 7.2/12.47 kV LS

Transformer Impedance:

Convert transformer impedance to 100 MVA base:

$$\frac{100}{10} * 7.09\% = 70.9\% \text{ on 100 MVA base}$$

Spread transformer impedance into its *R* and *X* components (percent on 100 MVA):

70.9 % * (0.2 + j0.98) = 14.18 + j69.48 (percent on 100 MVA)

Source plus Transformer Impedance

Total impedance at service point (percent on 100 MVA at low side):

$Z_{1\,LS} = Z_1 + Z_t$

$Z_{1\,LS} = 7.82 + j20.87 + 14.18 + j69.48$

$Z_{1\,LS} = 22.0 + j90.352$ (percent on 100 MVA)

Since the transformer is a Delta-Wye configuration, the zero sequence source impedance doesn't flow through the transformer, therefore,

$Z_0 = Z_t = 14.18 + j69.482$ (percent on 100 MVA)

To convert to ohms we first find base ohms using the formula from Table 4,

$$Z_{\text{Base}} = \frac{V_{LL}^2}{MVA_{Base}}$$

We know the low-side voltage is 12,470 kV and the base MVA is 100 MVA, or 100,000 kVA, so,

$$\text{Base Ohms} = \frac{12.47^2}{100}$$

Base Ohms = 1.55

Now multiplying the percent impedances by this value we have,

$Z_{1\ LS}$ = (22.0 + j90.352) / 100 * 1.55

$Z_{1\ LS}$ = 0.341 +j1.40046 ohms

Z_0 = (14.18 + j69.482) / 100 * 1.55

Z_0 = 0.22 +j1.080 ohms

The positive-sequence impedance is then,

$$Z_1 = \sqrt{0.341^2 + j1.4046^2}$$

Z_1= 1.4454 ohms

Impedance for phase-to-neutral faults:

$$Z_{LN} = \sqrt{\frac{(Z_1 + Z_2 + Z_0)^2}{3}}$$

$$Z_{LN} = \sqrt{\frac{(0.341 + j1.4046 + 0.341 + j1.4046 + .220 + j1.080)^2}{3}}$$

$$Z_{LN} = \sqrt{0.3007^2 + j1.2964^2}$$

Z_{LN} = 1.3305 ohms

Fault Currents at the 7.2/12.47 kV Bus

Three-phase current = $\frac{V_{LL}}{(1.73 * Z_1)}$ = 12,470 / (1.73 * 1.4454) = 4,981 amps

Phase-to-phase current = $\frac{V_{LL}}{(2 * Z_1)}$ = 12,470 / (2 * 1.4454) = 4,314 amps

Phase-to-neutral current = $\frac{V_{LL}}{(1.73 * Z_{LN})}$ = 12,470 / (1.73 * 1.3305) = 5,411 amps

Where,
V_{LL} = line-to-line voltage in volts, (not in kV)

Calculate Minimum Line-to-Ground Fault

Here is where we have to insert a fault impedance such as 30 or 40 ohms or some other value determined by the application of education and experience, industry standards, research, etc.

Ground fault impedance = $R + j0$

Use engineering judgment and experience to determine R, and in this example, we will use 40-ohms.

$Z_{LG} = Z_{LN}$ + ground fault impedance

Remember our line to neutral impedance is,

$Z_{LN} = 0.3007 + j1.2964$

Therefore,

$Z_{LG} = (0.3007 + j1.2964 + (40.0 + j0)$

$Z_{LG} = 40.3007 + j1.2964$

$Z_{LG} = \sqrt{40.3007^2 + j1.2964^2}$

Z_{LG} = 40.32 ohms.

Line-to-Ground Fault

Line-to-ground fault = $\frac{V_{LL}}{(1.73 * Z_{LN})}$

Line-to-ground fault = 12,470 / (1.73 * 40.32)

Line-to-ground fault = 178.6 amps.

In this example, we found the faults currents to be,

Three-Phase Fault = 4,981 amps

Single Line-to-Ground Fault = 5,411 amps

Single Line-to-Ground Minimum Fault = 179 amps.

These values are at the transformer and do not consider any line impedance. The next example will include line impedance in the calculations.

Distribution Voltage Transformation

When a line is encountered that incorporates an autotransformer or two-winding transformer used for system voltage conversion, there are several additional steps that must be taken to find the fault current beyond these devices.

Using the previously outlined procedure determine the resistance and reactance values of the total impedance (source, substation transformer, and distribution line) from the substation to the point on the line where the step-up or step-down transformer is located. Using the formula below, determine the impedance of the autotransformer in ohms. (For the purpose of this course, it is assumed that only single-phase autotransformers or two winding transformers will be encountered.)

Two-winding transformer or autotransformer,

$$\boldsymbol{Z_t = \frac{\%Z_t * (V_{LN})^2}{KVA * 100,000}}$$

Where,
V_{LN} = the line-to-neutral voltage on the load side of the Transformer.
$\%Z_t$ = the percent impedance of the transformer given at rated kVA and voltage.
kVA = the kVA rating of the transformer.

Resolve the impedance into its reactive and resistive components, either by using the formulas given below or by taking a ratio based on engineering judgment.

$$\mathbf{Rt = 0.2}\boldsymbol{Zt} \qquad \boldsymbol{Xt} \mathbf{= 0.98}\boldsymbol{Zt}$$

Reflect the source, substation transformer, and distribution line impedance (Z_{STD}) to the load side of the voltage transformation transformer by the appropriate method shown below.

(1) Step-up transformation:

$$\boldsymbol{Z}_{\mathbf{STD}} \textbf{ load side} = (\boldsymbol{N}^2)(\boldsymbol{Z}_{\mathbf{STD}} \textbf{ source side})$$

(2) Step-down transformation:

$$\boldsymbol{Z}_{\mathbf{STD}} \textbf{ load side} = \left(\frac{\mathbf{1}}{\boldsymbol{N}^{\mathbf{2}}}\right)(\boldsymbol{Z}_{\mathbf{STD}} \textbf{ source side})$$

Where,
Z_{STD} Load Side is in ohms
Z_{STD} Source Side is in ohms
N= $V_{HS\ LN}$ / $V_{LS\ LN}$
$V_{HS\ LN}$ = high side line-neutral voltage
$V_{LS\ LN}$ = low side line-neutral voltage

Add the distribution line resistance and reactance values from voltage transformation transformer location to the location of the fault to the R and X values:

$$\boldsymbol{R}_{\mathbf{total}} = \boldsymbol{R}_{\mathbf{STD}} \textbf{ load side} + \boldsymbol{R}_{\mathbf{auto}} + \boldsymbol{R}_{\mathbf{dist}}$$

$$\boldsymbol{X}_{\mathbf{total}} = \boldsymbol{X}_{\mathrm{STD}} \textbf{ load side} + \boldsymbol{X}_{\mathbf{auto}} + \boldsymbol{X}_{\mathbf{dist}}$$

Determine the fault current, using the formula below and the and R and X values:

$$\boldsymbol{I_{Fault}} = \frac{\boldsymbol{V_{LG}}}{\sqrt{(\boldsymbol{R^2_{total}} + \boldsymbol{X^2_{total}})}}$$

To find the fault current that would appear on the source side of the voltage transformation formula, use the appropriate formula below:

Step-up voltage transformation:

Source-side fault current = (*N*) (load-side fault current)

Step-down voltage transformation:

Source-side fault current = (1/*N*) (load-side fault current)

The following is a sample problem showing the calculations.

Determine the three-phase fault current at point 1 in the diagram in Figure 2.

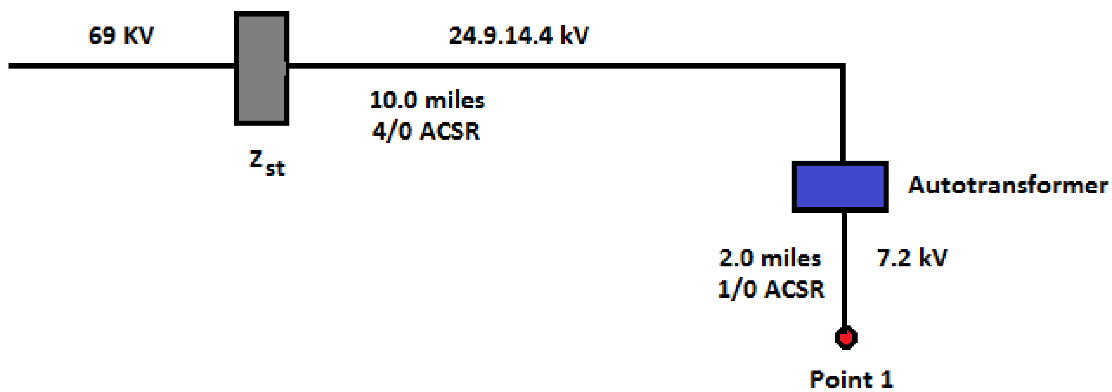


Figure 2

The step-down autotransformer characteristics are 200 kVA, 14.4 to 7.2 kV, impedance is 2.63%. The line to the autotransformer is 4/0 ACSR. From Table 2, we find the impedance and then multiply by the mileage. For 10 miles of 4/0 ACSR we have,

$Z_{dist} = (0.441 + j0.712)\ (10) = 4.41 + j7.12$ ohms (obtained from Table 2)

Step 1: Determine Z_{STD}

Assume the source and transformer impedance is,

$$Z_{st} = 0 + j3.6$$

The 4/0 ACSR impedance is,

$Z_{dist} = 4.41 + j7.12$

Therefore,

$Z_{std} = Z_{st} + Z_{dist}$

$Z_{std} = 0 + j3.6 + 4.41 + 7.12$

$Z_{std} = 4.41 + j10.72$ ohms @ 14.4 /24.9 kV

Step 2: Determine Autotransformer impedance

$$Z_{auto} \text{ load side } = \frac{\%Z * V_L^2}{kVA * 100{,}000}$$

Z_{auto} load side = 2.63 * 7,200^2 / (200 * 100,000)

Z_{auto} load side = 6.82 ohms

$R_{auto} = 0.2 * Z_{auto} = 1.36$ ohms

$X_{auto} = 0.98 * Z_{auto} = 6.68$ ohms

$Z_{auto} = 1.36 + j6.68$ ohms.

Step 3: Reflect Z_{STD} to the load side of the autotransformer

Z_{std} loadside $=1/N^2 * (4.41 + j10.72)$

Since N = 14.4 / 7.2 = 2

Z_{std} loadside $=1/2^2 * (4.41 + j10.72)$

Z_{std} loadside $=1.1 + j2.68$

Step 4: Determine total impedance including line and autotransformer

We need the impedance of the 2.0 mile section of 1/0 ACSR beyond the autotransformer to the point of the fault. We get the resistance and reactance from Table 2,

R_{dist} = 2.0 mi * 0.855 ohms/mi = 1.77 ohms

X_{dist} = 2.0 mi * 0.756 ohms/mi = 1.51 ohms

Then we have,

$Z_{std} = 1.10 + j2.68$

$Z_{auto} = 1.36 + j6.68$

$Z_{dist} = 1.77 + j1.51$

Therefore,

$Z_{total} = Z_{std} + Z_{auto} + Z_{dist}$

$Z_{total} = 1.10 + j2.68 + 1.36 + j6.68 + 1.77 + j1.51$

$Z_{total} = 4.23 + j10.87$

Step 5: Calculate the fault current

$$I_{3\varphi\ \text{fault}} = \frac{7{,}200}{\sqrt{4.23^2 + 10.87^2}}$$

$I_{3\varphi\ \text{fault}}$ = 617.3 amps.

The same procedure can be followed for a step-up autotransformer or two-winding transformer.

Fault Current on Supply Side

A fault anywhere on the load side of the substation causes a current to flow on the supply side. The following formulas can be used to determine the supply side current. Note that source current, $I_{s,}$ is not necessarily the same in all three phases. The formulas give the maximum supply currents in any one phase.

For line-to-ground fault:

$$\mathbf{I_S = \frac{V_L * I_L}{V_{S\,(L-L)}}}$$

For three-phase fault:

$$\mathbf{I_S = \frac{V_L * \sqrt{3}\, I_L}{V_{S\,(L-L)}}}$$

For a line-to-line fault:

$$\mathbf{I_S = \frac{2V_L * I_L}{V_{S\,(L-L)}}}$$

Chapter 3
Sectionalizing Equipment

The goal of sectionalizing is to minimize the number and duration of outages seen by customers and to do this the tools of sectionalizing must be understood and judiciously applied. It is impossible to eliminate outages completely, so the goal of the protection engineer and system planner is to understand and best apply the resources available. The following is a brief discussion of some of the most common tools used on distribution systems and their characteristics.

Circuit Breakers

Circuit breakers can have vacuum, oil, SF_6 gas, or air as an interrupting medium. Currently, in the distribution market, a vast majority of breakers sold for feeder protection are vacuum interruption circuit breakers. The construction and testing by manufacturers for medium-voltage circuit breakers are defined by a number of national and industry standards (including ANSI, IEEE, NEMA, and others). When used for distribution feeder protection, they are normally controlled by time-overcurrent relays and reclosing relays. Circuit breakers require an external power source for closing and tripping.

Automatic Circuit Reclosers

Automatic circuit reclosers have been used successfully on rural circuits for many years. Reclosers are available with a wide range of current and voltage ratings and are suitable for use on virtually all distribution circuits.

The original concept of reclosers was to provide a self-contained, low-cost tripping and reclosing circuit interrupter, which could be used economically for pole-mounted protection of distribution feeders.

This type of recloser is commonly referred to as a *series-coil* recloser. These reclosers employ a series coil that causes tripping of the recloser at approximately two times the continuous current rating of the coil. They can be either single-phase or three-phase devices. They may employ either a hydraulic timing mechanism for time-delayed operating curves or may feature a hold-closed method of operation after the fast curve operations. Some of the heavy-duty three-phase or single-phase models may use a closing solenoid connected between phases or from phase to neutral. Series coil reclosers are used in both substation and line applications.

Some three-phase reclosers require an external power source for tripping and closing. This type of recloser is commonly referred to as *non-series-coil* recloser. Reclosers that are electronically controlled are more versatile and more easily modified.

They require a power source for operation, which usually is an AC source if used on the line, or they may use DC from a battery bank if used in a station. This type of recloser closely resembles a circuit breaker in its function and operation. Three-phase reclosers with advanced controls are similar in functionality and information recording to electronic relays, and are routinely used in stations as feeder protection.

Automatic circuit reclosers come in a variety of single-phase electronically controlled units, which offer a wide variety of coordination options and reporting functions. Likewise, electronically operated three-phase units are now available that can be configured for single- or three-phase trip or lock-out operations, and which offer improved flexibility in sectionalizing, reliability, and SCADA schemes.

Automatic Line Sectionalizers

An *automatic line sectionalizer* is an oil, air, or vacuum switch that automatically opens to isolate a faulted section of line. It employs either a hydraulic or electronic counting mechanism, which is actuated by a system overcurrent and an up line circuit breaker or recloser tripping action. Unlike other overcurrent protection devices, a sectionalizer does not operate on a time-current curve.

Automatic line sectionalizers are used principally in branch circuits where:

- Small loads or little circuit exposure will not justify reclosers (typically sectionalizers are less expensive than reclosers).
- It is desirable to establish an automatic sectionalizing point but time-current curve coordination with other sectionalizing devices would be difficult or impossible.

Automatic line sectionalizers are available as either three-phase or single phase devices. They are not rated to interrupt fault current and, therefore, must be used in conjunction with up line reclosers or circuit breakers capable of sensing and interrupting minimum fault currents beyond the sectionalizer. The recloser or circuit breaker must sense a fault and perform the circuit tripping and fault-clearing operation. The sectionalizer counts the preset number of recloser or breaker trips and senses minimum fault current through the sectionalizer. After both conditions are met, the sectionalizer automatically locks open during the open circuit time of the breaker or recloser. A sectionalizer may be used for switching loads within its load-interrupting rating.

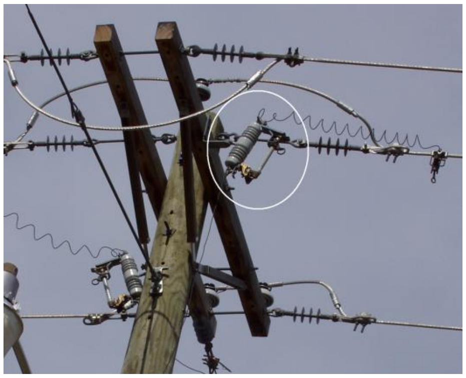
Line Switches

Line switches typically do not have overcurrent characteristics, but are extremely valuable in the operation of a distribution system, especially in the restoration of service. For very long or

heavily loaded circuits, line switches can be used in conjunction with automatic circuit reclosers to help isolate problems and restore service to as many customers as possible.

Line switches can be individually operated or gang-operated, load-breaking or non load-breaking, and manually operated or remotely operated through SCADA systems. Load-break gang-operated switches are typically located at open points between feeders and substations to facilitate switching load between areas for maintenance or restoration. Non-load-break switches are economically beneficial in locations where main feeders go cross country or through heavily treed rights-of- way or just past a load center; they can be used to isolate the part of a circuit requiring repair, allowing the feeder to be reenergized to that point.

Fused Cutouts



Fused cutouts are the most economical means of isolating sections of faulted lines on rural distribution systems.

Currently, the standard fused cutout is very popular and used for fusing line taps, underground take-offs, capacitor banks, and distribution transformers.

Typically, expulsion fuse links are used in cutouts because of their economy and versatility. Several types of expulsion fuses are available with differing curves for different applications. However, several manufacturers also provide a current-limiting fuse that can be used in a cutout for specific applications. There is available a sectionalizer that fits in a cutout and opens after sensing a fault.

Current-Limiting Fuses

Current-limiting fuses are relatively expensive compared to expulsion-fused cutouts. They are also more difficult to apply since the engineer must consider not only their continuous current rating, but also their maximum (and sometimes minimum) voltage rating and their ability to interrupt a current in less than one-half cycle. Industry standards define both “general purpose” and “backup” current-limiting fuses. In general, where current-limiting fuses are being considered, the backup type will usually prove more desirable than the general-purpose type unless the general-purpose fuses have time-current curves that nearly parallel those of expulsion fuses.

The advantages of backup current-limiting fuses are: No changes in existing fusing principles or methods are required for coordination and majority of faults should blow only the expulsion fuse, which is chosen to coordinate with the current-limiting fuse. A disadvantage of backup current-limiting fuses (CLF) is that it must be used with a coordinated expulsion fuse. If an expulsion fuse larger than the one for which the CLF has been designed to coordinate is employed, the CLF may attempt to interrupt a current below its ability to clear, resulting in a burned-up fuse and a likely system fault.

Current-limiting fuses, even though they are expensive, can often be justified such as for: Fusing distribution transformers on overhead circuits where available fault current is high and, fusing underground cables and associated equipment.

Power Fuses

Power fuses can be current-limiting, conventional expulsion, or boric acid types. They have higher interrupting ratings than distribution fused cutouts and are, therefore, seldom applied on distribution circuits unless the available fault current is extremely high. Power fuses find their largest application as transformer bank protection or the high-side fuse for relatively small distribution substation transformers.

Circuit Switchers

A *circuit switcher* is a high-voltage load-switching and fault interrupting device that usually—but not always—incorporates a disconnect switch function in the switching operation. Voltage ratings will generally cover all distribution power transformers.

It should be recognized that a circuit switcher is not a circuit breaker. It has a fault-interrupting rating less than the smallest standard rating for circuit breakers and it does not have high-speed reclosing ability. A further limitation is that there are no provisions for mounting current transformers.

Even though a circuit switcher has some limitations, it is well-suited for protection of substation transformers against secondary and internal faults, switching transformer magnetizing current, load dropping, capacitor bank switching, cable switching, and switching both series and shunt reactors.

Underground Sectionalizing Devices

Underground distribution systems are fed either directly out of a substation or fed from an overhead distribution line. These systems have evolved into almost distinct higher-current and lower-current systems. Manufacturers generally rate components at either 200 or 600 amps. There are exceptions, but for the most part these are the primary conventions.

The sectionalizing devices used in 600-amp backbone underground systems are generally pad-mounted or submersible switches that may have fused or automatically opening tap points to connect to the 200-amp system.

When a 200-amps system is fed directly from an overhead system, the most common sectionalizing device protecting the main line is a riser pole fuse. Occasionally, automatic devices such as reclosers are used to provide protection to the overhead system from underground faults when greater flexibility is desired.

When a 200-amp system is fed from an underground 600-amp system, a fuse scheme or automatic opening scheme within a pad-mounted or submersible switch is the primary sectionalizing device. Operationally, the sectionalizing device commonly used to manually isolate problems or equipment on 200-amp systems is the dead front load-break elbow.

Fault Indicators

Fault indicators can be extremely valuable tools in locating faults and restoration efforts. Fault indicators are typically available to fit certain diameters of wire and can be manually or automatically reset. For automatic reset indicators, typically current or voltage is used to determine if the fault is cleared. Various factors will determine which type is selected for specific applications. Fault indicators are especially helpful on underground systems in locating faults on the underground primary and allowing service to be restored to most or all of the remaining system.

Chapter 4
Application of Sectionalizing Equipment

In applying sectionalizing devices to electric distribution systems, four tasks need to be accomplished to assure safe and reliable electric operations:

1. Choose appropriate locations for line devices,

2. Select the proper type of device to handle the available fault duty (maximums and minimums),

3. Select the proper size of device to handle the peak load currents, and

4. Select and set the time-current characteristics (TCC) to coordinate both with the up line sectionalizing devices and the down line devices.

Before applying any sectionalizing device to a system, the system engineer should identify the proper and appropriate locations for each device. Choosing a location is based on many factors and the circumstances may change as the system operational characteristics change. Device placement is selected to isolate faulted portions of the system from the rest of the system and to assist operating personnel in the location of the fault.

Line fuses are typically applied at locations that are short single-phase taps off main three-phase feeder lines, or single-phase lines with less than 20 amperes of peak load.

Line reclosers are typically applied at locations that are: Single-phase lines with greater than 20 amperes of peak load, three-phase branches, after large industrial and commercial loads, or locations to cover the calculated minimum down-line fault conditions.

Line sectionalizers are typically applied at locations that are: Downline from line reclosers where minimum fault conditions are met, or downline from line reclosers where normally a line recloser is installed and, generally, on the ends of feeders.

Typically, single-phase reclosers are used on most moderately loaded line applications. Three-phase devices are usually utilized on heavily loaded three-phase lines where ground fault relays are needed to cover the minimum calculated fault conditions.

A distribution system experiences both underground and overhead fault conditions regularly. It is neither economical nor practical to design a system that would eliminate all system faults. Faults can be caused by a number of sources, including—but not limited to—the following:

- Weather (e.g., wind, lightning, ice, high temperatures),
- Equipment failure,
- Trees,
- Public contacts with both overhead and underground lines (by digging, in the latter case),
- Animals,
- Automobile accidents, and
- Vandalism.

Faulted conditions can present a hazard to the public and utility personnel, and can cause damage to electric system equipment. Protective systems are applied to sense these faulted conditions and to limit the consequences by clearing the fault in a timely manner. Since most of the faulted conditions on a distribution system are temporary in nature, line devices are often applied that provide for reclosing. This results in improved system reliability and improved service to the ultimate consumer.

System fault conditions are calculated on the basis of the available source impedance from the power supplier and the system impedance of all line devices to the point of the possible fault. The maximum fault conditions are calculated without any fault impedance and represent the highest level of current expected at a given line point. Such calculated levels can be used to establish the interrupting capability of the sectionalizing device that is to be applied.

For a typical electric distribution system served by a delta/wye power transformer, the maximum fault at the substation bus is the line-to-ground fault. Moving down line on the feeder, the maximum three-phase and phase-to-phase-to-ground faults are higher and are used for sizing sectionalizing devices.

Minimum faults, as stated earlier, are calculated by adding an estimated fault resistance to the available source impedance. The fault resistance is based upon the judgment of the system engineer or consultant and will represent the minimum fault current levels that are expected on the system. This judgment is usually based on the history of high-resistance fault conditions experienced on the system. The minimum levels are utilized to establish necessary line protective device pickup levels.

The maximum load current levels on all system line components are typically based on the most recent peak loading conditions that occurred on the system. This is often called the “base system.” These levels are based on peak-month consumer energy sales and allocated by using computer engineering model software. The resulting loading calculations should reflect the maximum loading conditions that have been experienced on the system.

In planning the sectionalizing system, we must not only use the maximum load calculations from the base system, the maximum conditions should also be calculated for the anticipated future load conditions. The future system peak conditions should identify the maximum anticipated loads that need to be served by the future sectionalizing system.

It is not unusual for a distribution system to experience two annual peak conditions. One condition could be for the summer and one for the winter. If such peaks are long in duration (longer than 2 or 3 hours per year), they both should be modeled and reviewed for the proper sizing of the line devices. When line devices for maximum load conditions are sized, device manufacturers should be contacted for the overloading capability of each device. Such ratings can be considered in the sizing of the line devices.

Device coordination means choosing characteristics for a line device so that it can experience a faulted condition *outside* its zone or range of protection without being tripped and still operate appropriately to clear the fault when it experiences a fault condition *inside* its zone of protection. Effective line sectionalizing requires that line device time-current characteristics have proper separation and devices work independently when faults are in their respective zones.

Guidelines for Substation Overcurrent Protection

The following is information that highlights devices used to protect substation equipment including power transformers and feeder equipment.

Power Transformer Protection

High-side devices are primarily used to protect distribution power transformers and these include fuses, circuit switchers, and breakers. Regardless of the protective device selected, the primary function of the device is to protect the transformer. The goal is to minimize the amount of time the transformer is subjected to fault current. The considerations that need to be taken into account in selecting a protective device are the size and voltage of the transformer and economics.

Fuses are the least expensive option but can be limited in performance. They are usually used on smaller units of 10 MVA or less and voltages of 69 kV or less. There are some applications where fuses are used for larger units and voltages, but these are less common.

The next option for transformer protection on the economic scale is the circuit switcher. The circuit switcher is considered a “dumb” device in that it does not contain the intelligence to operate by itself. These devices require relays to sense fault conditions and provide a trip signal to the circuit switcher before it will operate. The circuit switcher and relay combination is usually used in substations with transformer sizes above 10 MVA and/or having high-side voltages of 69 kV or higher.

Breakers are the third and usually most expensive option for transformer protection. These devices, like the circuit switchers, are considered to be dumb and require relaying to provide detection and tripping intelligence. Breakers are usually used on larger transformers and for higher voltages.

Relaying strategies used to protect transformers usually consist of a high-speed differential scheme as the primary protection and an overcurrent scheme to provide backup protection. Depending on the design scheme, the differential relay may protect only the transformer or may incorporate the secondary bus of the substation. Differential relays are based on the principle that power in is equal to the power out. When the power in does not equal the power out, and the resulting differential exceeds a certain threshold, then the relay trips.

The overcurrent relay schemes commonly used consist of phase overcurrent relays on the high side of the transformer and a ground relay on the secondary side in the neutral of the transformer. The relays are usually set by taking into account the size of the transformer, its overload capability, and the coordination with the substation distribution feeder devices. Other considerations that should be taken into account consist of the amount of expected imbalance on the secondary side and the size of the regulators being used.

The phase overcurrent relays are usually set by taking into consideration the size and overload capability of the transformer. It should be kept in mind that not all transformers are the same. Substations utilizing autotransformers will not have as high an overload capability as two winding transformers. Because of their construction, autotransformers do not have the short-circuit through-fault capability of a two-winding transformer. In coordinating the phase overcurrent with the distribution feeder, the shift in the time-current curves for the devices due to the difference in the high-side and low-side voltages needs to be taken into account.

The ground overcurrent relay must be coordinated with the distribution feeder device ground protection. It also should take into account the single winding capability of the transformer. While the balancing of feeders is a goal of a well-operated distribution system, a certain amount of imbalance can be expected at the substation. Any expected imbalance should be taken into account in determining the setting for the ground overcurrent relay to prevent the relay from tripping. The size of the voltage regulators should be considered in order to protect them from overcurrents.

Other devices that can be included in a scheme to protect the transformer are oil-level, sudden pressure, and high-temperature relays. These relays are usually internal to the transformer and can be used to trip the high-side protective device. Settings for these relays are usually specified and set by the manufacturer at the time the transformer is specified.

Low-Side Devices

On the low side, bank or station breakers may be used. Some substation designs may utilize a secondary bus device. These may be fuses, reclosers, or breakers. If something other than a fuse is used, then the device is usually set up for one shot to lockout. A bus device must coordinate with the high-side protective device and the distribution feeder devices. Alternatively, low-side protection may consist of feeder breakers or reclosers only.

Feeder Current Protection

A question that is often raised by the system engineer is what type of device should be utilized in the substation on the substation feeders. The options are generally either breakers or reclosers.

Breakers and reclosers two distinct device types manufactured under different ANSI standards. Breakers typically have higher current interrupting ratings and also can support much higher continuous load currents. Breakers typically are built as power class equipment with higher basic impulse levels (BILs) and, therefore, are usually larger in size than a recloser. Breakers have limitations on number of reclosures and, according to ANSI Standards, should be derated under certain operating conditions. Refer to the applicable ANSI breaker standard to identify their limitations.

Reclosers have traditionally been more economical and offered more options for time-current characteristics (TCCs) with available electronic controls. With the introduction of intelligent electronic devices (IEDs), more TCC options are now available for breakers.

Coordination with the source protective device can be complicated and is influenced by many variables. For the most part, the feeder device is required to coordinate with a protective fuse on the source side of the power transformer or with protective relaying that may be either electromechanical or electronic.

Coordinating with high-side fuses can be accomplished by using a method based on time-current characteristics curves adjusted by multiplying factors to compensate for fuse preloading, ambient conditions, and the number of reclosures of the line protecting device. Source-side fuses are selected to protect the electric system from a power transformer fault and to protect the power transformer from a secondary bus fault. Once the fuse size has been determined, the feeder recloser or breaker curve or curves can be evaluated and selected.

The circuit recloser or breaker must be selected to coordinate with the source-side fuse link so that the fuse does not blow for any fault on the load side of the feeder device. The cumulative heating effect of the recloser or breaker operations must be less than the damage characteristics curve (minimum melt) of the fuse link. This is accomplished through the use of multiplying factors on the recloser or breaker TCC curves that identify the damage or fatigue point of the fuse link. The modified delayed curve must be faster than the source-side fuse's minimum melt curve.

TCC curves are used to coordinate the feeder recloser or breaker with the source-side fuse link utilizing the following rule:

> *For the maximum available fault current at the recloser or breaker location, the minimum melting time of the fuse link on the transformer's source-side must be greater than the average clearing time of the recloser/breaker's slowest response curve(s), multiplied by a specific factor.*

The multiplying factors (often called "K" factors) for various reclosing intervals and operating sequences are published by fuse and recloser manufacturers. The factors range from 1.35 to 3.7 depending on the TCC curves of the recloser or breaker and the reclosing intervals selected.

One other condition that needs to be considered in coordinating source-side fuses (and relay TCC curves as well) is when there is an unsymmetrical transformer connection (delta/wye). The ratio of primary to secondary fault current will be different when plotting the TCC curves depending on the type of secondary fault realized (three phase, phase-to-phase, and phase-to-ground). The ratio factors shown in Table 5 are used to determine the amount to shift the fuse curve to reflect the TCC response to the secondary of a delta/wye transformer.

Table 5

Fault Type	Ratio Factor
Three-phase	N
Phase-to-Phase	0.87N
Phase-to-Ground	1.73N

"N" is defined as the power transformer ratio of the source phase-to-phase voltage to the load phase-to-phase voltage.

Since the phase-to-phase fault condition will result in the tightest coordination with the source-side fuse, it should be used in assuring coordination between the devices and protecting the fuse for a secondary fault. Another way of saying this is that a secondary phase-to-phase fault produces the greater amount of source-side current for a given amount of secondary current.

Therefore, plotting and reflecting the source-side fuse TCCs using the secondary phase-to-phase ratio factor produces a fuse TCC curve to the far left, resulting in the worst case condition where the minimum melt curve of the fuse should be protected.

Similar steps are required when coordinating secondary reclosers or breakers with substation source-side backup overcurrent relays. As with fuses, the TCC curves of the relays are selected that will provide protection to the electric system for a power transformer fault as well as protection of the transformer for a secondary substation fault. Once the source-side relay TCCs have been selected, the feeder recloser or breaker TCC curves can be reviewed and selected for proper coordination.

When source-side relays are used, generally the system engineer is required to coordinate the high-side overcurrent relays as well as backup ground relays off the neutral bushing of the power transformer. Care should be exercised if source-side instantaneous pickups have been selected. Normally, if instantaneous pickups have been chosen for the high-side backup overcurrent, they should be set for slightly less than the maximum reflected low-side available phase-to-ground fault to assure coordination with the low-side feeder recloser or breaker settings. Also, it is recommended that no instantaneous pickup be utilized for the backup ground relay. If used, mis-coordination is likely to occur with the feeder protective devices unless set so high that the functionality of the instantaneous setting is questionable.

One significant dilemma in coordinating with source-side electromechanical relays is dealing with relay disk movement, coasting, and reset times. When a fault occurs, the electromechanical relay disk moves toward the closed position, and it will "coast" for a short time if the fault is interrupted or removed by the down line protecting device. This additional movement is typically called coasting time or *impulse margin time* (IMT). Impulse margin times are published for various types of electromechanical relays and can vary from 0.03 to 0.06 seconds. This margin time needs to be allowed for in the relay response to assure proper coordination with the down line feeder recloser or breaker.

The time that should be added to the relay response is called the *minimum fault time* (MFT). It is calculated using the following formula:

MFT = ROT – IMT

Where,
MFT = Minimum fault time.
ROT = Relay operating time at a specific fault level or the maximum fault level
IMT = Impulse margin time.

Once calculated, the MFT can be added to the source relay response time or the feeder device to check for proper clearance and coordination.

Reset times of electromechanical relay disks are another matter that needs to be considered when defining feeder recloser or breaker settings. Electromechanical relay disks take an extraordinary amount of time to reset to their time lever or dial position. Depending on the manufacturing type and response speeds, the reset times vary from 25 to 35 seconds at the mid-time dial position. This is critical when multi-shot protection schemes are used, which is what most electric systems utilize for feeder protection.

When checking coordination with source-side relays, several methods can be used, each having their own degree of complexity. For a non-reclosing feeder recloser or breaker condition, one method is to just add 0.3 seconds to the feeder device clearing time; the source relay time must have a greater response time than this. This is a conservative and more simplistic approach. A more accurate approach is to add minimum fault times to the clearing time of the feeder device and check for clearance and coordination. Either of these approaches allow for tolerances, variations due to temperature, plus any other variables.

For coordinating reclosing feeder or breaker plans with source-side electromechanical relays, the method of checking coordination is much more complicated and important. One simple and conservative method is first to add all times of the sequence and compare the sum to the relay curves. If the added feeder device responses are to the left of the source-relay on the TCC plots, coordination exists. This method is extremely conservative and does not account for resetting of the relay disk between operations. It may not be a realistic approach for many applications.

A more accurate method is to calculate the actual relay disk travel for each trip and reclose operation of the feeder device, add recloser or breaker timing—plus impulse margin times—for each trip, and subtract the relay reset time for each reclosing interval. Calculating the total times as a percentage of relay travel will identify if coordination of the feeder recloser or breaker to the source-side relay will occur. If the total times are greater than 100%, the feeder recloser or breaker does not coordinate with the source-side relays and will result in the substation being tripped offline, causing an outage. This can be corrected by changing the last reclosing interval on the feeder device to a longer time, allowing the source electromechanical relay to reset more fully to attain adequate coordination between devices.

Fortunately, with the development of static and/or electronic relays and controls the need to coordinate with electromechanical relays is declining greatly as the new “intelligent electronic devices” (IEDs) are replacing the old forms. With such devices, relay and device responses are much easier to predict and can be more easily modified to assure proper coordination between devices.

As a rule of thumb—when not having to worry about electromechanical complexities, and where static or electronic relays are present—adequate coordination between a feeder recloser and the source-side protective device can be attained if the minimum separation of the feeder response and the source protecting device response is greater than 30 cycles. Closer separation can be allowed if more precise TCC studies are accomplished where curve tolerances, device responses, reclosing intervals, and other variables are included for the specific application being reviewed. A tool that can be used to attain such coordination is the instantaneous pickup function, if available in the feeder recloser or breaker controls, applied at the proper level to assure the desired separation mentioned above.

When feeder protection devices are equipped with both phase and ground protection, another aspect of coordination of feeder devices to source-side devices is to realize the composite TCC response of the ground and phase trip settings. In other words, when checking and confirming coordination, it is not required to look individually at phase responses and ground responses. They should be viewed as TCC responses working together for the purposes intended. With a majority of line faults being phase-to-ground, the ground current relay is going to "see" the fault the same as the phase relay, and the ground relay will respond quicker. This means that the coordination of the phase relay by itself with the source-side device is not required and unnecessary.

Coordination with the Load Device

As stated earlier, typical electric distribution substations utilize single-phase hydraulic reclosers or three-phase reclosers or breakers to protect substations from feeder faulted conditions. In recent years, electric systems have moved more and more away from the use of single phase hydraulic reclosers. This is due to feeders having higher load currents and the need for ground trip protection.

For substation feeders utilizing single-phase hydraulic reclosers, to assure proper coordination and no simultaneous operations, the separation between the feeder recloser and the down line single-phase recloser must be greater than 12 cycles at the maximum fault conditions at the down line device. From 2 to 12 cycles, possible simultaneous operations may occur. Less than 2 cycles separation means simultaneous operations will occur and there is not proper coordination.

For feeder devices with electromechanical overcurrent relays, the same coordination steps described in the earlier section must be followed. Minimum fault times, relay operating times, impulse margin times, and disk reset times must all be used to assure proper coordination.

For feeder reclosers or breakers with electronic or static relays or controls, coordination can more easily be set and established. Time current characteristics can be modified and set to adjust feeder device responses that will coordinate with whatever down line devices that may be in operation.

As a rule of thumb, where static or electronic relays or controls are present, adequate coordination between a feeder recloser or breaker and the down line protective devices can be attained when there is a minimum separation or margin of the down line feeder device response and the source-protecting device response is greater than 21 cycles or 0.35 seconds for the maximum fault at the down line location.

Guidelines for Overhead Line Protection

One of the key components of a reliable electric distribution system is the proper application of downline sectionalizing devices. Proper application will assure reduced outage times and minimize system damage due to overcurrent conditions. The following comments provide guidelines in the proper application of line sectionalizing devices.

There is a wide variety of line devices available to the system engineer for sectionalizing an electric distribution system. The devices are ever-changing, bringing operational and maintenance benefits as technology advances to fulfill the needs of the industry. Currently, the devices that are available are as follows:

- Line reclosers,
- Line sectionalizers,
- Line fuses, and
- Line switches.

Line Reclosers

Line reclosers are a self-contained device with the necessary circuit intelligence to sense overcurrent conditions, to time and interrupt the overcurrent, and to reclose automatically to reenergize the line. If the fault is "permanent," the recloser will "lock open" after a predetermined number of operations (usually three or four) and, thereby, isolate the faulted section of distribution line from the main part or source of the system.

Most faults on overhead distribution systems are temporary in nature and last only a few cycles or seconds. Statistical studies of distribution systems show that approximately 70 to 80% of overcurrent conditions on overhead lines are temporary in nature. Automatic line reclosers, with their trip and reclose capability, eliminate prolonged outages on distribution lines due to temporary faults or transient overcurrent conditions.

Automatic line or circuit reclosers are classified on the basis of single- or three-phase, hydraulic or electronic controls, and oil or vacuum interrupters. Each type has its advantages.

With the high cost associated with oil maintenance, there is a trend toward utilization of reclosers that have vacuum interrupters. Selecting vacuum interrupters increases the length of the maintenance cycle and reduces maintenance costs.

Single-phase line reclosers are used typically for protection of single-phase lines, such as branches or taps off three phase lines. They can also be used on three-phase circuits where the load is predominantly single-phase. This allows, when a permanent phase-to-ground fault occurs, one phase to be locked out while service is maintained to the remaining two-thirds of the system.

In the past, single-phase reclosers have been primarily hydraulically controlled. In recent years, more and more single-phase reclosers have been electronically controlled. Such configurations offer greater flexibility in line applications and coordinate more precisely with up line and down line devices. Such devices are considerably more expensive and have not been utilized extensively in the rural electric distribution industry. As technology improves and the costs become more reasonable, it is expected that more single-phase, electronically controlled reclosers will be utilized.

As mentioned earlier, very often on rural electric distribution lines, three single phase reclosers are installed on three-phase lines. Such applications are on lines with relatively low peak loads, have very few large three-phase loads, and phase-to-ground fault levels are not very low.

Three-phase line reclosers are used where lockout of all three phases is required for any permanent fault, to prevent single phasing of three-phase loads such as large three-phase motors. Three-phase reclosers with a ground trip accessory are also utilized when line load currents are high and minimum fault current levels are very low. In such cases, the three-phase reclosers are equipped with neutral sensing circuitry using current pickup levels much lower than the line phase currents. Three-phase reclosers have two modes of operation: single-phase trip/three-phase lockout and three-phase trip/three-phase lockout.

Single-phase trip/three-phase lockout is obtained with three single-phase reclosers mounted in a single tank with mechanical interconnection for lockout only. Each phase operates independently for overcurrent tripping and reclosing. If any phase operates to the lockout condition, the mechanical linkage trips the other two phases open and locks them open. This then prevents extended single-phase energization of three-phase loads.

Most other three-phase reclosers operate through the *three phase trip/three-phase lockout* mode. For any fault, all contacts open simultaneously for each trip operation. The three phases are mechanically linked for tripping and reclosing, and are operated by a common mechanism.

Reclosers can be purchased with hydraulic or electronic controls. The uses of three-phase hydraulically controlled reclosers have declined over the years. The industry has deferred to the electronically controlled devices, which offer improved flexibility in application, provide for better ground fault protection, and are more precise in coordination with other line devices.

Line Sectionalizers

A line sectionalizer is a protective device that automatically isolates faulted sections of line from a distribution system. Normally applied in conjunction with a backup recloser, a sectionalizer does not have any fault-interrupting capability of its own. Rather, it counts the operations of the backup device during faulted conditions and, after a preselected number of current-interrupting operations and while the source or backup device is open, the sectionalizer opens to isolate the faulted section of line. This allows the source or backup device to reclose into the remaining un-faulted portion of lines, thus restoring the lines to service. If the fault is temporary, however, it will be cleared by the source/backup device prior to the sectionalizer count to lockout, and the sectionalizer will remain closed. Then the sectionalizer automatically resets to prepare for another complete cycle of operations should a new fault occur.

Compared to fuse cutouts, which do, of course, have full interrupting capability, sectionalizers provide several advantages that, depending on the application and the particular utility's approach to overcurrent protection, can offset a higher initial cost. These advantages include application flexibility, convenience, and safety.

After a permanent fault, for example, the fault-closing capability of a sectionalizer greatly simplifies testing of a circuit, and if the fault is still present, interruption takes place safely at the backup recloser. Since replacing fuse links is not required, the line can be tested and restored to service with far more speed and convenience. Also, the possibility of error in selecting the size and type of fuse is eliminated.

In addition to providing the general advantages just cited, sectionalizers are particularly suitable for two applications where time-current characteristics (which sectionalizers do not have) might pose coordination problems:

- Sectionalizers can be used between two protective devices with operating curves that are close together. This is a vital feature in locations where additional coordination steps are impractical or impossible.

- They can be used on close-in taps where high fault magnitude prevents coordination with fuses or use of expensive high-interrupting fault reclosers.
- Sectionalizers are available in single- and three-phase versions controlled by hydraulic or electronic counting mechanisms.
- Sectionalizers do have high momentary current ratings, providing for safe closing operations on faulted lines.

Line Fuses

Line fuses are the most basic protective device available for line overcurrent protection on distribution systems. Their primary function is to serve as an inexpensive means to protect equipment against overloads and short circuits.

Fuses are available in a variety of types, offering a wide variety of time-current characteristics. The basic types are expulsion fuses and current-limiting fuses. Expulsion fuses are utilized more extensively in distribution systems than current-limiting because of cost and operational needs.

Expulsion fuses serve as expendable, inexpensive "weak link" protective devices used on distribution lines with cutouts. That is, fuse links are components that are replaced after providing the desired protection to equipment and/or distribution lines. Properly coordinated with backup reclosers, fuses can help reduce the total cost of sectionalizing equipment without reducing service reliability or increasing operational and maintenance expenses.

Fuses follow basic time-current characteristics that are described in a set of two curves. Minimum melt curves describe the current and time characteristics that are necessary for melting of a fuse to begin. Once melting has occurred, the fuse is considered to be damaged and, therefore, can no longer be relied on to function in the manner that is expected of a new fuse. Total clear curves describe the current and time characteristics that are necessary for the fuse to fail, thus clearing a fault.

Expulsion fuses can be grouped into types that have similar time-current characteristics. These types are typically designated by a letter. Often these types are referred to as the "speed" of a fuse. Typical fuse types used in the electric distribution industry, from the fastest to the slowest, are QA, K, N, T, S, and KS. Refer to Figure 3 for a summary of the total clear characteristics of a 50-amps fuse for various speeds.

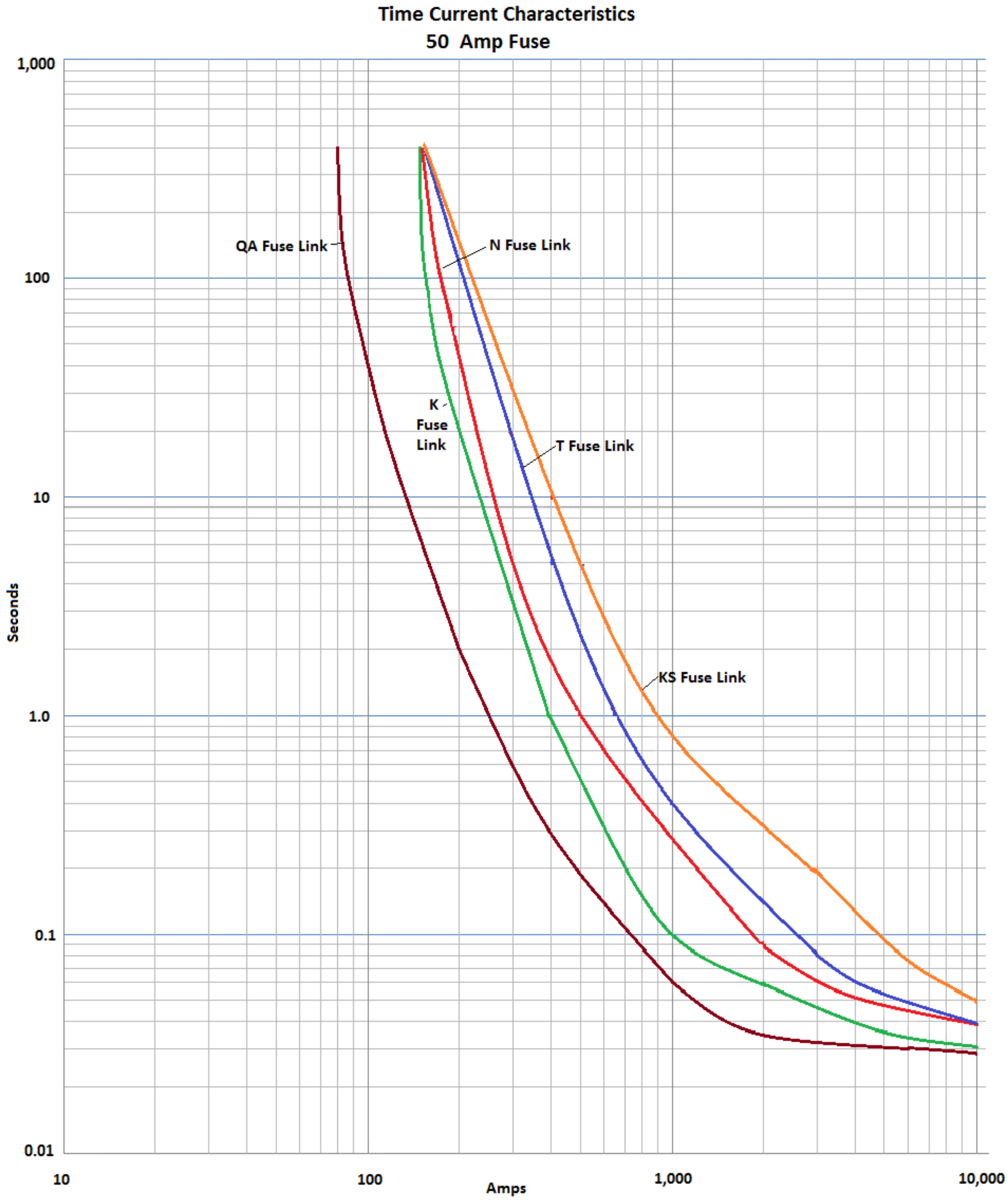


Figure 3

Current-limiting fuses (CLFs) are typically utilized on electric systems that have very high fault conditions. They are generally used to protect equipment such as distribution transformers, capacitor banks, and other devices on the system where available faults may result in catastrophic failures. With the improved design of distribution transformers and capacitor banks for applications at higher fault current locations, the use of CLFs has declined. For systems with loads very sensitive to voltage fluctuations, CLFs are used to limit fault current levels, reducing undesirable line voltage flicker. CLFs are generally very high in cost, so decisions to use them should be closely scrutinized.

Line Switches

While not typically considered as a sectionalizing device on electric distribution systems, line switches are important sectionalizing tools for aiding in power restoration. One of the key objectives of proper sectionalizing is to provide a means for isolating system faults from the rest of the system so that power can be restored. Related to this objective is to have line switches located on the electric system where portions of the system can be clearly isolated as well as to provide a means whereby loads can be transferred to other system sources until the faulted lines can be repaired. Single-phase and three-phase switches should be carefully placed on the system to allow for such system operations.

Considerations for Sizing and Locating Devices

Before considering the application of any line sectionalizing device, accurate knowledge of true system conditions must be determined and available to the system engineer. Without such information, system damage is sure to occur and service reliability will be poor.

It is critical that the following system conditions are accurately determined and/or calculated before the installation of any sectionalizing device: System configuration (line conductor sizes, number phases, voltages, opens and substation boundaries, substation feeder numbers and service areas, etc.); Location of critical loads (e.g., large power, large commercial and industrial plants, hospitals, schools, nursing homes); Available fault currents; and Peak line/load currents.

System configuration is demonstrated primarily from the mapping system. The mapping system provides information to help determine each of the above items. If the system is old and not adequately maintained, steps should be taken to update and field verify what the current electric system characteristics are. Geographic information systems (GIS) are available to help analyze electric system conditions and to aid in maintenance and management. This tool can be invaluable in the proper operation and maintenance of sectionalizing devices. In addition, GIS is constantly improving and, with improved communication techniques, live or real-time system monitoring can be attained, providing a means for quick responses to system outages and line problems.

In planning system protection and sectionalizing, knowledge of critical load locations is important. Sectionalizing devices are placed to eliminate exposure of critical loads, assuring minimized interruption and reliability of service.

Available fault currents are calculated from the source impedances as provided by the power supplier. Calculations of system conditions are based on this information, and the method for calculating such values is discussed earlier. The information should include, as a minimum, the positive-, negative-, and zero-sequence impedances on, typically, a 100 MVA base at a specified point on the electrical system (i.e., high side of a substation, low side of substation, or point on a distribution meter point).

Finally, the last critical aspect of the system that needs to be known is the line load currents. Often, such accurate information is the most difficult to secure. The reason is that the load currents vary with system conditions (i.e., summer, winter). Typically, the values are first calculated from a system computer model built around an accurate mapping system, accurate consumer load data, and accurate substation service area boundaries for the time of the load data. The calculated values and model should then be validated from actual field-recorded peak voltages and currents. Such values can be recorded from installed digital recording voltmeters at selected key line locations (e.g., circuit extremities with high voltage drops, key circuit branch points) and from digital line voltage regulator controls. From the field-measured values, the system peak model conditions can be validated for use in the design of the protection system and application of sectionalizing devices. It is extremely important that the model accurately reflect the realities of the system.

Location Selection

After a valid system model has been developed, the preferred and best location of the overhead line sectionalizing devices can be determined. Starting from the substation feeder device to the end of the circuit, the following guidelines can be utilized in the location of line sectionalizing devices:

- Identify any zones of protection.
- Locate priority loads and install sectionalizing devices down line to eliminate exposure and improve reliability.
- Identify key branch points and install devices such that service to the higher load branch or both branches can be maintained.
- Locate points on the distribution feeder where the minimum calculated fault conditions are below substation feeder minimum ground pickup level and install a suitable device at that location or up line.
- Install devices at locations that are easily accessible for operations.

- Locate taps off main lines that are either long, through wooded areas, or inaccessible.

Typically, sectionalizing devices are located on the electric system for primarily to eliminate line exposure for high loads or load groups (branch circuits), and to have enough devices on the system to aid in the location and isolation of faulted lines. This will enable system operating and construction personnel to restore electric service in a timely fashion. Following the guidelines listed above will enable the system engineer to accomplish these objectives.

After locating application points for reclosers, it is important to locate sites for the application of line switches. These points can be determined from the computer model and the mapping system. Sites where loads can be transferred to alternative sources should be identified and line switches installed to allow for easy transfer when line problems occur. The main purpose for the switches is to provide such operational flexibility, but also to provide visible breaks when line repairs are being made.

Once system conditions have been identified and validated with a computer model, and after locations have been selected to produce the desired operational results outlined above, the particular sectionalizing device can be selected. Typically, reclosers or sectionalizers are utilized on lines that have the highest loads, have the most customers, and justify the highest expenditures for reliability. Lines with the lowest loads and fewest consumers will use fuses. Reclosers and sectionalizers are also installed to aid in fault location and power restoration.

Line reclosers are the most expensive sectionalizing device, with single-phase sectionalizers being close behind, leaving fuses as the least expensive device. With such devices, the following conditions have to be met in selecting the type and size of the equipment.

- The device must have the insulation level suitable for the line voltage to which it is to be applied.

- The device must have the continuous current rating to carry the projected peak load conditions and any anticipated load shifts. The rating should be selected to allow for load growth over at least the next 3- to 5-year period.

- The device must be able to interrupt the maximum fault current calculated at the point of application.

- The device must respond to the minimum calculated line-to-ground fault to the end of the line or to the next down line device.

- The device must coordinate with down line devices.

- The device must coordinate with up line devices.

Insulation levels are usually based on rated withstand test voltage, which is expressed as basic impulse level (BIL) in kilovolts. The typical ratings for distribution equipment are 95 kV BIL for 12.5 kV systems, 125 kV BIL for 25 kV systems, and 150 kV for 35 kV systems. Equipment with higher BIL can usually operate on lower-voltage systems. Engineers are encouraged to coordinate such applications with the manufacturer before equipment installation to identify any limitations and operational problems.

Line devices also typically have overload factors identified by the manufacturers. If such factors have been identified by the manufacturers, short-term operation overloads can be allowed without serious damage occurring to or improper operation of the device. The system engineer is encouraged to be familiar with these overload factors before sizing any sectionalizing device.

One of the most serious mistakes in the application of sectionalizing devices is to install them at locations where they do not have the interrupting rating to clear the maximum calculated fault. Such actions can result in rupture of the device, possible fire on the pole and the ground, and possible injury of individuals who might be standing below the device or in the vicinity. It is important that the system engineer carefully apply sectionalizing devices so that they have the capacity to safely interrupt the maximum fault calculated.

Time-Current Curve Selection

Protective devices are said to be coordinated when the device closest to the fault location interrupts the line fault current without causing up line devices to permanently open or lock out. Coordination is achieved by proper selection of fuse size, trip coil ratings for hydraulic reclosers, or minimum trip current values in electronic and relay-controlled reclosers. The selection of the proper fuse size, trip ratings, or settings is determined by comparing the time-current curves (TCCs) of the up line and down line devices.

Time-current curves of fuses and hydraulically controlled reclosers are generally of similar shapes, which can simplify the coordination process. However, the limited selection of these curves can also make it harder to achieve the desired level of coordination. Relay-controlled and electronically controlled reclosers have a large variety of settings and can be closely coordinated with other devices, but the wide range of settings can make the process more complicated.

Coordination

Electromechanical or electronic relays are used with three-phase breakers in substations or other applications that require devices capable of interrupting high levels of fault current.

Electromechanical relays have several characteristics that must be considered for coordination with a down line device.

For time-delayed tripping, the relay contains a disk that begins moving toward the closed position when line current exceeds the relay's minimum trip setting. When the disk fully rotates, it closes a set of contacts that causes the breaker to trip. When timing for a fault current, the relay disk moves toward the closed position, and it will continue to rotate (coast) for a short time after it is de-energized if the fault is interrupted by a down line device. This additional rotation is called the *coasting time* or *impulse margin time*. The down line device must clear the fault in sufficient time to prevent the coasting action of the disk from causing the relay to unnecessarily trip.

Likewise, electromechanical relays typically do not reset immediately after de-energization because the disk requires time to return to its original position. If the down line device is a recloser, the relay disk may not have time to fully reset during the reclosing interval. Under this condition, the disk will accumulate, or advance its rotation, toward contact closure with each reclose action, also causing the relay to unnecessarily trip. Downline reclosers must allow a sufficient reclosing interval to allow the relay to reset, or allowances must be made in the relay settings to compensate for the accumulated disk travel.

One commonly overlooked characteristic of relay controlled devices is the control response curve associated with the interrupting device clearing time. The clearing time of the interrupting device (also called the *interrupting time*) must be added to the control response time to determine the average clearing time. Relay trip settings can be adjusted using current tap and time dial settings to produce a variety of time-current characteristics. Refer to the relay manufacturer's literature to determine the available settings, including the coasting and reset times, for the relay in question.

Electronically controlled reclosers are available for single- and three phase applications. They are commonly used not only in substations but throughout the distribution system. These devices can be coordinated closely with down line devices since there is no coasting or override in the electronic device. If the down line device, with its plus tolerance, clears faster than the response time of the electronic control with its negative tolerance, then the devices will coordinate. As with relay-controlled devices, the clearing time of the interrupting device must be added to the control response time to determine the average clearing time.

For coordination with down line devices, it should be understood that when the control response curve of an electronic control is exceeded, the interrupting device has been committed to trip, regardless of the total clearing time. Thus, control response curves of both fast (instantaneous) and time-delay curves should be compared with down line sectionalizing device operating curves. As an example, the control response curve, including tolerance of the time delay curve, must lie above the maximum clearing curve, including tolerance, of a load-side recloser or fuse if coordination is required.

When an electronic recloser is coordinated with an up line device, the clearing time of the interrupting device must be added to the control response time, plus tolerances, to check coordination with the up line device. Clearing times and TCC tolerances are usually listed on the manufacturer's TCC sheet for the device.

Reclosing intervals and resetting intervals may require coordination with other devices in applying electronic reclosers. When the recloser is used down line of a fuse, for example (in a substation application), the reclosing time may need to be lengthened to allow fuse cooling between recloser operations.

The simplest method of coordinating reclosers in series is to choose the same make and style of recloser and then to select reclosers in descending coil sizes. Usually, adjacent coil sizes will coordinate satisfactorily if the reclosers are not spaced too closely. However, if load current or fault current at the substation is high, it may be uneconomical to use the higher-interrupting-rated recloser throughout the entire circuit. When reclosers of different make or type are used in series, it will be necessary to plot the time-current characteristic (TCC) curves of each recloser in order to determine coordination.

Coordination by merely selecting adjacent coil sizes can frequently be achieved with hydraulic reclosers of different make or type. However, this should be checked by comparing TCC curves. The fast curves may have different slopes and speeds but, in most cases, it is usually not possible to coordinate fast curves on hydraulic reclosers.

When comparing TCC curves of adjacent reclosers, it is important to maintain sufficient separation between the curves to avoid simultaneous operation of the two devices. Generally, separation of less than 2 cycles will result in simultaneous operation; separation of 2 to 12 cycles *may* result in simultaneous operation; and separation of more than 12 cycles will assure coordination.

It is possible to coordinate series reclosers by electing different time-delay operating curves or a different number of operating sequences. This generally is not recommended, however, except in special cases where coordination cannot be achieved otherwise. It is good practice to standardize on a particular time-delay curve and operating sequence for all line reclosers on a system. (This does not necessarily apply to substation reclosers. The demanding requirement of substation protection and coordination can often be met by special selection of curves and sequences for each station or feeder.) Experience has indicated that a sequence of two fast curve operations followed by two time-delay curve operations followed by lockout is a good choice for line reclosers. However, some system operators may wish to standardize on one fast and either two or three time-delay curves. In high-lightning incidence areas, it may be advantageous to use three fast curves followed by a time-delay curve.

Coordination of reclosers with source-side fuse links is most often encountered when the fuse is protecting the high-voltage side of a transformer and the recloser is on the low-voltage side.

To coordinate the recloser with an up line fuse, the cumulative heating effect of the recloser operations must be less than the minimum-melting curve (or damage curve) of the fuse. The time value of the recloser delayed curve is multiplied by a heating factor (also called the *K* factor) to account for the heating effect. The *K* factor will vary with the reclose timing and the fast-slow sequence of the recloser.

Coordination of reclosers with load-side fuse links is usually done to permit the recloser to clear temporary faults beyond the fuse and to force the fuse to blow on permanent faults. This is commonly referred to as "fuse saving." Coordination is determined by plotting the time-current curves of both the recloser and fuse. As previously discussed, the reclose operations of the recloser will cause heating in the fuse, therefore the time value of the recloser's fast curve must be shifted to account for the heating effect.

If only one fast curve is used on the recloser, a 1.25 multiplying factor is used. If two fast curves are used, a 1.35 multiplier is used for reclose times of 60 cycles or longer and a 1.8 multiplier for reclose times less than 60 cycles. Both fuse curves, minimum melt and maximum clearing, should be plotted. The fuse curves should lie between the shifted fast curve and the time-delay curve over all or most of the range of available fault current.

Tolerance should be allowed for recloser time-delay curves. Because of the shape of the curves, it may not be possible to achieve perfect coordination over the entire fault current range. In general, EEI-NEMA Type T fuse links provide the widest range of coordination with hydraulic reclosers.

It is desirable to employ recloser fuse combinations that will allow the recloser to sense a minimum calculated fault at the end of the line. However, if this is not practical, the fuse should melt for an end-of-the-line minimum fault in approximately 20 seconds or less.

Many branch lines can be most economically protected by fused cutouts. It is desirable that they be coordinated with and protected by reclosers as previously described. It is sometimes practical to apply, in series, two fuse links with different ratings protected by one recloser. At other locations, it may be more economical to provide only permanent fault protection by coordinating fuse links in series. It is best to limit the number of branch line sectionalizing fuses in series to two or three. It is recommended that the same make or type fuse link be used throughout a system.

When coordinating sectionalizing line fuses in series, the following factors should be considered:

- Peak load currents at the point of application should be less than the fuse link rating. The fuse link must be large enough to withstand inrush currents to motors, capacitor banks, and transformer banks. In addition to these transients, which last only a few cycles, consideration should be given to cold-load pickup, which can last several seconds to several minutes. Some fuses are rated for a higher continuous current than the name might suggest. Therefore, it is important to consult the manufacturer's specifications regarding fuses.

- The fuses should be coordinated with each other by applying the 75% rule. This means that the loadside fuse maximum clearing curve should not exceed 75% of the source-side fuse minimum melting curve.

- The fuse links should be coordinated with the burndown characteristic of the conductors in the fuse zone of protection.

- A fuse link should melt in approximately 20 seconds or faster for a minimum fault in its zone of protection.

Identification of High-Reliability Zones

Because of the widespread use of microprocessor-based devices in homes and businesses, consumers are highly sensitive to the momentary outages that occur during recloser operations. These outages can cause clocks to reset, digital controls to malfunction, and computer systems to crash. Although recloser operations are a normal, and necessary, part of the protection scheme, many consumers find them objectionable and will begin to question the reliability of the electric system if they occur too frequently.

To increase the reliability of a particular feeder, efforts must be made to decrease the number of momentary outages affecting the circuit. However, down line reclosers or fuses can cause the up line main feeder recloser to operate on its fast curves before the down line device clears the fault. These additional operations increase the number of momentary outages and decrease the reliability of the entire down line circuit. Therefore, a high-reliability zone can be established beginning with the substation feeder recloser and extending down line to the first mainline recloser.

To begin establishing a high-reliability zone, the substation protection device should utilize an electronic control with sequence coordination features. *Sequence coordination* enables the recloser to suppress its fast-trip operations in response to a fault beyond a down line recloser. All taps in this zone need to be protected by a fuse or recloser. The substation fast trip curves and all tap fuses should be coordinated to cause the fuse to blow before the recloser trips on its fast curve. This scheme is known as "trip-saving," as opposed to the fuse-saving scheme. A trip-saving scheme will cause a permanent outage on the tap for faults beyond the fuse, but will not cause the up line recloser to operate.

Another tool available for use in a high-reliability zone is the single-phase electronic recloser. These devices are available with sequence coordination, and can be configured for single-phase trip with three-phase lockout, single-phase trip with single-phase lockout, or three-phase trip with three-phase lockout. Because these devices can operate in single-phase mode, faults affecting one or two phases will not cause momentary outages on the unaffected phases, resulting in better overall reliability.

This high-reliability zone concept can be extended out on the feeder. As noted, it will require use of electronic reclosers capable of sequence coordination and careful selection of recloser trip curves and fuse curves to achieve trip-saving coordination.

Guidelines for Underground Overcurrent Protection

If a circuit is completely underground, it should be assumed that there can be almost no temporary faults on that circuit. Therefore, there is little justification for automatic-reclosing overcurrent protective devices for the purpose of clearing temporary faults. Reclosing on an underground fault can worsen the damage to the faulted cable and can conceivably damage a sound adjacent cable. A one-shot sectionalizing plan using fuses, fault interrupters, or a combination of both can be considered, provided selective coordination of the devices in series can be attained.

Fusing is the best solution for many underground sectionalizing applications with relatively few consumers and/or lower load current. However, for higher loads and larger numbers of consumers, pad- and pole-mounted electronic fault interrupters offer a good alternative to fusing. As electronically controlled devices, these units offer a wider range of coordination than fuses. In addition, if ferroresonance is anticipated, or if single phasing of three-phase loads would be a problem, electronic three-phase fault interrupters can be used. A combination of fuses and fault interrupters is certainly a possibility for an all-underground sectionalizing plan.

If coordination between fuses or older-style non-electronic one-shot devices cannot be assured because of load current or fault current conditions, consider the use of electronic fault interrupters or use electronically controlled reclosers set to one-shot operation. As previously stated, these devices offer much more flexibility than do fuses or hydraulically controlled sectionalizers. If electronic fault interrupters or reclosers are not available, and coordination must be achieved, consider using a hydraulic recloser. In this case, the reclosers would not be used for the purpose of clearing temporary faults, but instead would be used to assure selective coordination of sectionalizing devices.

While it is true that reclosing on an underground fault can exacerbate the damage to a faulted cable and can conceivably damage a sound adjacent cable, it is felt that an overriding consideration is to selectively sectionalize the smallest section of cable, thereby rendering better service to consumers. The general rule of thumb is that it is not necessary to reclose on an underground fault. However, if in the judgment of the engineer, better service reliability to the most consumers can be expected by choosing an automatic reclosing device, it is preferable to do so. The number of reclosing operations should be held to a minimum. Usually one or at most two reclose operations will be all that will be required for coordination with other devices.

Circuits with both overhead and underground construction present different sectionalizing problems than either a total underground circuit or a completely overhead circuit. It is not unusual for circuits to exit from a distribution substation with underground cable. The underground exit may extend for several hundred feet or for several miles before it reaches an overhead transition point. Overhead distribution circuits can also dip underground at any point and reemerge again to continue as an overhead line.

Considerable engineering judgment should be exercised in selecting sectionalizing devices for these combination lines. If the majority of the line is underground with a small percentage overhead, the line can be considered similar to an all-underground circuit. The converse is also true. If the line is predominately overhead with a small part of it underground, it can be considered as a completely overhead system in choosing overcurrent protective devices.

It is usually not possible to install fuses between reclosers, although it may seem desirable to do so in certain overhead/underground circuits. An attempt to do this usually results in fuses and reclosers being larger than would ordinarily be selected. This, in turn, results in the entire coordination of time-current curves back to the substation being undesirably high.

A three-phase automatic line sectionalizer can be installed between three-phase reclosers, provided the sectionalizer is equipped with the sensing required to permit it to count only the backup recloser operations. This is sometimes described as “voltage restraint.” The advantage of a sectionalizer is that it does not operate on a time-current curve. The disadvantage of a sectionalizer is that it would probably be set for one count and is, therefore, a high-cost device compared to a fuse. If the expense of three-phase sectionalizers and three-phase reclosers cannot be justified, the alternative is to treat the underground section of line as if it were an overhead line.

Underground taps off main overhead lines usually present no unusual overcurrent coordination problems. They can be economically fused. If coordination with fuses cannot be achieved, consideration should be given to electronic fault interrupters.

Although underground cable faults are usually rare occurrences, the time required to locate, switch lines, or repair the cable can result in an extended outage for the consumers. The proper use of faulted circuit indicators (FCIs) will enable quick identification of a faulted cable section and significantly reduce outage time. The FCI is easily affixed to the cable or elbow, and contains a sensor that causes a built-in target or indicator to operate when current exceeds a preset level. Operating personnel can quickly check each FCI on the circuit to determine the last point at which fault current was detected. Using this information, they can then isolate the faulted section and begin restoration work.

FCI devices should be placed along the circuit at strategic points that will allow operating personnel to determine the location of the faulted section and switch lines to restore service to the maximum number of consumers. The number and cost of placement of the FCI devices along a circuit should be weighed against the number of consumers and level of desired reliability.

A number of manufacturers produce FCI devices in a variety of configurations for overhead and underground use. FCIs are generally selected according to load current levels and reset methods. Devices can be reset manually, or configured for time delay, voltage, or current reset. Most FCI manufacturers provide detailed application notes for their products. Take advantage of this information to achieve the best results from these devices.

Chapter 5
Special Considerations

As previously mentioned sectionalizing and system coordination is more an “art” than a “science”. This chapter discusses various factors other than just fault current that should be considered in a sectionalizing scheme.

Critical Loads

The load served by a distribution system often affects not only the mechanics of system protection but also the sectionalizing philosophy. Critical loads such as health care, emergency response, communications, and other infrastructure services require special consideration to minimize the chance for outages. Although it is not always physically or economically feasible, distribution system protection devices should be located down line of critical loads. Although modern motor controls monitor and protect for the loss of one or more phases, consideration should be given to using three-phase or gang-operated devices for critical three-phase loads to prevent damage to customers’ equipment.

Cold Load Pickup

Cold load pickup refers to the restoration of loads that have been unserved for some time period. Cold load pickup typically is divided into two types: inrush controlled and thermostatically controlled. Inrush currents result from a number of factors, such as distribution transformer energization, motor starting currents, and motor accelerating currents. These inrush currents can easily last several cycles and exceed nominal load currents by up to 10 times. Thermostatically controlled cold load pickup is the increase in load due to increased heating or cooling loads, such as air conditioning, heating, and water heating. Inrush cold load pickup is the primary relaying consideration.

When fast curves or operations are used in system protection schemes, nuisance trips are not uncommon. Generally, inrush currents will stabilize within a few cycles, and even in the event of a fast curve trip and reclose, the sectionalizing device will generally reclose successfully when it utilizes the slow curve. Some electronic reclosers support operator enabled cold load pickup, which simply advances the control to the slow time-current curve. More advanced relays may utilize harmonic analysis (typically second and third harmonics) to identify inrush currents and suppress trips due to inrush. Although this type of relay is more prominent in substations’ transformer protection relays, newer intelligent devices have the ability to perform a similar function.

Cold load pickup due to thermal recovery and loss of diversity of heating and cooling systems can remain from a few minutes to several hours, and can easily reach 3 to 5 times normal load currents. These increased load levels, due to the loss of diversity, often require incremental load pickup. Although this method extends outage times, it provides better protection than increasing trip settings or bypassing sectionalizing equipment.

Load Imbalance

Maintaining a well-balanced load is a never-ending challenge, particularly in rural areas served by long single-phase lines. Seasonal loading can also complicate maintaining good load balance. Although electricity is often the most practical cooling method, efficient and cost-effective heating may be accomplished a number of ways. In climates where customers can use either gas or electricity for heating, loads can swing from balanced to imbalanced each season, depending on the distribution and location of the electric and nonelectric loads. Frequent monitoring of load imbalances at major sectionalizing points is important to detect potential problems. Ground relays are one of the best ways to detect high-impedance phase-to-ground faults. Consequently, the better balanced the load, the lower the neutral current and the more sensitive the ground relays can be set. At the same time, consideration must be given to the load imbalance resulting from single-phase sectionalizing. Keeping single-phase loads as small as possible is ideal, but is simply not economically feasible or practical in all cases. Another consequence of load imbalances is inrush currents. In the case of a load imbalance that causes only 40 amperes of neutral current, an inrush situation may cause five times that amount for several cycles. This resulting 200 Amps of neutral current could easily operate a 180-Amp fast curve. Herein lies the "art" of system protection: finding a practical compromise between reliability and protection.

Sympathetic Tripping

Sympathetic tripping may be a factor in protection analysis, particularly on weak or higher-impedance systems. Sympathetic tripping typically occurs at substations where protective devices are on the same bus. If a high-current fault occurs on a feeder served by a high-impedance source, the bus voltage drops proportionally to the fault current and system impedance. In some cases, the load can respond to the lower voltage with higher currents, exceeding the trip values set in the protective relay. Newer protection analysis software can calculate voltages throughout the distribution system for a given fault type and location, which can help quantify expected voltages for given faults. However, the load's response to the lower voltage depends highly on the type of load. A purely resistive load would have a decreasing current with a decreasing voltage, while motor loads would typically respond with higher currents as they attempt to do the work with less voltage.

Tripping and Reclosing Practices

Electric distribution systems have typically utilized three reclosures to lockout (or four trips to lockout). This has been for substation feeder circuit breakers or reclosers as well as line circuit reclosers. If substation feeder circuit breakers were used, instantaneous reclosure was utilized after the first trip. Time-current characteristics for recloser tripping have typically been two fast operations and two slow operations. Over the years, such practices have been evaluated and scrutinized. The results show that changes appear to be warranted.

According to a paper presented by the Power System Relaying Committee of the IEEE Power Engineering Society, the practice of allowing instantaneous reclosures and four trips to lockout on substation circuit breakers is not a sound sectionalizing practice and, in fact, is detrimental to system operations. The study concluded that:

With instantaneous reclosure on a circuit breaker, often the breaker closes back into a temporary faulted line condition before the fault clears itself, and

- The third reclosure is generally unsuccessful, contributing to unnecessary through faults on substation power transformers and should be eliminated.

- On the basis of the conclusions made in this study, the practice of having instantaneous reclosures on substation distribution feeders is not recommended. Also, it is strongly recommended that all substation feeder breakers or reclosers have only two reclosures to lockout (or three trips to lockout).

As mentioned earlier, with the use of digital electronics there has been a trend to reduce feeder operations by eliminating the fast TCC response and allowing the down line fuses to clear the fault lines. This concept removes any fuse-saving policy, deferring to the elimination of nuisance—and often frequent—operations of substation feeder breakers or reclosers. This practice is in line with the high-reliability zone policy mentioned above.

Voltage Conversions

Many utilities continue to increase system voltages, primarily to serve increasing loads with existing conductors, with the added benefit of reducing losses. Voltage conversions typically double system voltages, such as a conversion from 12.47 kV to 24.94 kV.

Only in rare instances can an entire feeder be converted to a higher voltage. Therefore, step transformers are often used to convert portions of a feeder. Often, voltage conversions occur over several years, so step transformers are an integral part of the distribution system. Most often voltage conversions start at the substation and extend down line over time. However, some situations—such as very long single-phase lines with loading near the end—may be best served by a voltage conversion at the load end of a line rather than the source end.

While higher operational voltages lower load currents and increase fault currents, the values don't always double or halve as expected. Some utilities specify step transformers with higher impedances to reduce through-fault currents, thereby increasing system impedance and further reducing fault currents. Analysis software becomes very important when developing protection schemes on mixed voltage systems. The following example shows why. A 25-kV feeder with a 40-ohm ground impedance would result in a minimum phase-to-ground current of 360 amps. On the 12-kV (load) side of a step transformer, the minimum phase-to-ground current in the 12-kV area would be 180 amps. However, if a protective device is located in the 25-kV area, but its protection zone extends into the 12-kV area, the device will only see half of the 180-amps minimum fault current in the 12-kV area, or 90 amps. Although it may be intuitive that the minimum fault current for a 25-kV sectionalizing device (with a 40-ohm fault impedance) is 360 amps, if its protection zone includes, and extends beyond, a step transformer, the minimum fault current it needs to detect and clear is actually only 90 amps. Similarly, where a step transformer is used to step up rather than down, the minimum source (12-kV) fault currents increase when the fault is in the higher voltage (25-kV) area.

Programmable Logic Control

Many programmable sectionalizing devices now contain some form of programmable logic control (PLC). The electronics can be as simple as user-selectable time-current curve (TCC) selection and programmable time delays, or as complex as user customized TCCs, thereby allowing better coordination responses.

Beyond simple data entry of settings, many devices also support ladder logic or logical equations to control sectionalizing devices' tripping schemes. Although somewhat more complicated than electromechanical devices, these devices provide many more options to protection engineers. In the most extreme applications, the combination of PLC-type programmability coupled with remote communications can yield a very dynamic and flexible protection system for increasingly complex distribution networks. Even in the simplest radial applications, user defined TCCs may allow the protection engineer to move from a lockout coordination to a trip coordination scheme while utilizing a combination of older hydraulic devices and newer programmable electronic devices. Programmable logic can also be used to set up and configure sequence-of-events recorders or load interval data logging.

Alternative Settings

Alternative settings are, as the name implies, an alternative set of tripping set points. They are most useful when a device may be operated in multiple scenarios. A common and simple application of alternative settings is in a substation feeder relay or recloser that could serve as a secondary source to predetermined critical load. In the event the primary source to the critical load is lost, the backup feeder may be required to serve the load.

It is likely that, in many cases, the secondary source device's setting would be too low and would require an increase in trip currents to serve both normal and contingency loads. Using alternative settings is a method by which the protection engineer can "pre-engineer" settings for known contingency cases, while simplifying the tasks of field personnel. Another application of alternative settings is providing seasonal settings where load variations dictate. The alternative trip settings are a field-selectable control that relieves the protection engineer from having to reprogram field devices.

Fault Data

Obviously, the magnitude of fault currents during an event is important to the protection engineer for a number of reasons. Fault magnitudes, in combination with fault location from operations personal, and other system configuration parameters can help validate the accuracy of the engineering model used to perform the protection study. Higher-end devices can also perform waveform captures, which allow an even more detailed analysis by defining the exact cycle level timing of a fault as well as protective equipment response times. The former allows analysis of the symmetrical and asymmetrical contribution to the fault as well. Probably the most useful application of fault data is the analysis of duty cycles. Equipment duty cycles are the primary driver of performing maintenance. Many of today's smarter devices can be programmed to record duty cycle information and indicate to the operator when a particular device is nearing time for maintenance. Analysis of duty cycles provides the opportunity to perform more cost-effective, just-in-time maintenance rather than cyclical or reactive maintenance of protection equipment.

Load Data

Load data is another component of the sectionalizing and coordination equations. Load data collected by *Intelligent Electronic Devices* (IEDs) can be used not only for coordination studies, but also for system planning studies. Load interval data collection should be configured at the device level to support access to this data for the various engineering studies. Some legacy devices may store only 24 hours of data, while newer devices can store several months of data, depending on what metered values are configured. In general, most devices can monitor and record maximum currents, while many now support voltage inputs in addition to the currents, which allows meter quality data collection of parameters, such as power, reactive power, and power factor with a single device. The voltages can also be used to increase the functionality of the protective device by providing under- or overvoltage protection or even single-phasing protection of down line equipment.

Distribution Automation

With the advent of lower-cost communications, better standardization of communication protocols, and more-intelligent sectionalizing devices, much more sophisticated protection schemes can be developed. Although distribution automation can improve the performance from the protection perspective, it is perhaps more important in providing the ability to provide automatic restoration to critical loads. Very often, distribution automation can be cost-justified only in high-density or high load-factor areas. Availability of alternative power sources, as well as communications systems, is often a limiting factor as well.

Transfer Trip Schemes

Transfer trip schemes are often used in multisource environments. They are used primarily when a protective device needs to ensure than an alternative source or distributed resource has been isolated. Transfer trip schemes can also be utilized as a backup protection scheme under breaker failure modes of operation.

In a distribution network, the availability of communications and the signal latency become important design considerations. Dedicated fiber optics is the ideal communication medium; however, other communication technologies have been used successfully in recent years.

Flip-Flop Schemes

Flip-flop schemes are most often used for critical load applications. When two sources are available to a critical load and the primary source is lost, the primary source can be isolated, allowing the load to be switched to the secondary source. Very often, the equipment used to isolate one source and switch to the other source has to be located in close proximity. However, with the advent of improved communications and a larger installed base of fiber optic communication cables in municipal areas, this equipment may be installed farther apart.

Fault Location

There are a number of ways to perform fault location. The traditional method has been to use mechanically activated devices installed on the primary conductor that trigger or trip a target when a predetermined current is exceeded. This method has been used on transmission and distribution systems for years. Fault locators can often be used successfully in a system protection scheme, especially to minimize patrol times, particularly in challenging terrain. In transmission systems, lines are generally long and made of the same type conductor for many miles. Therefore, line impedance is very predictable as a function of distance from the source or protective relay. Distance relays have been used successfully for many years on transmission lines to locate faults.

However, distribution networks have a multitude of taps and varying sizes of conductors in most areas, thereby making the line impedance—and, therefore, fault current—the same at many locations on the same feeder. This would result in multiple possible targets for a fault.

Today there are several varieties of both mechanical and electronic fault locators. The biggest drawback to mechanical devices is the predefined "setting," or trigger levels, which limit the application of the devices to certain load and fault conditions. Mechanical locators also occasionally give false positive and false negative indications because of such things as improper sizing, inrush currents, and double faults (one fault causing another fault). The advantages of mechanical devices are lower cost and virtually no maintenance.

There are a few electronic fault locators on the market. They vary from replacements for mechanical locators to expensive IEDs capable of load interval and waveform capture in addition to local and remote fault indications. Vendors claim that the electronic devices are more accurate than mechanical devices and give 10+ years of maintenance-free service.

Distributed Generation

The popularity of distributed generation (DG), or distributed resources (DR), is increasing because of technological advances, system benefits, and economic improvements in the cost of connecting such systems to the distribution system. Installing DG will have an impact on the distribution system, and special provisions should be made for it. A thorough analysis of DG systems and their impact on distribution systems is in IEEE Standard 1547, *Standard for Interconnecting Distributed Resources with Electric Power Systems*.

The addition of DG will affect the coordination of a distribution system, depending on the DG size, configuration, and location, as well as the location of up line and down line protective devices. DG should be considered as a second source to the distribution system, potentially resulting in higher fault currents and two-way power flow. Modifying the coordination of protective devices to support the higher fault currents may result in overreaching devices, thereby increasing the outage exposure to the existing distribution system. Bidirectional power flow devices can be also utilized to optimize the coordination; however, the addition of these devices and their associated components may be cost prohibitive for the utility and/or DG owner.

Depending on the DG location, size, and local protection equipment, this second source could serve as a hazard to utility maintenance personnel by backfeeding the distribution system during planned or unplanned outages. It is recommended that a means of disconnecting the DG from the distribution system be required so that the DG can be isolated during maintenance or restoration activities by utility personnel.

Islanding of the DG can result when the up line protective device operates, isolating the circuit so that the DG serves the load normally fed by the distribution system. Damage to equipment may result should the up line protective device reclose out-of-synch with the DG. To address these issues, provision should be made to remove the DG from the distribution system automatically on operation of an up line protective device. Many smaller DG systems such as residential photovoltaic systems integrate islanding protection as a part of the inverter design.

Chapter 6
Design Example Problem

We will finish this course with a sample problem that illustrates a method to sectionalize the system of a 15MVA substation. For simplicity, only one feeder will be sectionalized. The configuration developed in this example is not the only way the system can be sectionalized; the particular method will depend on the preferences and experiences of the engineer, circuit configuration, and the historical preferences of the utility.

To get the greatest long-term benefit out of the sectionalizing study, the load current calculations for each feeder are based on the projected peak load of the substation. The system and estimated loads are shown in Figure 4.

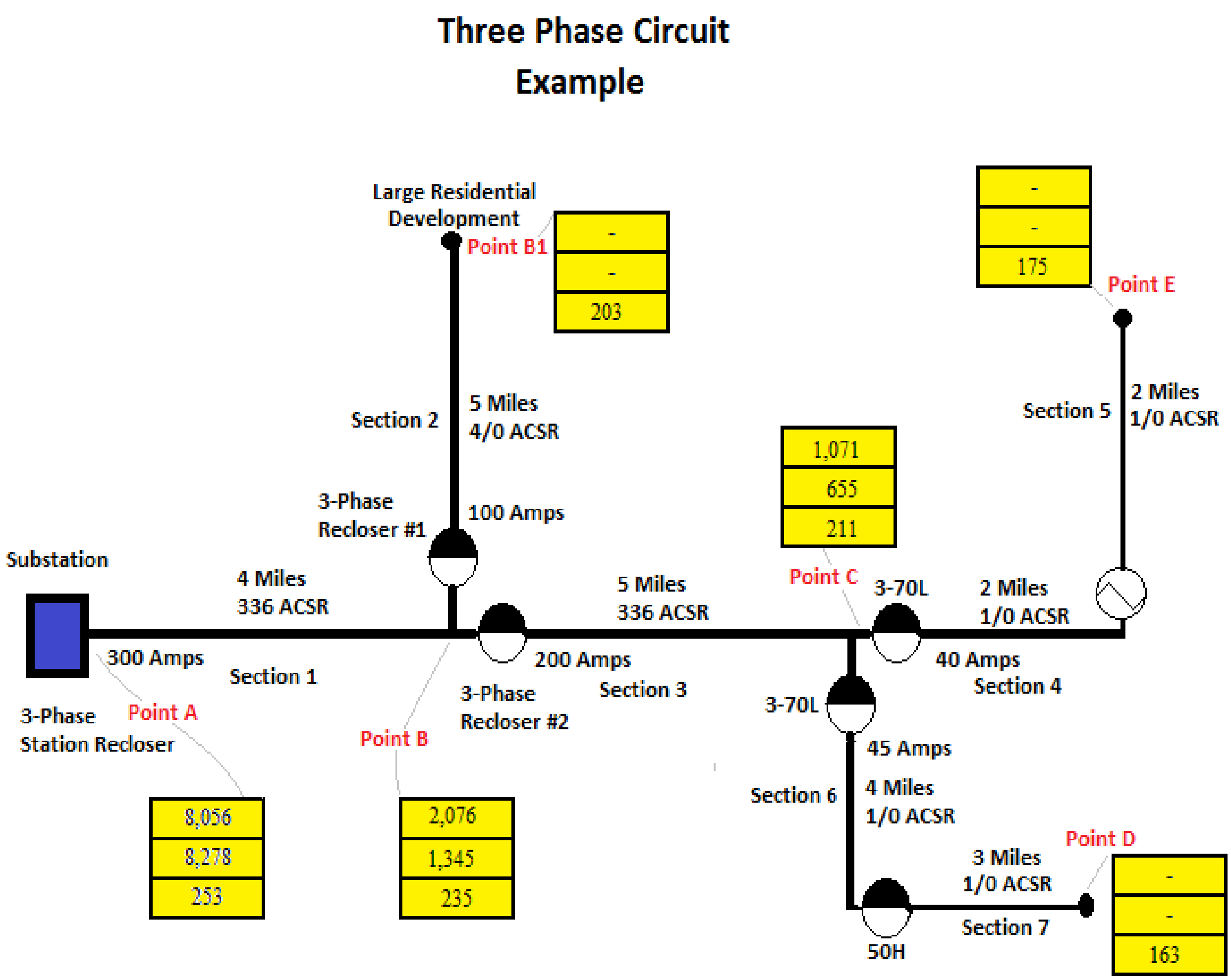


Figure 4

Basic Data

The first step is to gather the base data for the analysis. The power supplier to the substation provided the following information about the source:

$Z_1 = Z_2 = 0.14 + j4.39\%$ on 100 MVA base
$Z_0 = 3.44 + j14.65\%$ on 100 MVA base

The following information is supplied by the transformer manufacturer or is obtained from the transformer's nameplate:

Capacity: 15 MVA
High side Voltage: 100 kV
Low side Voltage: 13.2/7.62 kV
Impedance: 7.45%

Calculation of Substation Fault Currents

Maximum fault current is calculated at each proposed sectionalizing location. Minimum fault currents are calculated for each device at the end of the section of line the device is designed to protect, i.e., device's zone of protection.

The three-phase transformer impedance can be converted using the per unit method:

$$Z_t = \frac{100\ MVA}{15\ MVA} * 7.45\% = 49.667\%$$

In this example, we will make an assumption to spread the transformer into its resistance and reactance components by using the approximation 0.1 + j1.0.

Thus the transformer impedance becomes:

(49.667%)(0.1 + j1.0) = 4.9667 + j49.667% on 100 MVA base

Remember, the three-phase transformer impedance may also be calculated using the following formula to obtain the value in ohms,

$$\mathbf{Z(t)} = \frac{\mathbf{Z(t)\% * V_{LG}^2}}{\mathbf{kVA_{Phase} * 100,000}}$$

$$Z(t) = \frac{7.45 * 7{,}620^2}{5{,}000 * 100{,}000}$$

Z(t) = 0.8652 Ohms

For the purposes of this example, we will use the percent values.

Three-Phase Low Side Fault Calculation

Source Impedance Z_1 = 0.14 + j4.39% on 100 MVA (High Side)

Transformer Impedance Z_T = 4.9667 + j49.667% on 100 MVA Base

Adding the impedances,

0.1400 + j 4.390
4.9667 + j49.667
5.1067 + j54.057

Therefore, the low side source impedance is,

Z_1 = 5.1067 + j54.057 % on 100 MVA Base

$Z_1 = \sqrt{5.1067^2 + 54.057^2}$

Z_1 = 54.2976% on 100 MVA Base

Next, we need to calculate the Base Amps from the equation in Table 4,

$$\textbf{Base Amps} = \frac{\boldsymbol{Base\ MVA}}{\boldsymbol{V_{LL} * \sqrt{3}}}$$

Base Amps = $\frac{100}{13.2 * \sqrt{3}}$

Base Amps = 4,374 amps.

$$\text{Three Phase Low Side Fault} = \frac{100}{54.2976} * 4{,}374 = 8{,}056 \text{ amps.}$$

Single-Phase Low-Side Fault Calculations

Single-Phase Fault Impedance, $Z_{LN} = \frac{(2Z_1+Z_0)}{3}$

Source Impedance Z_1 = 5.1067 + j54.057 on 100 MVA Base

The low-side zero-sequence impedance is,

Transformer Impedance Z_0 = 4.9667 + j49.667 on 100 MVA Base

Total Low-Side Impedance = (15.1801 + j157.781) / 3 % on 100 MVA

= 5.060 + j 52.5937

= $\sqrt{5.06^2 + 52.5937^2}$

= 52.8366%

Again, using the base amps of 4,374 amps, we have,

$$\text{Single} - \text{Phase Maximum Low Side Fault} = \frac{100}{52.8366} * 4{,}374 = 8{,}278\ \text{amps.}$$

Distribution Line Impedance

The last impedance to be calculated is the distribution line impedance. To determine the impedances for three-phase faults, refer to the tables in Chapter 2.

Multiply each of the values obtained from the appropriate table by the number of feet or miles of each conductor size from the substation to the protection device or the end of the circuit as shown in the example below.

The line impedance calculation is generally performed by the engineering analysis model. Since the way the impedance model is calculated, there can be differences from the traditional line impedance calculations shown in references, and more modern impedance models that take into account the inductive and capacitive coupling using various matrix manipulation methods.

Table 6 shows the impedance values for each section of line shown in Figure 4.

Table 6 Line Resistance and Reactance Values						
Section	**Type**	**Dist (mi)**	**R**	**X**	**R**	**X**
A-B Wire	336 ACSR	4	0.278	0.632	1.112	2.528
B-B1 Wire	4/0 ACSR	5	0.441	0.712	2.205	3.560
B-C Wire	336 ACSR	5	0.278	0.632	1.390	3.160
C-D Wire	1/0 ACSR	7	0.885	0.756	6.195	5.292
C-E Wire	1/0 ACSR	4	0.885	0.756	3.540	3.024

Using the information from Table 6 along with the previously determined source and transformer impedances, we can find the three-phase, single line-to-ground, and minimum fault currents at each point on the circuit shown in Figure 4.

Calculating the fault current, I_f, is a simple matter of summing up the respective impedances vectorially from the fault location back to the source using the following equation:

$$\mathbf{I_{Fault}} = \frac{\boldsymbol{V_L}}{\sqrt{\left(\left(\boldsymbol{R_s}+\boldsymbol{R_t}+\boldsymbol{R_{Dist}}+\boldsymbol{R_f}\right)^2+\left(\boldsymbol{X_s}+\boldsymbol{X_t}+\boldsymbol{X_{Dist}}\right)^2\right)}}$$

When calculating the maximum fault current, assume $R_f = 0$. When calculating the minimum fault current, use the assumed value for fault current resistance, R_f. It has been assumed that the R_f is 30-40 ohms. For this example problem, we will use 30 ohms.

Generally, on three-phase lines, only the three-phase and single phase fault currents need to be calculated, since a line-to-line fault usually will result in neither a maximum or minimum value. However, on V-phase lines, the line-to-line fault will yield the maximum value at some distance away from the substation and should be calculated.

For the three-phase fault calculations, the source and transformer value is,

$Z_1 = 5.1067 + j54.057 = 54.2976\%$

For the single-line to ground and minimum fault current, the source and transformer value is,

$Z_0 = 5.060 + j52.5937 = 52.8366\%$

For the line section from Point A to Point B, the calculations are performed as follows.

First, the per unit impedance base is found,

$$Z_{pu} = \frac{13.2^2}{100} = 1.7424$$

Then, the source impedance is converted into ohms. We previously found the source impedance to be 5.107 + j54.057%.

$$R = \frac{5.107}{100} * 1.7424 = 0.089 \text{ Ohms}$$

$$X = \frac{54.087}{100} * 1.7424 = 0.942 \text{ Ohms}$$

From Table 6 we know that the conductor impedance for 4.0 miles of 3-phase, 336 ACSR is,

R = 1.112 Ohms

X = 2.528 Ohms

Adding the wire impedance to the source impedance we have,

Source	0.089 +j0.942
Line A-B	1.112 +j2.528
Total	1.201 +j3.470

Therefore,

$$Z = \sqrt{1.201^2 + 3.470^2}$$

Z = 3.67 Ohms

We can now find the three-phase fault current at point B,

$$I_{3\text{-Phase}} = \frac{13.2*1000}{\sqrt{3}*3.67} = 2{,}076 \text{ amps.}$$

For a single-line-to-ground fault, the same process is used, except the line resistance and reactance values are multiplied by the square root of 3 (1.732). In this case the resistance and reactance values are,

R_{dist} = 1.112 * 1.732 = 1.93 ohms

X_{dist} = 2.528 * 1.732 = 4.38 ohms

We need to convert the Z_0 source impedance into ohms just as we did with the Z_1 source impedance. The Z_0 source impedance was found to be Z_0 = 5.060 + j52.5937%.

$$R = \frac{5.060}{100} * 1.7424 = 0.084 \text{ Ohms}$$

$$X = \frac{52.5937}{100} * 1.7424 = 0.916 \text{ Ohms}$$

Adding the wire impedance to the source impedance we have,

Source, Z_0	0.084 +j0.916
Line A-B	1.930 +j4.380
Total	2.014 +j5.295

Therefore,

$$Z = \sqrt{2.014^2 + 5.529^2}$$

Z = 5.665

$$I_{SLG} = \frac{13.2*1000}{\sqrt{3}*5.665} = 1{,}345 \text{ amps.}$$

The minimum single-line-to-ground fault current is found in a similar fashion, except the 30-ohms minimum resistance is added to the impedance,

$$Z = \sqrt{(30 + 2.014)^2 + 5.529^2}$$

Z = 32.6

$$I_{SLG\ Min} = \frac{13.2*1000}{\sqrt{3}*32.6} = 235 \text{ amps.}$$

The remaining sections are determined in a similar fashion. Note that the impedance values are cumulative from the substation to the point of the fault. Table 7, below, summarizes the fault values for the entire system shown in Figure 4.

Table 7
Sample Problem Fault Values

Point	Three Phase Fault				Single Line to Ground Fault				Single Line to Ground Minimum Fault			
	R	**X**	**Z**	**Amps**	**R**	**X**	**Z**	**Amps**	**R**	**X**	**Z**	**Amps**
B	1.201	3.470	3.672	**2,076**	2.014	5.295	5.665	**1,345**	2.014	5.295	32.449	**235**
B1	3.406	7.030	7.812	**976**	5.833	11.461	12.860	**593**	5.833	11.461	37.621	**203**
C	2.591	7.118	7.118	**1,071**	4.422	10.768	11.640	**655**	4.422	10.768	36.067	**211**
D	8.786	11.922	14.810	**515**	15.151	11.896	19.264	**396**	15.151	11.896	46.692	**163**
E	6.131	9.654	11.436	**666**	10.553	16.006	19.171	**398**	10.553	16.006	43.597	**175**

In Figure 4, the boxes noted in yellow show the fault currents each point on the figure. Note the only the minimum fault values are shown at the end of the line sections, since only the minimum pick up value is relevant.

Selection of Sectionalizing Devices

The transformer damage curve should be obtained from the manufacturer and plotted. Then, the high-side breaker relay settings should be chosen to protect the transformer from damage but be set high enough to carry expected load current along with cold load pickup ability. This curve should be plotted.

To coordinate the high-side protection with the substation transformer damage curve, the high-side time-current curves are referenced to the distribution voltage level for line-to-line and line-to-ground faults. The following factors can be used:

Line-to-line faults: (L-L)

$$\frac{V_{S\,(LL)}}{2 * V_{LG}}$$

Line-to-ground faults:

$$\frac{V_{S\,(LL)}}{V_{LG}}$$

The next step is to determine the substation breaker or recloser relay settings. From the previous steps, the maximum available fault current on the low side is 8,056 Amps. The peak load current will have to be determined and the minimum fault current to the next set of protection devices will have to be calculated.

The relays or electronic reclosers will have to be set to carry the full-load current, any load transfers that might occur during emergencies, and cold load pickup. The lowside protection will also have to coordinate with the highside protection scheme. Reclosers and fuses on the distribution circuits will then have to coordinate with the low-side breaker. The low-side ground protective devices will have to be set to take care of the minimum available fault current. Care must be taken to ensure that the load current of the largest single-phase device is not greater than the minimum ground trip setting.

The engineer will also have to decide whether to utilize a fuse-saving scheme or to minimize the momentary interruptions and sacrifice fuses. Single-phase reclosers can be coordinated as long as the same sequence of either two fast and two slow operations or one fast and three slow operations is selected. To obtain the best coordination between reclosers, the engineer should skip a size, using, for example three 70-Amp, oil circuit reclosers (OCRs) on a three-phase line and then a 35-Amp OCR on a single phase tap. This is not always possible because of the length of line on some distribution circuits. Skipping a size will generally achieve trip coordination, but if it is not possible to skip a size, lockout coordination can often still be obtained.

The maximum and minimum fault currents will need to be calculated at each protection device to ensure that the device will clear the maximum available fault current, carry the expected load current, and interrupt the minimum fault current at the end of the section the device is designed to protect.

On large substations with feeders of three-phase 336 ACSR and larger conductor, it is not uncommon to have a 560-Amp continuous-rated microprocessor-controlled recloser, an 800-Amp continuous-rated microprocessor-controlled recloser, or even a 1,200-Amp continuous-rated breaker with an electronic relay or other microprocessor control on each of the substation feeders.

Since single-phase devices are typically rated no more than 4,000 Amps interrupting ability, they cannot be used near the substation where the fault current exceeds 8,000 amps. They can only be used further down line. Fuses, sectionalizers, will have to be used on all taps in the high-fault current areas.

Additionally, down line three-phase electronic reclosers can be used in the mainline to adequately sectionalize the circuit while observing all of the fault current, load current, and minimum fault current issues discussed in this course.

The TCC curves in Figures 5 and 6 show both the phase coordination for a 560-Amp phase trip recloser at the substation and a 300-Amp phase trip electronic recloser down line. Also shown are the ground trip settings for each device with the station recloser set on 140 Amps and the down line device set on 100 Amps.

Using engineering judgment and minimum fault current calculations, we can set the substation feeder recloser ground trip to a higher value than 140 Amps if the calculations show that the substation device will "see" to the down line recloser for a line-to-ground fault.

The setting of the down line recloser's ground trip to a value less than 100 Amps is generally not recommended since during fault conditions there may be enough imbalance caused by a single-phase-to-ground fault to trip the down line electronic recloser out.

Solution

In this sample problem, the fault currents have been calculated and the load currents have been calculated and both of these values have been put on the circuit diagram (Figure 4) in their respective places.

As can be seen, the station had maximum fault current exceeding 8,000 Amps. The peak load current for the circuit shown is 300 Amps per phase. The zone of protection for the recloser/breaker at the substation is Section #1. The minimum fault current at the end of Section #1 using a 30 ohms fault resistance is 235 Amps line-to-ground minimum. A suggested setting for the feeder recloser/ breaker is, thus, 560 Amps phase trip and 200 Amps (approximately) for the ground trip setting.

Using engineering judgment as a good rule of thumb for the phase trip setting is 150% to 200% of the projected peak loading. Again, using engineering judgment, we could set the ground trip anywhere from 100 Amps to 235 Amps. To provide selective coordination, generally we want to set the ground trip of the feeder recloser/breaker high enough and with the correct TCC so that the down line devices will clear the fault long before the feeder recloser/breaker has to operate. However, for faults in Section #1 in Figure 4, we want the phase - and especially the ground trip - set sensitively enough that the device will operate but not trip out on nuisance problems.

For Recloser #1 in Figure 4, we have a three-phase tap serving a large subdivision at the end of the line. A suggested setting for that device could be 300 Amps on the phase trip and 100 Amps on the ground trip. With a judicious and experienced selection of TCC curves, this Recloser #1 would provide selective coordination with the up line feeder recloser/breaker. Selective coordination is defined, generally, as the condition in which Recloser #1 trips for a fault down line from its location without the feeder recloser tripping out or blinking whatsoever.

For Recloser #2 in Figure 4, which is on the main line, the distribution engineer could choose to eliminate this recloser and let the feeder recloser/breaker "see" to the end of Section #3 depending upon the exposure of the circuit, i.e., right-of-way condition, topography, accessibility, etc. If the distribution engineer chooses to put in Recloser #2, the suggested setting for that phase trip could be 300 Amps and, 100-amp ground trip could be used. Again, with careful selection of TCC curves and trip settings, selective coordination could be achieved between the feeder recloser/breaker and the down line Recloser #3. From the load end of Section #3 to the end of the circuit, standard sectionalizing techniques could be used.

Figure 5 (phase trip) and Figure 6 (ground trip) show the relationship between the substation breaker and the reclosers at Point "B" in Figure 4.

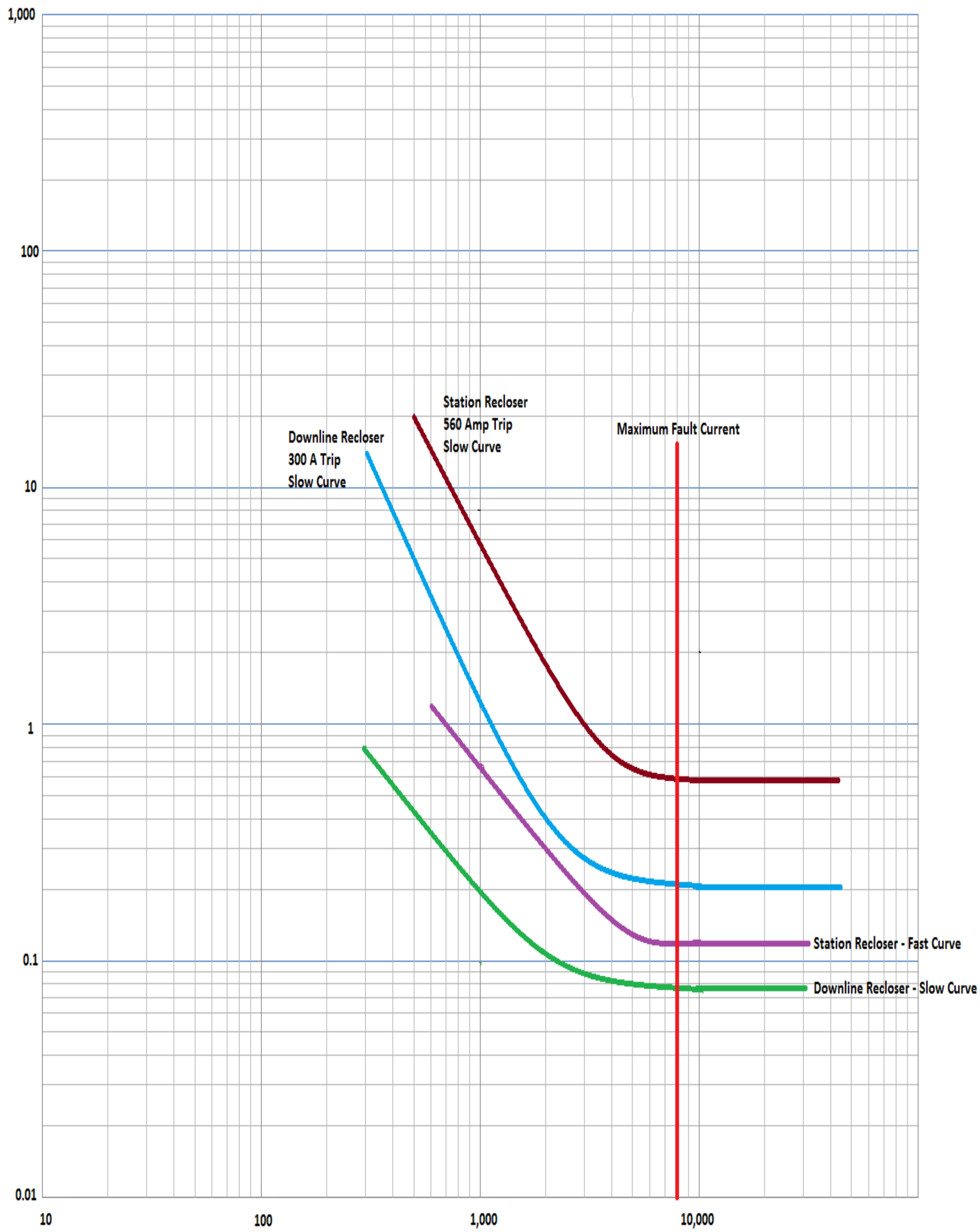

1,000
100
10
1
0.1
0.01
10
100
1,000
10,000
Downline Recloser
300 A Trip
Slow Curve
Station Recloser
560 Amp Trip
Slow Curve
Maximum Fault Current
Station Recloser - Fast Curve
Downline Recloser - Slow Curve

Figure 5

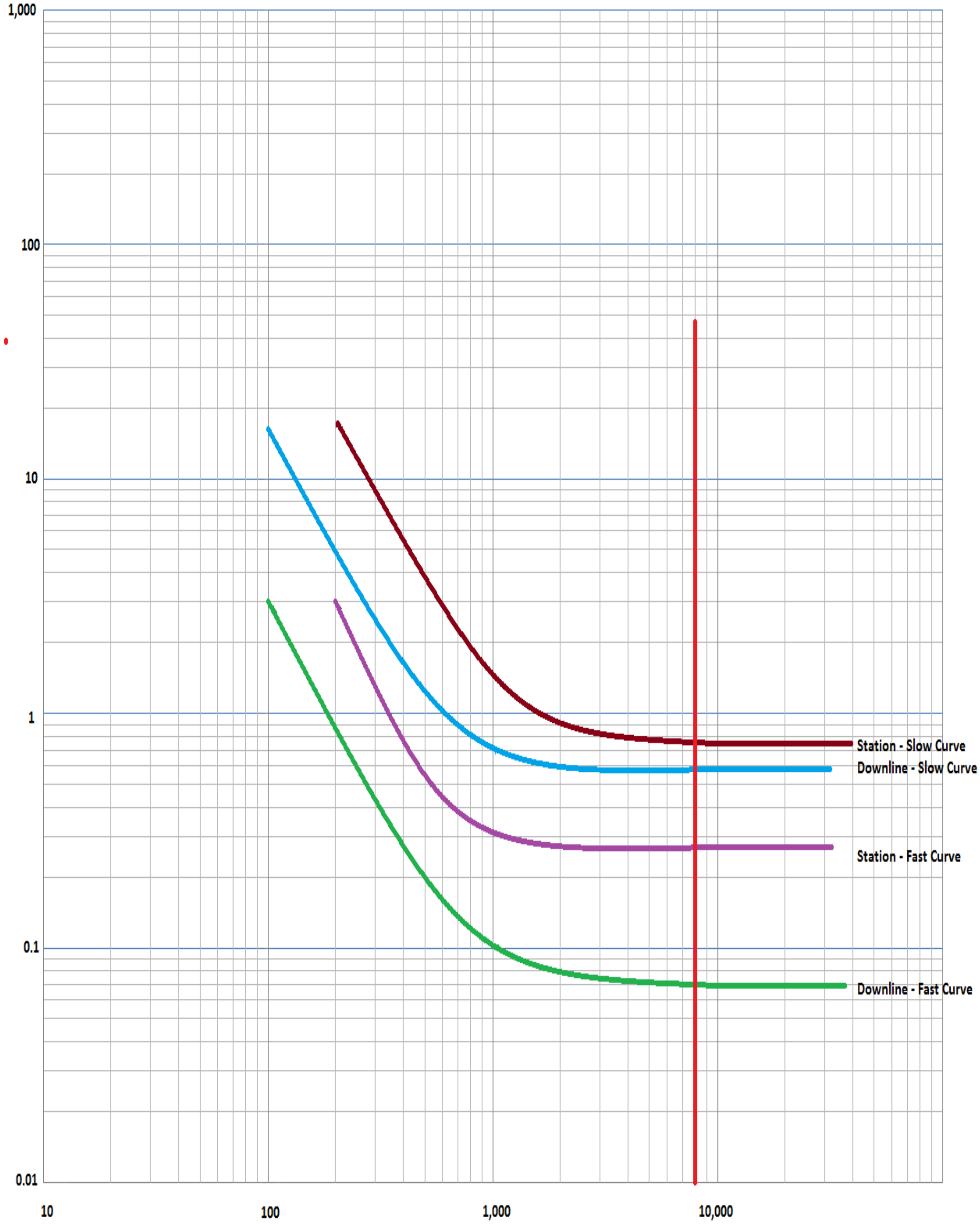

1,000
100
10
1
0.1
0.01
10
100
1,000
10,000
Station - Slow Curve
Downline - Slow Curve
Station - Fast Curve
Downline - Fast Curve

Figure 6

Coordination margins between curves are as discussed earlier in the course and reference material, combined with engineering judgment and field experience. All electronic devices should be equipped with sequence coordination capability to enhance the probability of selective coordination. Additional tricks of the trade to achieve selective coordination are to use similarly shaped but different curves on electronic reclosers in service, change the operations sequence, modifying both the phase and the ground trip curves by using a constant time adder, a curve multiplier, or for the ambitious engineer, simply digitizing a custom curve into the microprocessor recloser/relay. All of these techniques are contained in the references but most require extensive study and experience to implement.

+++