

POWER DISTRIBUTION NETWORKS

Electric power distribution can be defined as the portion of the electric supply system that distributes the power within a local load area. The primary distribution system is typically utility-owned and distributes electric power from a distribution substation to residential, commercial, and small industrial customers of that utility. Secondary, or industrial, distribution systems further distribute the electric power to individual loads. This article is concerned with primary power distribution systems. In a typical situation, electric power is transported from the generators to distribution substations by a transmission network. At the distribution substations, substation transformers step down the voltage to the distribution levels. Distribution lines then transport the power to the individual load sites, where distribution transformers step the voltage down to secondary or utilization levels—which are typically 120/240 V for residential, and 277/480 V for commercial and small industrial customers.

Primary distribution voltages range from approximately 4 kV through 23 kV; with perhaps some 34 kV lines, which essentially function as distribution feeders. (Values stated are line–line rms levels.) During the 1960s, 12 (or 13) kV became the preferred distribution level, and large-scale conversions from 4 kV to 12 kV were undertaken. More recently, 23 kV distribution has been installed in areas with high load density and/or rapid load growth.

The main distribution lines are three-phase. Single-phase laterals are used to feed smaller customers, primarily residential, small commercial, and agricultural. The three-phase lines are of two general types: three-phase three-wire and three-phase four-wire. The three-phase three-wire (or delta) systems have no neutral conductor. The primary windings of the distribution transformers are connected line to line. Three-phase four-wire systems include the three phase conductors plus a neutral, and the distribution-transformer primaries are connected from line to neutral. The four-wire systems are generally multigrounded—grounded at the substation as well as in many locations along a distribution line. Primary and secondary grounds are commonly interconnected at distribution-transformer locations. In the United States, three-phase four-wire distribution is preferred, and the vast majority of 12 kV and 23 kV distribution systems are of this type.

Electric power distribution lines are either overhead or underground. While many variations exist, the typical overhead line is built on wooden poles with the three-phase conductors horizontally laid out on a cross-arm. Underground distribution lines can consist of conductors in conduit or direct burial cables. In particular, underground residential distribution (*URD*) has become popular in residential areas, particularly in new subdivisions. *URD* includes direct buried cables and padmount transformers.

Modern distribution systems are radial in nature. In a radial system, each line is fed by a single source and the power flows radially outward from the supplying substation. The alternative is a networked system, where the network is fed by multiple sources. Primary networks are uncommon, but there are a number of extensive secondary networks in urban areas, as well as spot networks feeding critical loads.

A number of basic textbooks (including but not limited to Refs. 1,2,3) exist that cover both power-system analysis and power distribution in detail.

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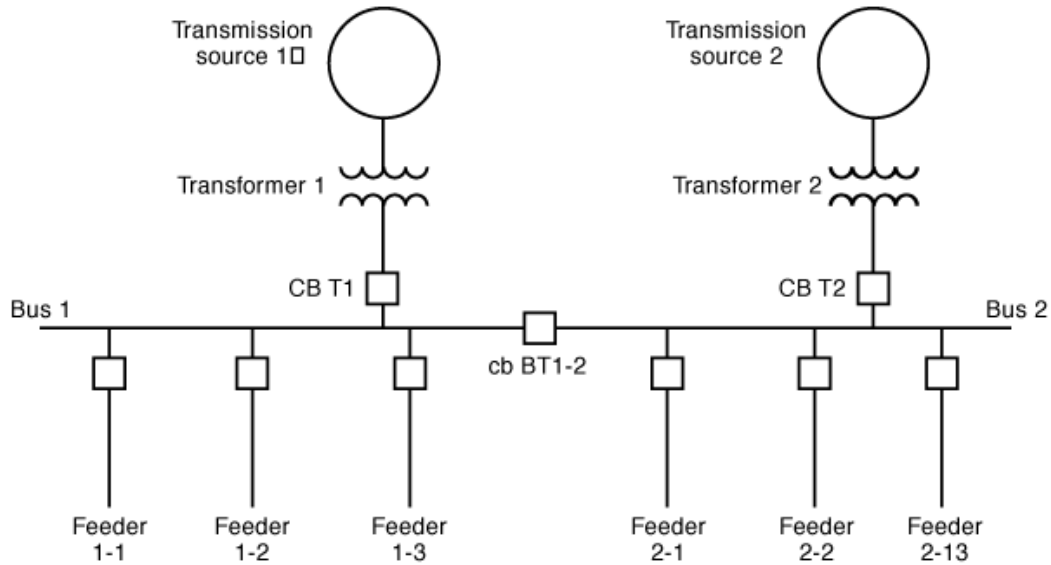


Fig. 1. Representative distribution substation: one-line diagram illustrating switching arrangements.

System Layout and Operation

Figure 1 shows the simplified one-line diagram of a typical distribution substation and the distribution lines fed by that substation. The substation is fed by two transmission lines, which in turn are supplied from independent sources. This substation has two transformers. Each transformer has a secondary circuit breaker and feeds a distribution bus. The two buses are connected by a bus-tie circuit breaker, which often is normally open. Distribution feeders are fed from both buses.

The transformer and bus-tie circuit breakers are automatically switched to provide reliable service to the loads. In the event of the loss of transmission line 1, circuit breaker T1 is opened, followed by the closing of circuit breaker BT1-2. This switching results in a short-term outage to the customers on bus 1, typically in the range of several seconds. When line 1 is returned to service, the feed for bus 1 can be returned to normal without loss of service. Ideally, transformer 2 and associated equipment will be able to support the load of both buses at least temporarily.

There is also a redundancy in the transformers, and a similar switching sequence would be followed for the loss of transformer 1 (which is significantly less likely than the loss of transmission line 1). There is no bus redundancy in this substation, however, so the loss of a bus will result in a longer-term outage to the lines fed by that bus.

Figure 1 shows only one of many variations of distribution substations. Due to load levels, some substations may have four or more transformers. Substations may also have high-side switches to allow feeding both transformers from a single line. The primary goal remains to maintain service to the substation lines following the loss of a transmission line or a transformer.

In some instances, there is insufficient load to justify two transformers. In this situation, reliability is maintained in the manner outlined below for distribution lines.

Figure 2 shows an expanded one-line diagram for a distribution feeder. The many distribution transformers feeding loads along this feeder are not shown on the diagram. The feeder is tapped from a substation bus through a circuit breaker. The feeder is divided into segments by reclosers and sectionalizing switches.

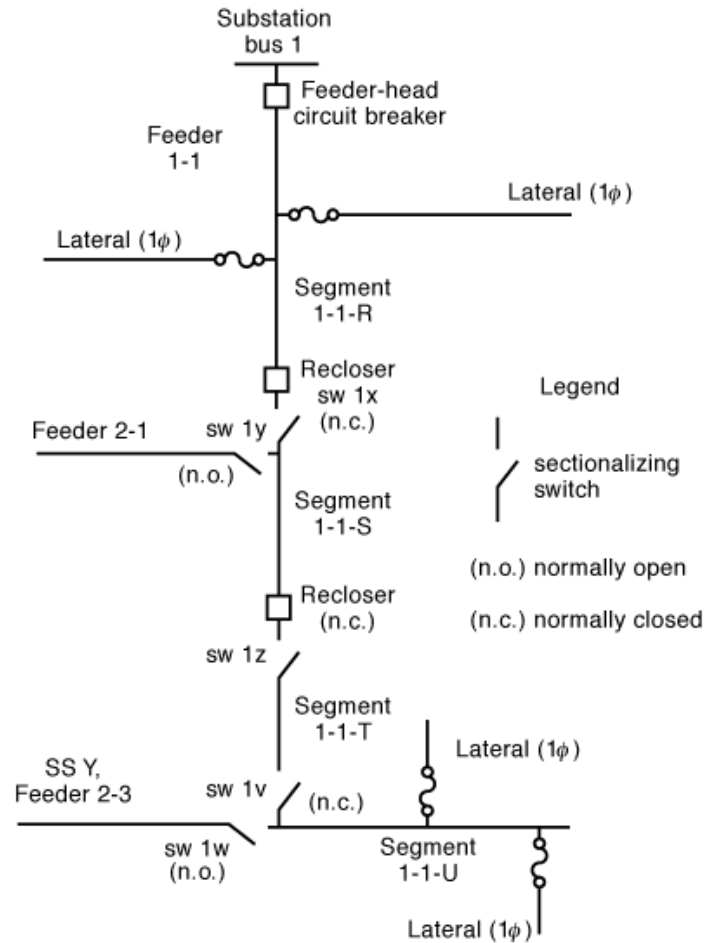


Fig. 2. One-line diagram of a distribution feeder, showing feeder head circuit breaker, line reclosers, sectionalizing switches, and single-phase fused laterals.

Reclosers are self-contained devices that sense, interrupt, and reclose on line faults. Sectionalizing switches will switch load current but will not interrupt fault current. Most are manually operated, and are placed to allow the switching of feeder segments. Consider, for example, a permanent line fault that occurs on feeder segment 1-1-R. The feeder-head circuit breaker will respond by clearing the fault and locking out, and the entire feeder will be out of service. The initial response to this would be to open sectionalizing switch 1x and close sectionalizing switch 1y, restoring service to the entire line 1 except the faulted line section 1-1-R. This restoration is accomplished with the feeder 2-1 as a source. In many cases, the sectionalizing switches are operated manually, and the downstream loads will experience an outage of 30 min or more. One goal of distribution automation is to automatically detect fault location and operate sectionalizing switches to reduce the outage time for unfaulted sections, perhaps to the range of 10 s to 30 s. Customers directly fed from the faulted section, of course, will need to wait for line section repairs for service restoration.

Service continuity is much more important for some loads than for others. Additional methods are available to improve reliability, and are discussed in later sections. Also, it should be noted that overhead distribution

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lines can be subject to widespread problems due to events such as windstorms and ice storms. In these cases, service restoration will be somewhat slower.

At the primary distribution level, substantial diversity of the load is experienced, as all loads are never on line simultaneously. The system is built to meet peak power demand rather than total connected demand. The peak power demand at some point on the system is defined as the largest average kilowatt demand experienced over a defined time period, typically 15 min, 30 min, or 1 h. Distribution systems are subject to daily, weekly, and seasonal fluctuations in load levels. The load factor is defined as the ratio of average load to peak load over a period of time. The daily load factor, for example, is defined as

$$\text{DLF} = \frac{[\text{total energy (kWh)}]/24 \text{ h}}{\text{peak power demand (kW)}} \times 100\% \quad (1)$$

Good load factors indicate a fuller utilization of the system capacity and, as in any industry, are desirable in that they lead to lower costs due to the spreading of the fixed capacity costs over a larger energy consumption base. In the case of many large customers, customer billing is based on a combination of energy charges and demand charges in order to more closely approximate the true costs of service.

Steady-State Operation

Acceptable voltage range. The power distribution system is required to deliver electrical energy to the load with acceptable steady-state and dynamic characteristics. The steady-state requirements include the frequency, magnitude, and waveshape of the supplied voltage. The steady-state frequency variation on distribution systems fed from the interconnected power system is small, typically a fraction of a hertz. Frequency variation on these systems is not a concern. Frequency variation can be a concern on small standalone power systems, however, particularly systems with large-load motors.

Voltage magnitude is a major concern of distribution designers. Preferred nominal voltage ratings are set by standards such as ANSI C84.1-1989 or IEC 60038. Standards also describe the permissible operating ranges around the nominal voltage. These standards represent an agreement providing a consistent design criterion for the utility, facility, and equipment designers. The IEEE Red Book (IEEE Std. 141-1993) (1) provides a good description of the rationale and implementation of ANSI C84.1.

The most familiar system voltage in ANSI C84.1-1989 is 120 V. The maximum and minimum system voltages are 126 V and 113 V, respectively, which allow a $\pm 5\%$ tolerance around nominal. A corresponding nominal utilization voltage (at the load) is 115 V, with maximum level of 126 V and minimum of 110 V. The distinction between system voltage and utilization voltage is made to allow for the voltage drop through the distribution transformer and within a facility. Typically, the allowable voltage range is apportioned to the primary line drop, distribution transformer drop, and secondary line drop.

Power flow in three-phase systems. In many cases, the distribution system and its loads can be considered to be operating under balanced three-phase conditions. In this situation, both source and load can be considered to be wye-connected for the analysis of the system voltage, current, and power flows. Figure 3 shows a balanced wye-connected source feeding a balanced wye-connected load. The neutral points of the source and load are connected, forming a four-wire system. The complex power flowing in A phase is

$$\mathbf{S}_A = \mathbf{V}_{an} \mathbf{I}_a^* \quad (2)$$

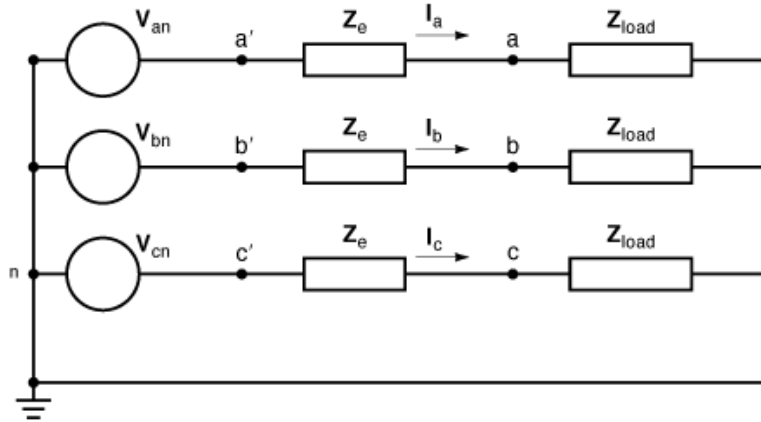


Fig. 3. Balanced three-phase wye-connected source feeding a balanced wye load.

The bold type designates a complex or phasor quantity, and the asterisk denotes the complex conjugate. As the system is balanced, the same complex power will flow in both B and C phases, so the total three phase complex power is

$$\mathbf{S} = S\angle\phi = P + jQ = 3\mathbf{V}_{an}\mathbf{I}_a^* \quad (3)$$

where ϕ is the angle by which current lags voltage (the power-factor angle). The real power (in watts) and the reactive or imaginary power (in vars) are then

$$\begin{aligned} P &= 3V_{an}I_a \cos \phi \\ Q &= 3V_{an}I_a \sin \phi \end{aligned} \quad (4)$$

Note that all quantities in Eq. (4) are scalar quantities—voltage and current magnitudes and real and reactive powers. Q is positive when current lags voltage—signifying that vars flow towards inductive loads, which are typical on power systems.

The volt-ampere magnitude is then

$$S = \sqrt{P^2 + Q^2} \quad (5)$$

and the power factor, pf, is defined as

$$\text{pf} = \frac{P}{S} = \cos \phi \quad (6)$$

Figure 4 shows the power triangle and associated voltage and current flow for a typical inductive load.

The A-phase analysis of Fig. 3 is therefore sufficient to solve for voltage, current, and power. For analysis purposes, a per-phase equivalent circuit is employed. The per-phase equivalent circuit for Fig. 3 is shown in Fig. 5. With load voltage and current known, the source voltage can be found by circuit analysis. Note that the equivalent-circuit parameters are the line-neutral voltage and line currents. In most cases

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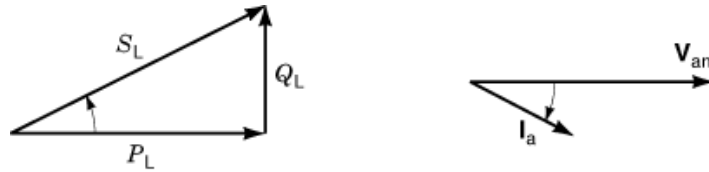


Fig. 4. Power triangle and the corresponding A-phase phasor diagram for the load in Fig. 3.

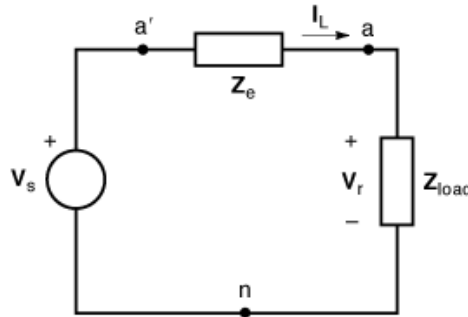


Fig. 5. Per-phase equivalent circuit of the balanced three-phase system of Fig. 3.

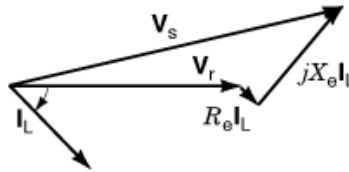


Fig. 6. Phasor diagram for Fig. 5, with equivalent impedance $\mathbf{Z}_e = R_e + jX_e$.

involving three-phase systems, voltages are stated as line–line quantities ($V_{L-L} = \sqrt{3} V_{L-n}$) and flows (S) are stated in terms of three-phase volt-amperes.

The load voltage will typically decrease as load levels increase. The percentage voltage regulation is defined as

$$\text{VR} = \frac{V_{\text{no-load}} - V_{\text{load}}}{V_{\text{load}}} \times 100\% \quad (7)$$

As discussed in the preceding subsection, allowable regulation is approximately $\pm 5\%$. The phasor equation for Fig. 5 is

$$\mathbf{V}_s = \mathbf{V}_r + \mathbf{Z}_e \mathbf{I}_L \quad (8)$$

The impedance \mathbf{Z}_e is the equivalent series impedance as seen by the load, while the source voltage \mathbf{V}_s is the open-circuit (no-load) voltage at the load terminals. Figure 6 shows the phasor diagram for Fig. 5 with a lagging current flow as is typical of power-system loads. Equation (7) states that the voltage magnitude, not angle, is the more important consideration for distribution systems.

Analysis of circuits with transformers. Transformers are used throughout the power system to adjust the voltage to the levels needed for economical transmission or distribution. In the balanced per-phase analysis of distribution systems, an $n : 1$ ratio transformer will complicate the diagram of Fig. 5. Figure 7 shows the one-line diagram and the per-phase diagram of a distribution system with a single stepdown transformer. Direct solution of Fig. 7(b) is somewhat difficult, and becomes increasingly difficult as the number of transformers in a system increases. Two alternative methods are used to solve this circuit:

- (1) The first method is based on the reflection of voltage across the transformer by the turns ratio, and of impedances across transformer windings by the turns ratio squared, followed by the solution of the circuit in terms of volts and amperes. This is equivalent to finding the Thevenin equivalent of the source circuit. The resulting equivalent circuit is shown in Fig. 7(c).
- (2) The second method involves the use of per-unit quantities rather than volts, amperes, and ohms. A brief description of the per-unit system is contained in the following subsection. In-depth descriptions can be found in basic power-system texts, such as Ref. 2 or 3. The per-unit system is widely used in power-system analysis and effectively removes the transformer turns ratio from calculations through normalization. It is also convenient in that it allows a convenient method for expressing voltage levels and other quantities. For example, a voltage of 0.96 per unit is immediately recognizable as being at 96% of its nominal value. Most if not all power flow software employs per-unit calculations. The resulting per-unit equivalent circuit is shown in Fig. 7(d).

Per-Unit System. As indicated in the previous section, power-system analysis is often conducted with the use of per-unit quantities. Through this method, the turns ratios of most transformers can be normalized to unity, with a resulting simplification of the computations. Additionally, voltages and currents are more readily interpreted in per-unit terms, as are transformer, generator, and motor impedances when referred to their own base.

The first step in normalizing system quantities to a common system base is the choice of the three-phase volt-ampere base. Common choices are 1 MVA and 100 MVA. The second step is to choose voltage bases for each section of the system—a section being defined as a group of components at the same voltage level. Typically, the nominal line–line rms voltage rating of a section would be chosen as the voltage base for that section. In adjacent sections of the system, the voltage base should be chosen according to the turns ratio of the transformer(s) connecting the two adjacent systems. This results in an apparent turns ratio of 1.00 between sections, and allows the simplification of Fig. 7(d) when solving the system. In cases where this choice is not possible, corrections can be applied (3).

Following these choices on a given section, we have

$$\begin{aligned}
 I_{\text{base}} &= \frac{S_{\text{base3}}}{\sqrt{3}V_{\text{baseL-L}}} \\
 Z_{\text{base}} &= \frac{V_{\text{baseL-L}}}{\sqrt{3}I_{\text{base}}} = \frac{V_{\text{baseL-L}}^2}{S_{\text{base3}}}
 \end{aligned}
 \tag{9}$$

The subscripts are chosen to emphasize that three-phase volt-amperages and line–line voltages are the quantities used in these particular equations. With these base quantities, the per-unit version of Eq. (8) is

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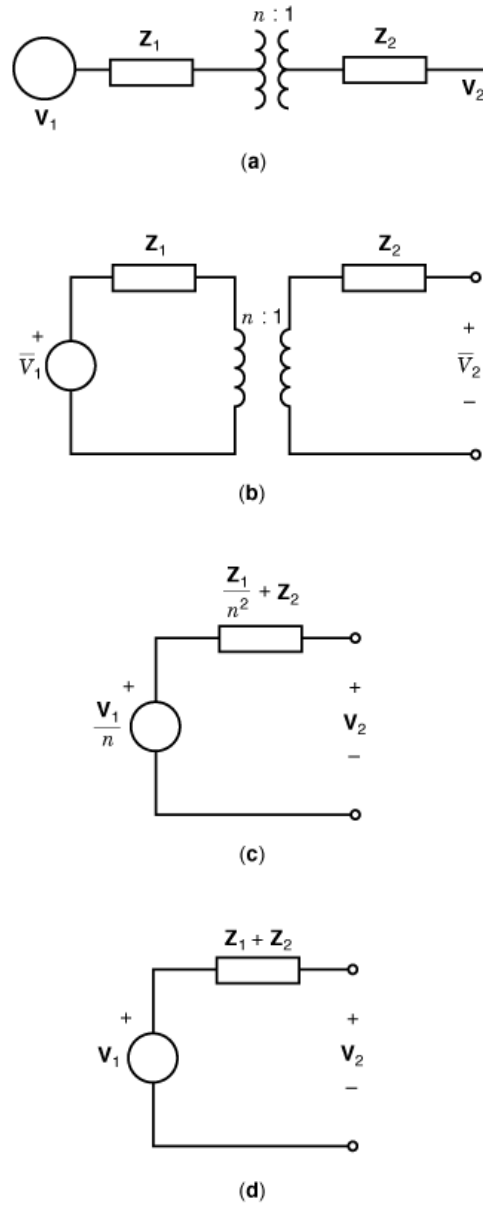


Fig. 7. (a) One-line diagram. (b) Per-phase equivalent circuit. (c) Per-phase circuit with quantities referred to the transformer secondary. All quantities in secondary are in volts or amperes. (d) Per-phase, per-unit diagram. All quantities are per unit.

found by normalizing both sides of the equation:

$$\frac{\mathbf{V}_s}{V_{\text{base}}} = \frac{\mathbf{Z}_e}{Z_{\text{base}}} \frac{\mathbf{I}_L}{I_{\text{base}}} + \frac{\mathbf{V}_r}{V_{\text{base}}} \quad (10)$$

Note that \mathbf{V}_s and \mathbf{V}_r are line-to-neutral quantities, so the appropriate base is the nominal line-neutral voltage. As a result,

$$V_{\text{base}} = \frac{V_{\text{baseL-L}}}{\sqrt{3}} \quad (11)$$

Combination of Eqs. (9) and (11) yields

$$V_{\text{base}} = Z_{\text{base}} I_{\text{base}} \quad (12)$$

Therefore the equality of Eq. (10) is maintained. Each ratio in Eq. (10) is then expressed per unit of its base:

$$V_{\text{su}} = Z_{\text{eu}} I_{\text{Lu}} + V_{\text{ru}} \quad (13)$$

The subscript u is included in this equation to emphasize that these are per-unit values. Equation (13) and Eq. (8) have the same form, the only difference being that Eq. (8) is expressed in volts, amperes, and ohms, while all values are per unit in Eq. (13).

The impedances of generators and transformers are generally specified as per-unit values with base quantities chosen to be the machine's rated values. These quantities must be converted to the system per-unit bases in order to be consistent with the rest of the system. This conversion from an old base to a new base can be found to be

$$Z_{\text{unew}} = Z_{\text{uold}} \left(\frac{S_{\text{base new}}}{S_{\text{base old}}} \right) \left(\frac{V_{\text{baseL-L old}}}{V_{\text{baseL-L new}}} \right)^2 \quad (14)$$

As a result of the care used in picking base quantities, an impedance being viewed on either side of a transformer will have the same value per unit (as opposed to being reflected by the turns ratio squared when expressed in ohms). Therefore, a two-winding transformer will have two sets of bases for voltage, current, and impedance. These bases are consistent, however, so that the per-unit voltages and currents will be the same on both sides of the transformer, apart from differences caused by coil resistance, leakage inductance, and magnetizing effects.

Analysis of circuits with multiple loads. Practical distribution systems, of course, have many customers and many more loads. A representative one-line diagram for a pair of primary distribution lines with multiple loads is shown in Fig. 8. It is required that voltage be supplied to each of these load buses within the required voltage limits, over all operating conditions.

With these multiple loads each operating at a different voltage, the solution becomes complicated, and a hand calculation is not practical. Voltages and line flows in these cases are typically solved on the computer with a load flow program (3). Input data for radial distribution systems include line impedances, transformer and capacitor bank data, load levels, and source voltage. Both commercial and educational load flow programs are readily available for this analysis.

The substation bus voltage will be regulated by load tap changers (*LTCs*) on the substation transformers. Transformer tap changers allow a change of transformer turns ratio, which in turn changes the secondary voltage for a given primary voltage. As implied by the name, load tap changers do this under load, and are generally controlled by a voltage-sensing relay to maintain a fixed voltage at the bus or some downstream

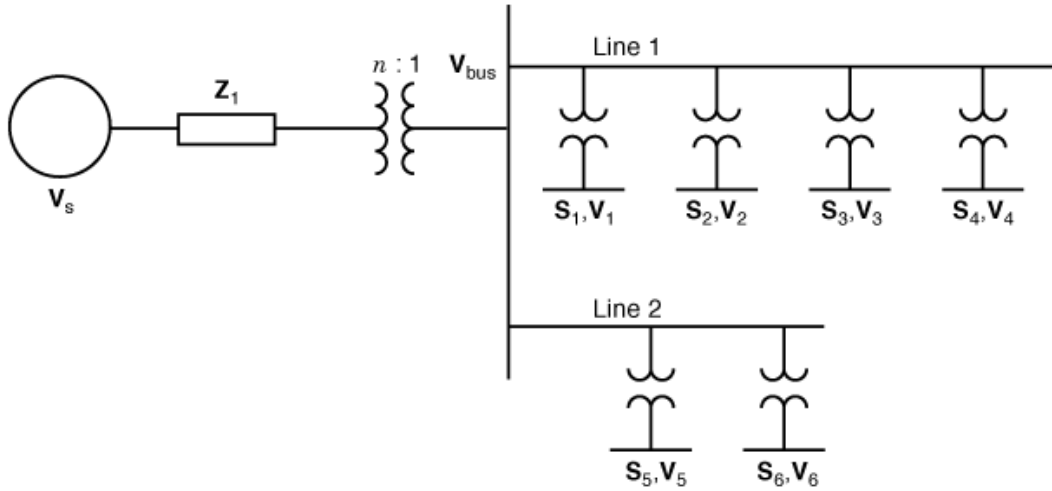


Fig. 8. One-line diagram of a simple two-line radial distribution system.

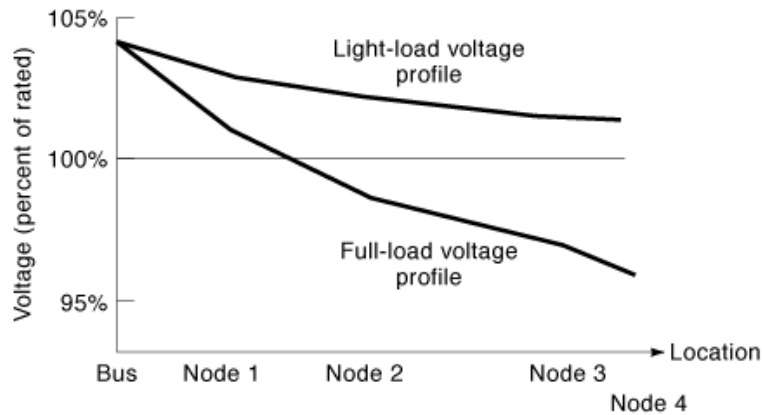


Fig. 9. Full-load and light-load primary voltage profiles for distribution line 1 of Fig. 8.

location. Under light load conditions, there will be little regulation along the line, and the downstream loads will be served at near-bus levels.

Loading increases, however, will cause increased voltage drop along the line. At full-load conditions, the primary voltage at line end will sag appreciably from light load, and the utilization voltage at line end can go out of range. As seen in Fig. 9, voltage at a customer location is influenced by the load drawn by all customers along the feeder.

For a given system, the distribution system designer has several options to avoid this:

- (1) Distribution-transformer no-load taps
- (2) Voltage regulators
- (3) Power-factor correction capacitors

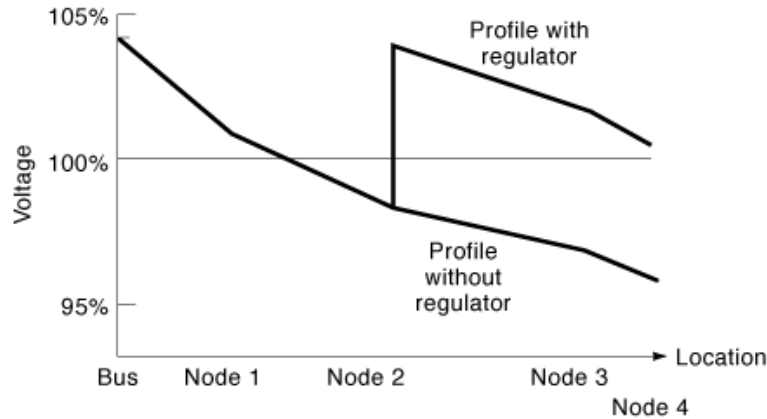


Fig. 10. Full-load voltage profiles for feeder 1 with a voltage regulator placed ahead of node 2.

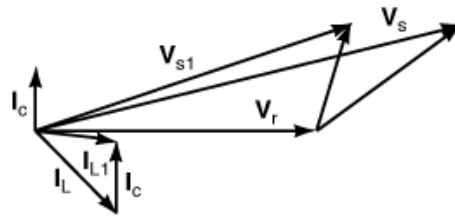


Fig. 11. Phasor diagram showing the effect of the capacitor current I_c on the line current and source voltage required to support a load voltage of V_r . I_L : line current without capacitor; I_{L1} : line current with capacitor; V_s : required source voltage without capacitor; V_{s1} : required source voltage with capacitor.

No-load taps on the distribution transformer change the ratio of primary to secondary distribution voltages in a fixed manner. No-load taps are generally available on distribution transformers, but can only be changed with the transformer deenergized. A change of no-load tap will increase both the full-load and the light-load voltage in the same proportion. When increasing the full-load voltage with a transformer tap change, care must be taken not to incur an overvoltage under light load conditions.

Voltage regulators placed in the line will provide a fixed voltage at the regulator output. Several technologies are available for this purpose. The effect of these devices is similar to that of load tap changers at the substation bus. The distribution system will typically operate with an allowable primary drop along the line. When this allowable drop is reached, a voltage regulator is called for, which provides a fixed voltage at that point. The diagram of Fig. 10 illustrates full-load regulation along a line, with a voltage regulator placed ahead of node 2.

Power-factor correction capacitors are the third option available for influencing voltage regulation on the distribution system. They allow a low-cost, convenient solution to voltage problems, and are widely used. Figure 11 revisits the phasor diagram of Fig. 6 to illustrate the effect of the capacitor on voltage levels. The effect is twofold—with the capacitor supplying the load vars, the line current level is reduced, which reduces the product of impedance and current (this also reduces equipment loss and heating, which is another benefit). Furthermore, the corrected current is more nearly in phase with the voltage. The product of current and inductive reactance therefore is nearly 90° out of phase with the load voltage. While this causes a large angle difference between source and load voltage, the magnitude of source voltage relative to load voltage is reduced.

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For a relatively low additional cost, control can be added to the distribution capacitor bank. The control allows the removal of the capacitor bank under light load conditions, to prevent overvoltages from occurring. Two types of controller are in common use—time-of-day control and voltage-level control. These terms are both self-explanatory—time-of-day control is preprogrammed to add and remove the capacitor at times when load is expected to be increasing and decreasing; voltage-level control monitors the line voltage and adds or removes the bank as indicated. Each method has its advantages, and both are employed.

Distribution Equipment

Transformers. Transformers are used to step voltage down from different levels of the electric system. Distribution transformers are defined as those transformers that step voltage down from utility distribution levels (2.4 kV through 34.5 kV) to customer utilization levels (120 V through 15 kV). Utility-owned distribution transformers are liquid-filled and may have multiple windings. There are two common types of distribution transformers: padmount and pole-mounted.

Padmount transformers are often provided to serve industrial and commercial customers. They are installed on a concrete pad, typically on the customer's property. These transformers are provided with taps for voltage selection; automatic load tap changers are optional.

Pole-mounted transformers are used for small commercial and residential customers. They are mounted on poles and fed from aerial distribution lines. Some pole-mounted transformers are provided with taps, usually when distribution service voltages on the utility line are expected to change.

Circuit breakers. A circuit breaker is a device used to interrupt a circuit. Circuit breakers consist of sets of separable contacts that open a circuit upon initiation, and are capable of interrupting fault currents. Modern circuit breakers operate within 5 cycles. Initiation is provided through both manual and automatic means (protective relaying). There are numerous types and styles of relays that allow automatic initiation of circuit-breaker tripping to be customized based on the installation. This flexibility makes circuit breakers, with associated relaying, the primary control and protective device in an electric distribution system.

Several different styles of circuit breaker exist. Circuit breakers in switchyards can use oil-filled or gas-filled (SF_6) interrupting chambers to extinguish the arc. Vacuum chambers are also used for interruption in some breakers, and others interrupt the arc in air. The current trend in the industry has been to move away from open-air switchyards for distribution substations. Recent improvements in the reliability of metal-clad switchgear and the introduction of gas-insulated substation (*GIS*) equipment for voltages above 15 kV have obviated the need for large outdoor yards. Both styles of breaker use vacuum or gas-filled chambers to extinguish the arc during circuit interruption. Due to their function and location in the distribution system, these devices are rated to handle the maximum available fault current.

Reclosers. Most faults on above-ground feeders are of short duration, being due to trees and lightning. An automatic circuit recloser is a self-contained device that automatically interrupts and recloses an ac circuit. The reclosure takes place after a suitable delay to allow the fault to clear itself. The number of attempts at reclosing is adjustable. In the event the fault remains on the line at the end of the reclosing sequence, the recloser will remain open to isolate the fault. Interruption takes place through the use of separable contacts operating within an oil-filled interrupting chamber (4).

Automatic Sectionalizers. Sectionalizers are used in conjunction with reclosers. A sectionalizer consists of a set of contacts immersed in oil and a fault counter to initiate opening of a circuit. The sectionalizer is located on the load side of the recloser. The operation is as follows. If the current is high enough to indicate a fault, the fault counter increments by one as the upstream recloser opens. If the count reaches a preset number during a fault sequence, the sectionalizer opens the line and removes the faulted portion from the system. As the opening of the circuit takes place when the recloser is in the open position, an automatic sectionalizer does not have to interrupt fault current. Because of this, it is a relatively low-cost device.

Distribution Fuse Cutouts and Power Fuses. Distribution cutouts are typically used to sectionalize distribution feeders and circuits. They consist of a fuse support, holder, and link, and are designed to be mounted on poles or crossarms. The most common form of fuse link is the expulsion-type fuse. These fuses work through the melting of the inner fuse link due to the heat of the arc. A gas is generated within the fuse tube that deionizes the arc path. Adequate clearances are necessary between expulsion fuses and other equipment, as the ionized particles are forced out of the tube and can cause flashover to nearby circuits.

Power fuses are installed in substations and are termed *E-rated fuses* according to National Electric Manufacturer's Association (*NEMA*) standards. The most common types of power fuse are the expulsion type and the current-limiting type. Current-limiting fuses are designed to limit the flow of heavy fault currents. This is accomplished by the rapid melting of a number of series fuse elements. Significant arc voltages develop across these elements and inhibit the buildup of fault current. These fuses can result in a substantial reduction of the instantaneous peak fault current.

Line and cable. Distribution feeders can be run overhead on poles or underground. Overhead lines are typically run on wooden poles along roadways. Aerial lines are commonly aluminum or aluminum cable, steel-reinforced (*ACSR*) (5). Lines are mounted on poles through the use of insulators. Insulators used to be porcelain, but modern installations often use a polyethylene polymer.

Underground systems are either duct-type or direct bury. An underground system offers many advantages over overhead systems. The major advantages include the esthetic value of removing poles and lines from residential areas and freeing the circuit from the effects of lightning, wind, and precipitation. The disadvantage of duct systems is the significantly higher installation cost. Underground cables are typically shielded with XLP or EPR insulation, although there are some areas where paper-insulated, lead-sheathed (*PILC*) cable is still used. A common form of underground system is underground residential distribution (*URD*). These systems typically consist of direct-buried cable, which do not require ductbanks or manholes. Recent designs have upgraded the security of the *URD* system by installing the cable in conduit buried in sand. This change has been initiated due to instances of premature cable breakdown and accidental circuit interruption by contractors digging near *URD* feeders.

Surge Arresters. Surge arresters are used to protect equipment from lightning strikes and other line surges, as discussed below in the section "Overvoltage Protection." Distribution arresters have three different classes. From lowest level of protection to highest, they are *distribution class*, *intermediate class*, and *station class*. Each succeeding class provides a higher energy dissipation capability. All styles of arrester are given duty-cycle ratings based on factory testing. Gapless arresters are also rated according to their maximum continuous operating voltage (*MCOV*). For ungrounded and high-resistance grounded systems, the arrester must withstand continuous line-to-line voltage. For directly grounded systems, the arrester continuous rating can approach the line-ground operating voltage.

Distribution-System Reliability and Availability

Reliability, in its most general form, is the overall ability of a system to perform its function. The function of an electrical system is to supply electrical energy as economically as possible with an acceptable degree of service continuity. During the design and planning of an electric system, these economic and reliability demands often conflict. In order to make an educated decision about which option provides the best solution, an engineer needs as much information as possible. The world's growing dependence on electric energy has made the design of reliable electrical systems increasingly important.

Until recently, design criteria and techniques developed through experience have been the only practical methods available to resolve conflicts between economy and reliability (6). Traditional deterministic reliability assessment is the method most engineers apply to determine whether or not a system will operate reliably. This method applies potentially severe (contingent) system operating conditions, under which short-circuit,

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load-flow, coordination, and stability studies are performed. An inherent disadvantage with this approach is that it is sometimes difficult to define a reasonable contingent operating condition based on anything more than engineering experience. In terms of reliability assessment, the comparison of two systems, reliable in a deterministic sense, may not easily identify the more reliable of the two. Modern electric distribution systems are complex and highly integrated. As analyses of economy and reliability tradeoffs have become more complicated, the application of probability-based techniques to quantify system reliability has become more common.

To allow for the probabilistic nature of system operation and customer reliability demands, probability concepts can be applied to the system topography. While the deterministic approach identifies which contingencies will result in undersirable system operation, the probabilistic approach determines the risk that undesirable system operation will occur, based on a criterion of desirable system operation. The results can help find unreliable components or aid in system planning and design. Probabilistic analysis also allows objective comparisons of systems or proposed modifications. When cost-per-outage data are available, an economic analysis can be completed to calculate payback periods for electric-system improvements. This allows decisions to be based on total owning cost over the life of the equipment, rather than merely installation cost.

Results of probabilistic reliability assessment are expressed as reliability indices that represent the system adequacy. The primary indices for distribution systems are failure rate (or frequency of failure), average failure duration, mean time between failures (*MTBF*), forced downtime, and system availability:

Failure Rate (f_f or λ). The frequency of failure, that is, the rate at which the system transitions from an operational state to a failed state. It is often expressed as the number of failures per year.

Average Failure Duration (r). The average number of hours of downtime per failure.

MTBF (Y_f). The reciprocal of the failure rate, equal to the average number of years between failures.

Forced Downtime (λ_r). The expected number of hours per year that the system will be out of service.

System Availability (A): The probability that the system is available (i.e., not out of service). Its complement, unavailability (the probability that the system is out of service), is also used extensively.

Analytical methods for evaluating distribution systems have seen rapid development in recent years, as reliability engineers have begun to concentrate on modeling distribution systems. Simulation, or Monte Carlo, analysis techniques have been developed recently. While analytical techniques develop and solve the system model using mathematical formulas, Monte Carlo simulation methods simulate the actual behavior of the system. In a sense, the simulation method examines the system as a series of real experiments. The development of computer systems over the past several decades has allowed the advancement of simulation techniques. The advantage of the simulation method is that, in instances where system effect or system processes need to be approximated to solve using the analytical method, the Monte Carlo method can solve using the true system behavior.

Methodology for reliability assessment is a complex topic, beyond the scope of this work. Apart from *Reliability Evaluation of Power Systems* (6), there are several good reference books on the subject including the "IEEE Gold Book" (7) and *Applied Reliability Assessment in Electrical Power Systems* (8).

Overvoltage Protection

The primary causes of short-term distribution-system overvoltages are lightning and circuit switching. On primary distribution systems, lightning-induced voltages are the major concern. On some industrial systems, switching overvoltages are of concern, particularly in situations with circuit breakers that exhibit current chopping (9).

Lightning strokes can affect distribution systems through direct strikes or through induction associated with strikes near the line. Lightning events are extremely fast, and the high rate of change of voltage can also cause problems in transformers, motors, and generators.

Distribution equipment is designed with a basic insulation level (*BIL*). The system designer coordinates the BILs of the system components, and provides overvoltage protection, primarily through the use of surge protective devices. With properly applied surge arresters and a suitable grounding system, the system will withstand the large majority of lightning events without equipment failure.

Surge Propagation. Both direct and indirect lightning strokes will induce traveling waves on the distribution line. These waves will propagate away from the point of the stroke at speeds approaching the speed of light. Reflections will occur at line discontinuities—in the worst case, at an open circuit, where the wave will be fully reflected. The incident and reflected waves in this situation will result in the doubling of the voltage at the open circuit.

Transmission lines are characterized by their surge impedance and their propagation velocity (10). Where lines of different impedance meet (or a line terminates into an open circuit, short circuit, transformer coil, etc.), discontinuities in the wave propagation occur. Solution of the wave equations (see, e.g., Ref. 4 or 5) shows that a portion of the incident wave will be reflected, while another portion will be transmitted. The reflection coefficient, ρ_R , for a wave traveling on a line with characteristic impedance Z_{c1} meeting a discontinuity with impedance Z_{c2} is known to be

$$\rho_R = \frac{Z_{c2} - Z_{c1}}{Z_{c2} + Z_{c1}} \quad (15)$$

The incident and reflected waves will add as the reflected wave travels back down the line. A reflection coefficient of +1 will result in a doubling of the voltage. With a reflection coefficient of -1 (as occurs with a short circuit), however, the reflected voltage will subtract from the incident, and the voltage will go to zero along the line as the reflected wave propagates back down the line.

Due to the potential for reflections to add to incident waves, it is important to place surge protective devices at line discontinuities and at other locations where they will protect the distribution equipment. Transformer primary windings, distribution capacitors, and line reclosers will generally have surge protection, as will cable risers (the transition points between overhead and underground line segments). In many cases, placement of arresters in these locations will provide sufficient overvoltage protection. In low-load-density areas, however, additional devices are needed on overhead lines with no static wire.

In protecting equipment, it is important to place the surge arrester as near as possible to the protected equipment to minimize the effect of travel time and reflections. Figure 12 shows a typical situation with a surge arrester mounted on the distribution-system tank adjacent to the transformer bushing.

Figure 13 illustrates the exposure that can result from short displacements with a steep wavefront traveling at nearly the speed of light—approximately 0.3 m/ns. The wave reaches the junction and is transmitted toward both the surge protector and the transformer coil. Two nanoseconds later, the surge reaches the protector, which clamps the voltage at its protective level. Another 2 ns go by while the clamped wave propagates up the lead to the junction. Meanwhile, the unclamped wave has reached the transformer winding at its full level, and is reflected. The incident plus reflected waves will be present at this point until the clamped wave propagates from the junction to the coil, 4 ns later. If the wave rises above coil capability within this time, the insulation can be overstressed. The lead length between junction and coil also creates a problem. Consider a surge propagating past the protector to the coil. On reaching the coil, it will be reflected back toward the protector, with the reflected wave adding to the incident wave as it propagates backward. On reaching the protector (neglecting the protector lead length), the protector will clamp the voltage at an acceptable level. This clamped wave will be reflected back toward the coil, with another transit delay involved. Therefore, if the

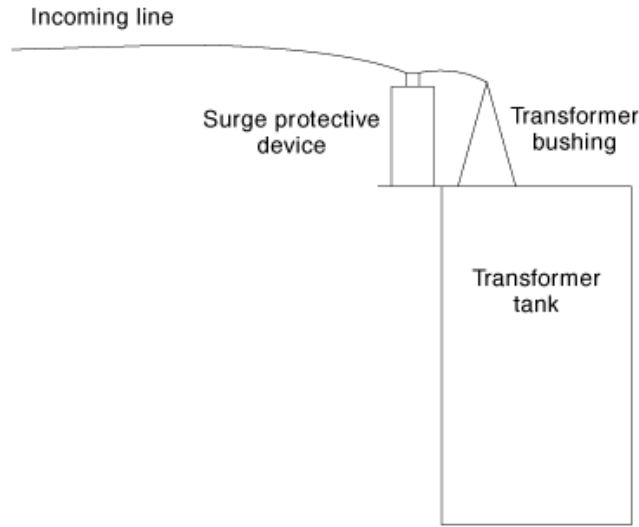


Fig. 12. A typical installation of an overhead distribution transformer with a surge protector mounted on the tank.

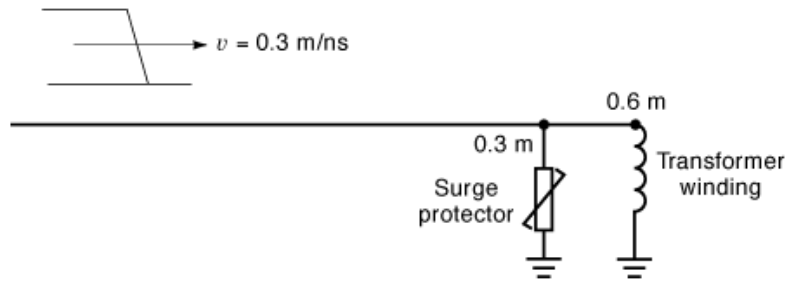


Fig. 13. Transformer–surge-protector installation with 4 ns delay due to protector lead length and 6 ns delay due to coil lead length.

reflection is positive, the coil can be subjected to an unclamped voltage for twice the transit time of the coil lead.

Two types of surge protective devices are in use today—gapped arresters and gapless arresters. While gapless arresters are the newer technology and are preferred for new installations, many gapped devices remain in service.

Gapless arresters are made with metal oxide varistor (MOV) technology. The I - V characteristic of these arresters can be approximated as

$$i = K v^\alpha \tag{16}$$

where i is the arrester current and v is the voltage across the arrester. The MOV can exhibit α values in the range of 30 to 40, which provides a device with effective voltage clamping action accompanied by low current draw in normal situations. Typical arrester ratings include maximum continuous operating voltage (MCOV), expressed in rms volts, and the maximum discharge voltage for several standard situations. The final rating involves the energy absorption capability.

Primary distribution arresters are classified for station, intermediate, distribution (heavy duty), and distribution (light duty). Applicable standards for surge protection include IEEE Std. C62.11 and ANSI C92.1.

The arrester *MCOV* is chosen to be near the maximum expected short-term line-to-ground voltage. The worst-case short-term line voltage is often set by conditions during unbalanced faults. The voltage present on the unfaulted phase is influenced by the distribution system grounding practices—particularly the ratio of zero-sequence impedance to positive-sequence impedance. Unfaulted phases on effectively grounded systems will experience little line-to-ground voltage rise during single-phase faults, whereas the line-to-ground voltage will rise to full line–line levels during a single-phase fault on an ungrounded or high-impedance grounded system. The higher *MCOV* on these systems also raises the discharge voltages, resulting in higher insulation requirements for ungrounded and high-impedance grounded systems.

Within its energy rating, the surge protective device will divert the lightning surge to ground while clamping the voltage at some level. Following surge diversion, the device will return to the nonconducting state. With the clamping voltage below the BIL of the system equipment, there should be no damage and the line can remain in service.

Fault Protection

Primary distribution lines are subject to faults (short circuits). These faults result in high current flow to the fault, at levels that will cause damage if not interrupted quickly. Fault types are:

- Three-phase
- Single-phase to ground
- Two-phase
- Two-phase to ground

These fault types are illustrated in Fig. 14. On overhead lines, the majority of faults involve arcing in air, and many (perhaps 70% to 80%) are temporary. When the fault is cleared by a protecting device, the arc is extinguished with no equipment damage, and the circuit can be successfully reenergized. When this is done automatically, the customer on the cleared section experiences a short interruption of approximately 1 s. Faults on underground lines, however, involve damage of the solid line insulation, and typically are permanent. Distribution faults, particularly single-line to ground faults, are subject to high fault impedances, lowering fault currents and making fault sensing more difficult. A well-designed overcurrent protection system will detect and clear the large majority of faults. Still, some faults may occur that do not create overcurrents and will not be detected through this means. An example of this would be a distribution line that has broken and fallen onto snow or dry asphalt. Dependable detection of this situation is a question that remains under active consideration (11).

Fault sensing on effectively grounded radial distribution systems is done with overcurrent relays (instantaneous and time overcurrent) and fuses. Radial systems with no reverse current flow have no need for directional elements. Distance protection is available, and can be useful as a fault detector. References 12,13,14,15,16 provide fuller discussions of distribution-line protection. Several of these provide comprehensive coverage of power-system protection, including generators, motors, transformers, buses, and transmission lines.

Current transformers (*CTs*) are placed in each phase of the line to sense the line current. Typically, either two or three phase relays and a residual relay are fed by a set of *CTs*, as shown in Fig. 15. The residual relay will sense the sum of the three phase currents, which is the portion of those currents that will flow into ground (three times the zero-sequence current at that point). When the residual relay is depended on to sense

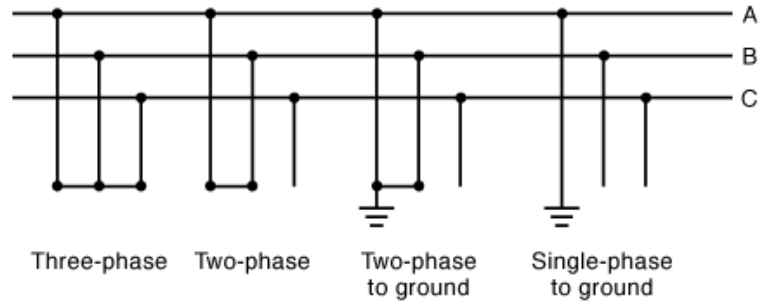


Fig. 14. The four types of shunt faults.

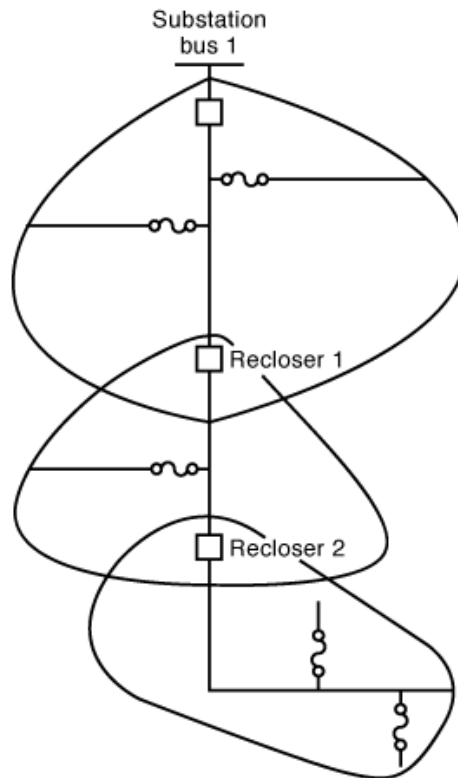


Fig. 15. Distribution-feeder one-line diagram showing overlapping zones of protection for the feeder head breaker and two line reclosers.

single-phase to ground faults, two phase relays are sufficient, as at least one of these will be involved in any two-phase or three-phase fault.

The distribution line is divided into zones of protection. A circuit breaker or recloser will be located at the feeder head, and will protect the initial portions of the feeder. The reach of this protection is determined through a comparison of the relay phase and residual current setting and the fault currents along the line. The next protective device must be placed so that the zones overlap. An illustration of a distribution feeder with overlapping zones is shown in Fig. 16.

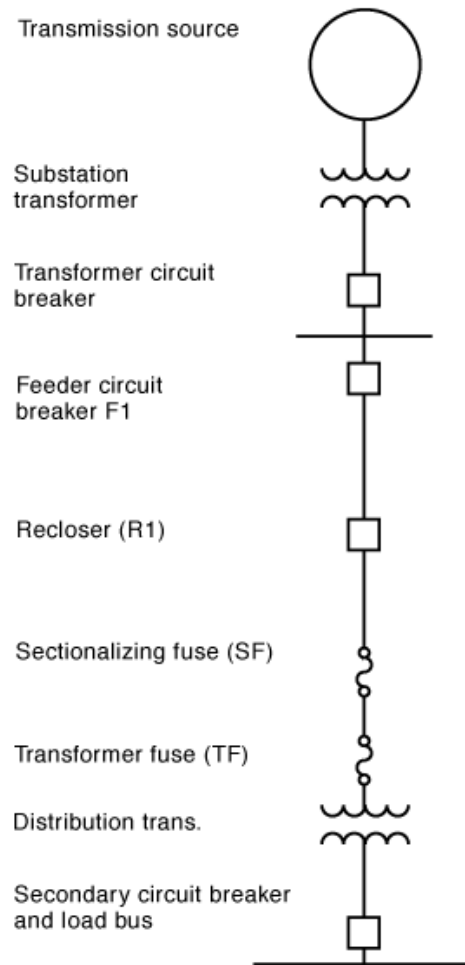


Fig. 16. Feeder portion, showing the protective devices in series above a particular load site.

The main feeder consists of high-capacity three-phase line. Taps or laterals will feed local load, and are often single-phase. As it is undesirable for faults on the laterals to cause an outage of the main feeder, sectionalizing fuses are commonly placed at the point where the lateral branches off of the main feeder. Fuses are not placed on the main feeder, however. Reclosers are placed in the main feeder, and provide sensing and reclosing of faults beyond that point. They also avoid single-phasing, which occurs when one fuse operates out of a set of three. Single-phasing puts all downstream three-phase motors at risk, and should be avoided.

Selectivity between protective devices is obtained through coordinating the time delay between devices so that the downstream device will respond more quickly than the upstream device. Fuses, reclosers, and relays have variable time–current characteristics, with quicker response at increasing fault current. Figure 17 shows an example feeder with substation transformer, feeder head breaker, line recloser, sectionalizing fuse, and distribution transformer fuse. Maximum (bolted) fault currents at each location are shown on the diagram. Representative time–current curves for these devices are shown in Fig. 18. Figure 18 shows coordination between downstream and upstream devices so that the downstream device will sense and clear the fault prior to the sensing of the fault by the upstream device.

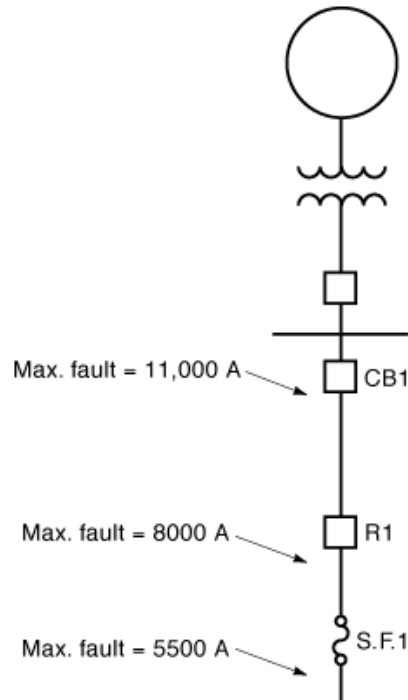


Fig. 17. Feeder coordination one-line diagram showing maximum fault levels.

On overhead distribution lines, it is possible to provide protection that will retain service to the entire feeder for temporary faults and minimize the system outage for permanent faults through a combination of fast and slow tripping by the reclosers commonly known as *fuse saving*. With fuse saving, a recloser fast trip is set to clear a fault before a sectionalizing fuse can operate. A fault anywhere on the line will be cleared by the upstream recloser. After a short time delay, a reclose is initiated, reenergizing the feeder. If the fault is temporary, all customers are returned to service. If the fault is permanent, however, fault current will again flow. The recloser timing is switched to a slow curve, allowing fuse clearing if the fault is on a fused lateral. In this case, only the customers on that lateral will experience an outage. If the fault is on the main feeder, however, the recloser will by necessity clear the fault. All customers downstream of that recloser will experience an outage due to this permanent fault. As the majority of faults are temporary, and also many feeders have more exposure on laterals than on main feeder paths, the number of customers experiencing outages can be greatly reduced by this procedure.

Power Quality

Power quality issues fall into two basic categories: steady-state voltage issues and momentary events. Such issues are of increasing interest, poor quality being blamed for load disruption and equipment damage. The expanding presence of sensitive electronic loads is a major factor in the recent importance of power quality.

Steady-State Voltage Quality. Theoretically, steady-state voltage issues include magnitude, frequency, and waveshape. Frequency is seldom a problem in the interconnected power system, and voltage magnitude is considered an aspect of power control (see the section “Steady-State Operation” above). Waveshape

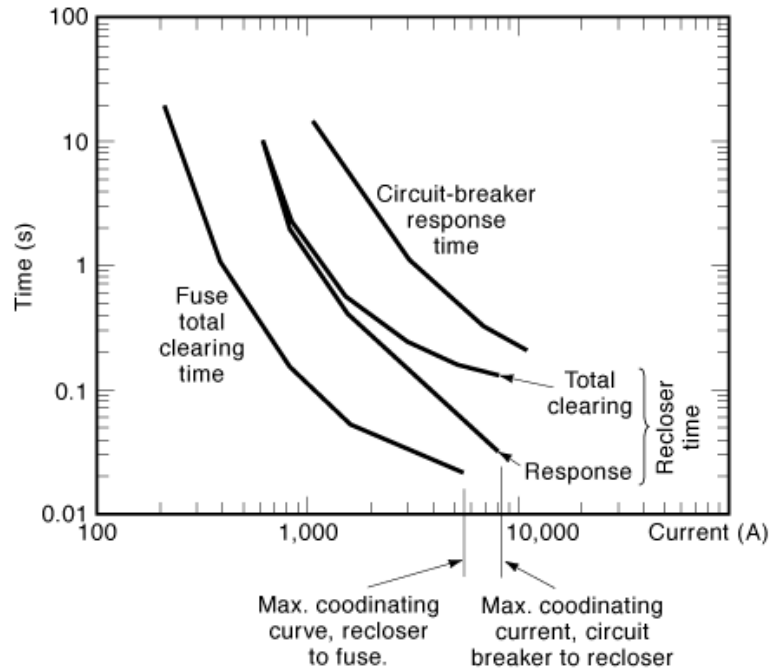


Fig. 18. Time-current curve showing recloser-fuse and circuit-breaker-recloser coordination.

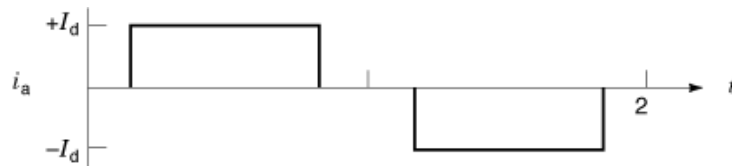


Fig. 19. Idealized waveform of a three-phase line commutated converter.

issues are the key steady-state power quality concern. Waveshape distortion can be due to harmonic distortion (distortion at an integer multiple of the fundamental) or interharmonic distortion (steady signals at nonharmonic frequencies).

Harmonic Generation. A major source of harmonics on the power system is electronic converters. Diode and thyristor rectifiers feeding inductive loads draw square-wave currents from the system; the ideal waveshape of a full-wave three-phase rectifier is shown in Fig. 19. The Fourier series expression of the waveshape of Fig. 19 is

$$i(t) = \sum_{n=6k\pm 1} \sqrt{2} \frac{I_1}{n} \sin(n\omega_1 t + \phi_n)$$

where $k = 1, 2, \dots$, I_1 is the rms fundamental current, and $f_1 = \omega_1/2\pi$ is the fundamental frequency. The rms or effective value of the n th harmonic is $I_n = I_1/n$. Single-phase rectifiers draw a similar current spectrum, but include the odd triplen harmonics. Half-wave rectifiers or similar circuits drawing dc currents and even harmonics are detrimental to system equipment and are strongly discouraged.

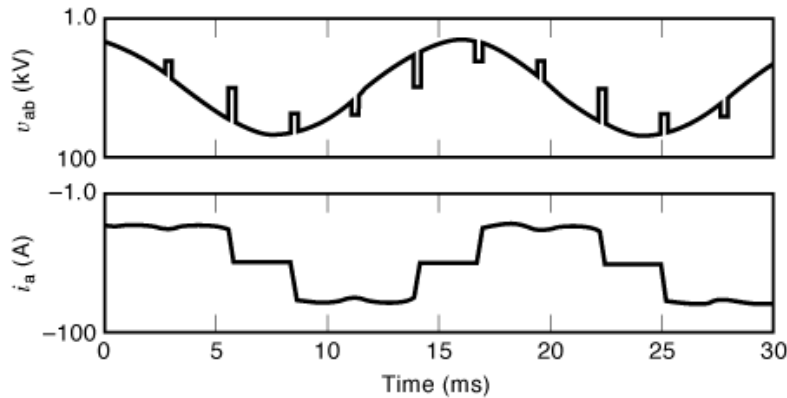


Fig. 20. Line–line voltage and line current for a three-phase controlled rectifier, showing line notching during the current commutation cycles.

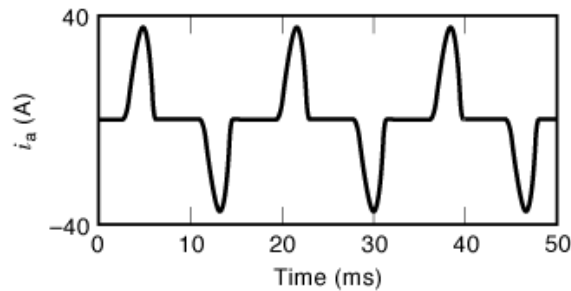


Fig. 21. Typical current drawn by a single-phase diode rectifier feeding a dc link capacitor.

Harmonic current or voltage distortion is often described by the total harmonic distortion (*THD*), given by

$$\text{THD} = \frac{\sqrt{\sum_{n=2}^{\infty} F_n}}{F_1} \times 100\%$$

F_1 is the fundamental rms voltage or current, and F_n is the corresponding rms level of the harmonic in question.

These rectifiers are also subject to voltage notching, which occurs during the commutation of the phase current. A typical notched-voltage wave is shown in Fig. 20 (17).

Diode rectifiers supplying a dc link having a smoothing capacitor can draw a line current with the waveshape shown in Fig. 21. This situation is common in electronic equipment, where a second switching converter takes its feed from the dc link capacitor. *THD* levels for these line-side rectifiers can exceed 100%, with low-order harmonics approaching the level of the fundamental. It is not unusual for larger rectifiers of this type to cause load shutdowns when misapplied.

The rectifiers described above are all line-commutated—with diodes or thyristors switching once per cycle. A recent option is to utilize self-commutated line-side converters, which switch at high frequencies to construct a smoother waveshape (18). These converters are sometimes referred to as unity-power-factor converters, as the current drawn is nearly sinusoidal and is in phase with the voltage. They do, however, contain some current

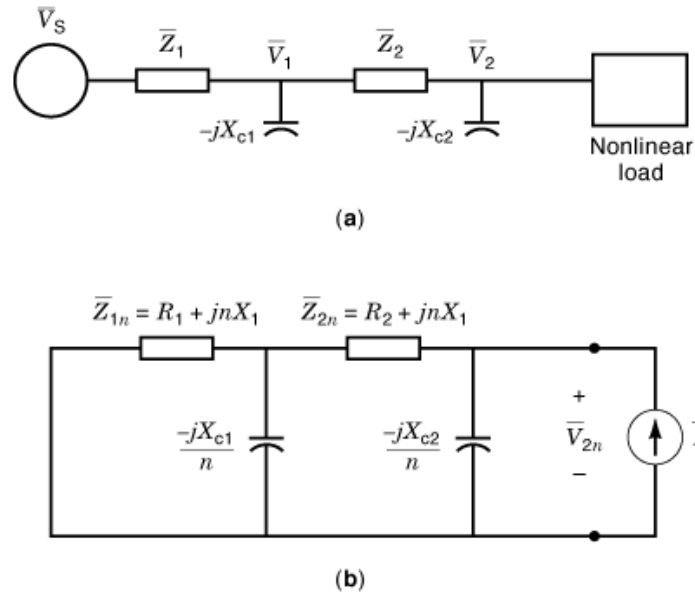


Fig. 22. One-line diagram of a power system with a nonlinear load, with its corresponding harmonic equivalent circuit: (a) one-line diagram showing 60 Hz voltages and impedances; (b) n th-harmonic per-phase diagram, showing harmonic current injection by the nonlinear load.

at the switching frequency, which can range up into the hundreds of kilohertz in low-power applications. Recent standards (such as IEC 61000-3-2) encourage this type of line-side converter for personal computers and other electronic equipment of similar size.

Harmonic Propagation. Harmonic currents are injected onto the power system by certain classes of load, as described in the preceding sub-subsection. At a given harmonic frequency, the power system can be modeled as an *RLC* network, with series inductance and shunt capacitance dominating the system performance (19). Figure 22 shows the one-line diagram of a radial distribution system, along with a circuit diagram representing this system at the n th harmonic. As is typical, impedance values in this diagram are given per unit at 60 Hz, with the corresponding harmonic impedance increasing (decreasing) proportionally to the harmonic number for inductance (capacitance).

The capacitance–inductance combination will lead to system resonance. A frequency scan for the circuit of Fig. 22 is shown in Fig. 23. When these resonant frequencies coincide with frequencies where harmonic currents are injected, harmonic overvoltages will occur. Current multiplication also occurs, causing system current flows to be much greater than those injected by the harmonic source.

IEEE Std. 519-1992 (20) recommends a voltage limit of 5% *THD* for general distribution systems, for example. Additional limits for individual harmonics and for other systems are also given. Excessive harmonic voltages are most often alleviated through the application of harmonic filters on either the primary or the secondary voltage level.

Harmonic Effects. High harmonic levels lead to equipment heating and derating. Operation of equipment can be affected, and equipment can experience insulation stress. I^2R heating effects are compounded by skin effect, causing more heat per ampere at increasing frequencies. Capacitors, having lower impedance at higher frequencies, often seem to “attract” harmonic currents. As a result, capacitor fuse blowing is often an early indication of excessive harmonic levels.

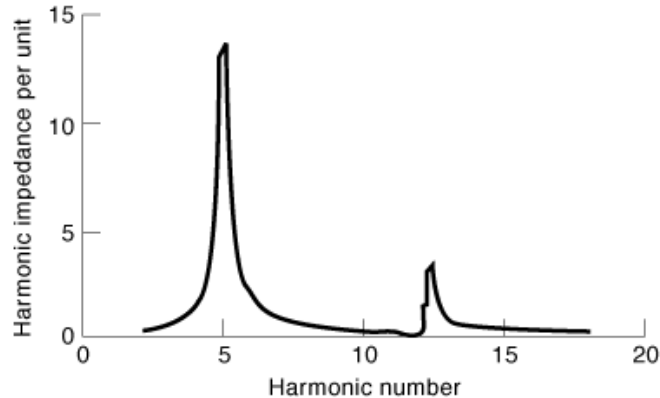


Fig. 23. Frequency scan of the harmonic impedance $\bar{V} \bar{V}_{2n} / \bar{I} \bar{I}_n$.

High harmonic content can also lead to a number of equipment malfunctions and operating problems. Some types of energy meters have incorrect response at harmonic frequencies, leading to errors. Some loads rely on voltage waveshape for their operation. Some digital clocks, for example, function by counting the zero crossings of the voltage waves. Distorted voltage waves with multiple zero crossings per cycle cause these clocks to function unreliably. Reference 21 provides an additional discussion of equipment problems that can result from high harmonic levels.

Momentary Events. Momentary power quality problems are classified as sags, swells, impulses, momentary interruptions, and flicker.

- A *sag* is a momentary reduction in the 60 Hz voltage.
- A *swell* is a momentary increase in the 60 Hz voltage.
- An *impulse* is a short-term (subcycle) increase or decrease in voltage, and can be either unidirectional or oscillatory.
- An *interruption* is a complete loss of voltage (alternatively, voltage below 10% of nominal).
- *Voltage flicker* involves the repetition of voltage sags, generally due to cyclic or intermittent loads.

Long-term interruptions are generally classified as a reliability problem rather than a power quality problem. An interruption in the range of 2 to 5 min is a commonly accepted boundary between a momentary interruption and a long-term interruption. A similar time boundary separates sags and swells from steady-state voltage problems.

Momentaries result from a variety of sources. These include:

- Power-system faults (sags/swells).
- Lightning (unidirectional impulses).
- Switching surges (unidirectional or oscillatory impulses).
- Inrush current (sags, oscillatory impulses, flicker).

Power-system faults are the most common cause of momentary power quality problems. Depending on location and severity, faults can cause voltage sags over a widespread area. Figure 24 shows the one-line diagram of a distribution system experiencing a fault close to the substation bus. In this figure, loads fed by the faulted feeder will experience an outage due to the circuit-breaker clearing of the fault. Loads on

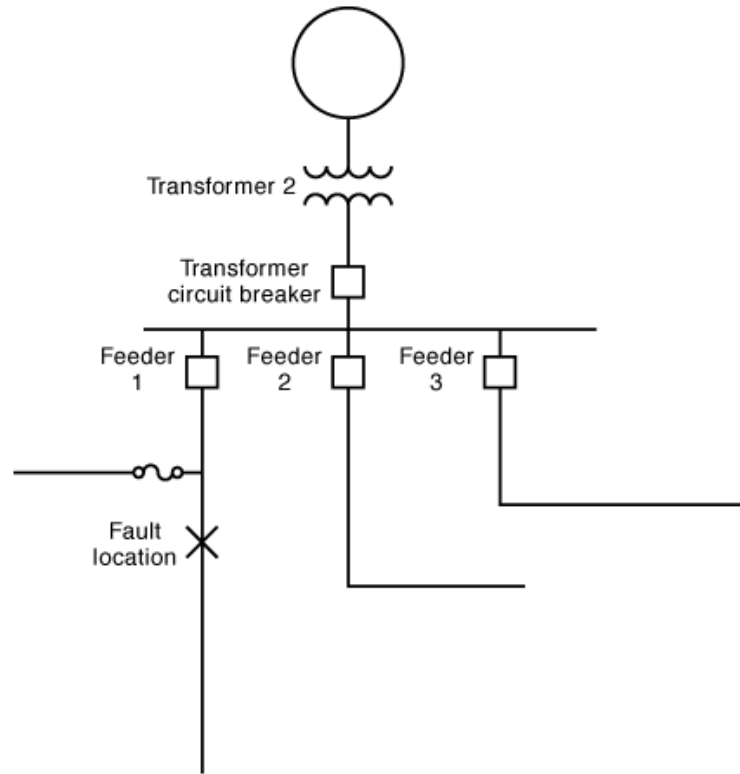


Fig. 24. The one-line diagram of a distribution system with a fault on feeder 1.

the other feeders will experience a voltage sag while the fault is on. If the fault is temporary, the circuit breaker will reclose successfully and loads on the faulted feeder will experience a momentary outage. If the fault is permanent, however, the circuit breaker will trip again and will proceed to lock out, resulting in a long-term interruption (outage) on that feeder. Loads on the adjacent feeders will experience one sag for the temporary fault. In the case of a permanent fault, voltage on the adjacent feeders will sag on the initial fault and also on each reclose of the circuit breaker. These customers, therefore, will favor minimizing the number of reclose attempts. In particular, the practice of fuse saving described in the section “Fault Protection” is being reevaluated in situations where sensitive loads are prevalent.

A voltage sag is characterized by its depth and its duration. The various loads respond differently to different sags—for example, in a combination of a computer and a motor contactor, the motor contactor might ride through one sag that causes a computer crash, and the computer might ride through the next sag, which causes a contactor dropout. Three-phase loads complicate the matter further by responding according to the number of phases that sag during a given fault.

One prominent measure of momentary voltage events is the “Orange Book” (22) curve. This curve represents a desirable ridethrough capability for computers and similar electronic loads. Disruption of computers involved in process control and database operations is often cited as being particularly prone to expensive downtime and recovery time.

Sensitive loads should be protected from these momentary events as appropriate to the load. Table 1 provides a list of amelioration devices along with some of the typical applications. A more comprehensive discussion can be found in Ref. 23.

Table 1: Amelioration Devices

Equipment Type	Provides Protection for	Typical Application
Metal oxide varistor (MOV)	Overvoltage impulses	Protection of computers against impulses due to lightning and switching
Uninterruptible power supply (UPS)—most often with storage batteries, sometimes with flywheel.	Voltage sags, momentary interruptions, and outages	Computers—can provide ride through sags and momentaries, allows orderly shutdown on extended outages
Capacitors	Voltage sags	Storage capacitors can provide ridethrough of sags, and some momentary-interruption ridethrough
Automatic throwover to alternate feed—mechanical or electric switching	Momentary interruptions and outages	Production systems—can maintain service to high-power loads
Constant-voltage transformers Backup generation	Voltage sags Outages	No energy storage; good power capability Hospitals, etc., with stringent reliability requirements

There are several critical aspects to the successful implementation of this equipment. These include:

- Identifying the root cause of the quality problem
- Accurate assessment of costs of load disruption
- Knowledge of the occurrence rate of disruption
- Provision of appropriate equipment that will economically solve the target problem(s)
- Proper installation of the equipment
- Maintenance to ensure reliable operation

Lack of attention to any one of these issues can lead to poor performance or an overly expensive installation.

Recent advances in power electronics have led to the development of advanced devices that provide voltage support, harmonic filtering, and impulse protection (24).

Special Situations

Distribution-Based Generation. Power generators located on the distribution system will affect the operation and performance of the system. Recent changes in technology and the regulatory environment have led to increasing instances of distribution-based generation. Safety is the first consideration in dealing with distribution systems hosting power generation. Many of the operating practices on radial systems depend on the distribution substation being the only source of energy on the system. Distribution based generation can lead to several problems if not properly interfaced with the system. These include:

- Personnel safety during equipment repair
- Islanding
- Backfeeding faults

Personnel safety is of primary concern. Utility lockout and tagout procedures are difficult and time-consuming to implement when generation and associated switching equipment are not utility-owned. Fault backfeeding occurs, as the generation will supply current to a fault. This may cause a need for directional sensing in line overcurrent relays to prevent relay tripping on remote faults. Perhaps more importantly, fault current from the generator may continue following the operation of the feeder circuit breaker intended to clear the fault. This will extend the duration of faults. On arcing (temporary) faults, the circuit breaker will find the fault still on in cases where the generator is backfeeding the fault through the reclosing delay time. This will prevent successful reclosure of the circuit.

Islanding will occur if the generator remains on line following loss of source energy. The resulting generation–load mismatch will lead to frequency and voltage problems. Also, there may be a potential for ferroresonance problems. Finally, synchronization problems will exist if circuit reclosure is attempted with the generator on line.

Through proper design, these issues can be resolved. It is not, however, a trivial task, and the interface requirements must be addressed at project initiation rather than as the installation date approaches (25).

Arcing loads. Loads such as arc furnaces and arc welders will produce random fluctuations in voltage, which can seriously affect adjacent loads. This is a complex problem, which depends on the size of the polluting load, the strength of the power system, and the sensitivity of adjacent loads. Power-factor correction capacitors and static var compensators are among the solutions to voltage flicker problems of this type. Reference 26 provides a more in-depth assessment of this problem.

Distribution Automation

Recent computer and communications advances are allowing an evaluation of distribution automation. There are a number of areas of the current electric power distribution network that are candidates for automation. A partial list of these includes (27):

- Automatic meter reading
- Adjustable-rate implementation
- Remote operation of sectionalizing switches
- Coordinated operation of capacitor banks
- Line reconfiguration to minimize losses
- Overload alleviation
- Rapid outage detection
- Voltage quality monitoring

These projects offer a combination of cost saving and service upgrades.

A primary cost of distribution automation is for the communication system. Communication options include wireless, fiber optic, communication line, and power line. Options involving communication nodes at customer metering sites obviously require more transmitter–receivers than systems requiring nodes only at utility switching locations.

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