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Fundamentals of Distribution Systems

Electrification in the early 20th century dramatically improved productivity and increased the well-being of the industrialized world. No longer a luxury — now a necessity — electricity powers the machinery, the computers, the health-care systems, and the entertainment of modern society. Given its benefits, electricity is inexpensive, and its price continues to slowly decline (after adjusting for inflation — see Figure 1.1).

Electric power distribution is the portion of the power delivery infrastructure that takes the electricity from the highly meshed, high-voltage transmission circuits and delivers it to customers. Primary distribution lines are "medium-voltage" circuits, normally thought of as 600 V to 35 kV. At a distribution substation, a substation transformer takes the incoming transmission-level voltage (35 to 230 kV) and steps it down to several distribution primary circuits, which fan out from the substation. Close to each end user, a distribution transformer takes the primary-distribution voltage and steps it down to a low-voltage secondary circuit (commonly 120/240 V; other utilization voltages are used as well). From the distribution transformer, the secondary distribution circuits connect to the end user where the connection is made at the service entrance. Figure 1.2 shows an overview of the power generation and delivery infrastructure and where distribution fits in. Functionally, distribution circuits are those that feed customers (this is how the term is used in this book, regardless of voltage or configuration). Some also think of distribution as anything that is radial or anything that is below 35 kV.

The distribution infrastructure is extensive; after all, electricity has to be delivered to customers concentrated in cities, customers in the suburbs, and customers in very remote regions; few places in the industrialized world do not have electricity from a distribution system readily available. Distribution circuits are found along most secondary roads and streets. Urban construction is mainly underground; rural construction is mainly overhead. Suburban structures are a mix, with a good deal of new construction going underground.

A mainly urban utility may have less than 50 ft of distribution circuit for each customer. A rural utility can have over 300 ft of primary circuit per customer.

Several entities may own distribution systems: municipal governments, state agencies, federal agencies, rural cooperatives, or investor-owned utili-

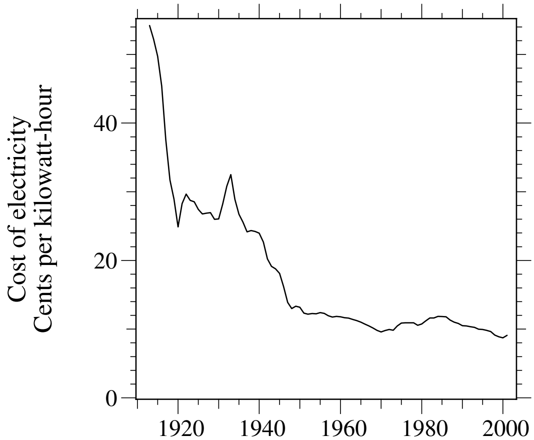

FIGURE 1.1
Cost of U.S. electricity adjusted for inflation to year 2000 U.S. dollars. (Data from U.S. city average electricity costs from the U.S. Bureau of Labor Statistics.)

ties. In addition, large industrial facilities often need their own distribution systems. While there are some differences in approaches by each of these types of entities, the engineering issues are similar for all.

For all of the action regarding deregulation, the distribution infrastructure remains a natural monopoly. As with water delivery or sewers or other utilities, it is difficult to imagine duplicating systems to provide true competition, so it will likely remain highly regulated.

Because of the extensive infrastructure, distribution systems are capital-intensive businesses. An Electric Power Research Institute (EPRI) survey found that the distribution plant asset carrying cost averages 49.5% of the total distribution resource (EPRI TR-109178, 1998). The next largest component is labor at 21.8%, followed by materials at 12.9%. Utility annual distribution budgets average about 10% of the capital investment in the distribution system. On a kilowatt-hour basis, utility distribution budgets average 0.89 cents per kilowatt-hour (see Table 1.1 for budgets shown relative to other benchmarks).

Low cost, simplification, and standardization are all important design characteristics of distribution systems. Few components and/or installations are individually engineered on a distribution circuit. Standardized equipment and standardized designs are used wherever possible. "Cookbook" engineering methods are used for much of distribution planning, design, and operations.

Distribution planning is the study of future power delivery needs. Planning goals are to provide service at low cost and high reliability. Planning requires a mix of geographic, engineering, and economic analysis skills. New circuits (or other solutions) must be integrated into the existing distribution system within a variety of economic, political, environmental, electrical, and geographic constraints. The planner needs estimates of load

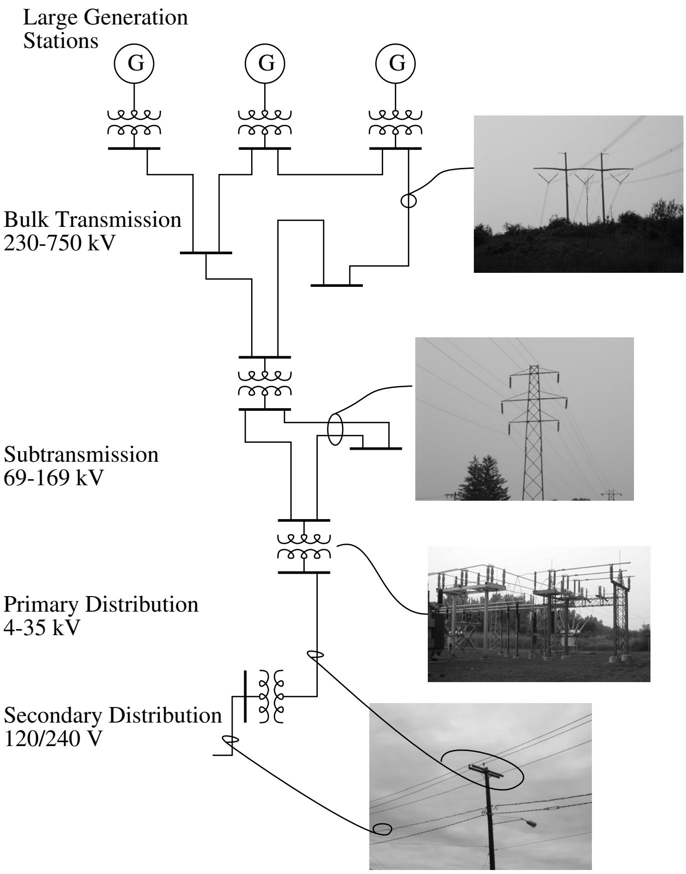

FIGURE 1.2
Overview of the electricity infrastructure.

TABLE 1.1

Surveyed Annual Utility Distribution Budgets in U.S. Dollars

	Average	Range
Per dollar of distribution asset	0.098	0.0916–0.15
Per customer	195	147–237
Per thousand kWH	8.9	3.9–14.1
Per mile of circuit	9,400	4,800–15,200
Per substation	880,000	620,000–1,250,000

Source: EPRI TR-109178, *Distribution Cost Structure — Methodology and Generic Data*, Electric Power Research Institute, Palo Alto, CA, 1998.

growth, knowledge of when and where development is occurring, and local development regulations and procedures. While this book has some material that should help distribution planners, many of the tasks of a planner, like load forecasting, are not discussed. For more information on distribution planning, see Willis's *Power Distribution Planning Reference Book* (1997), IEEE's *Power Distribution Planning* tutorial (1992), and the *CEA Distribution Planner's Manual* (1982).

1.1 Primary Distribution Configurations

Distribution circuits come in many different configurations and circuit lengths. Most share many common characteristics. Figure 1.3 shows a "typical" distribution circuit, and Table 1.2 shows typical parameters of a distribution circuit. A *feeder* is one of the circuits out of the substation. The main feeder is the three-phase backbone of the circuit, which is often called the *mains* or *mainline*. The mainline is normally a modestly large conductor such as a 500- or 750-kcmil aluminum conductor. Utilities often design the main feeder for 400 A and often allow an emergency rating of 600 A. Branching from the mains are one or more *laterals*, which are also called taps, lateral taps, branches, or branch lines. These laterals may be single-phase, two-phase, or three-phase. The laterals normally have fuses to separate them from the mainline if they are faulted.

The most common distribution primaries are four-wire, multigrounded systems: three-phase conductors plus a multigrounded neutral. Single-phase loads are served by transformers connected between one phase and the neutral. The neutral acts as a return conductor and as an equipment safety ground (it is grounded periodically and at all equipment). A single-phase line has one phase conductor and the neutral, and a two-phase line has two phases and the neutral. Some distribution primaries are three-wire systems (with no neutral). On these, single-phase loads are connected phase to phase, and single-phase lines have two of the three phases.

There are several configurations of distribution systems. Most distribution circuits are radial (both primary and secondary). Radial circuits have many advantages over networked circuits including

- Easier fault current protection
- Lower fault currents over most of the circuit
- Easier voltage control
- Easier prediction and control of power flows
- Lower cost

Distribution primary systems come in a variety of shapes and sizes (Figure 1.4). Arrangements depend on street layouts, the shape of the area covered

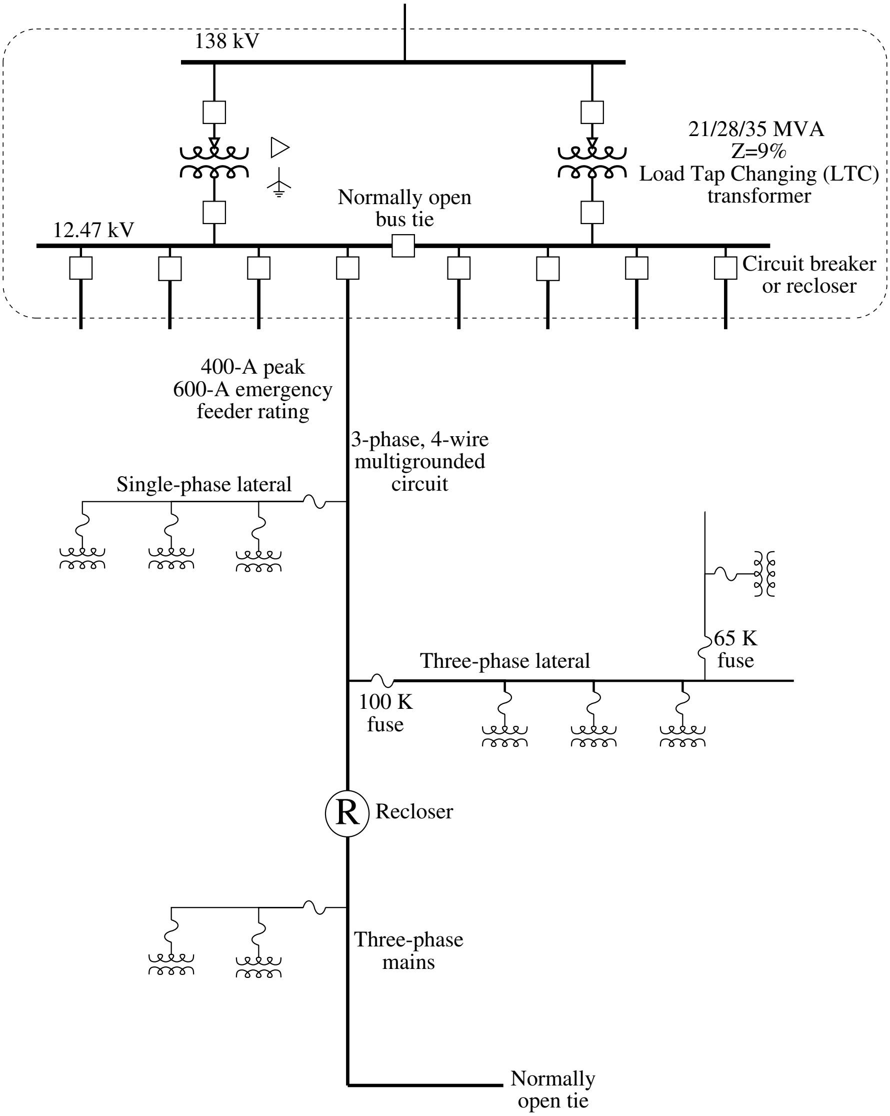

FIGURE 1.3
Typical distribution substation with one of several feeders shown (many lateral taps are left off). (Copyright © 2000. Electric Power Research Institute. 1000419. *Engineering Guide for Integration of Distributed Generation and Storage Into Power Distribution Systems.* Reprinted with permission.)

TABLE 1.2

Typical Distribution Circuit Parameters

	Most Common Value	Other Common Values
Substation characteristics		
Voltage	12.47 kV	4.16, 4.8, 13.2, 13.8, 24.94, 34.5 kV
Number of station transformers	2	1–6
Substation transformer size	21 MVA	5–60 MVA
Number of feeders per bus	4	1–8
Feeder characteristics		
Peak current	400 A	100–600 A
Peak load	7 MVA	1–15 MVA
Power factor	0.98 lagging	0.8 lagging–0.95 leading
Number of customers	400	50–5000
Length of feeder mains	4 mi	2–15 mi
Length including laterals	8 mi	4–25 mi
Area covered	25 mi^2	0.5–500 mi^2
Mains wire size	500 kcmil	4/0–795 kcmil
Lateral tap wire size	1/0	#4–2/0
Lateral tap peak current	25 A	5–50 A
Lateral tap length	0.5 mi	0.2–5 mi
Distribution transformer size (1 ph)	25 kVA	10–150 kVA

by the circuit, obstacles (like lakes), and where the big loads are. A common suburban layout has the main feeder along a street with laterals tapped down side streets or into developments. Radial distribution feeders may also have extensive branching — whatever it takes to get to the loads. An *express feeder* serves load concentrations some distance from the substation. A three-phase mainline runs a distance before tapping loads off to customers. With many circuits coming from one substation, a number of the circuits may have express feeders; some feeders cover areas close to the substation, and express feeders serve areas farther from the substation.

For improved reliability, radial circuits are often provided with normally open tie points to other circuits as shown in Figure 1.5. The circuits are still operated radially, but if a fault occurs on one of the circuits, the tie switches allow some portion of the faulted circuit to be restored quickly. Normally, these switches are manually operated, but some utilities use automated switches or reclosers to perform these operations automatically.

A primary-loop scheme is an even more reliable service that is sometimes offered for critical loads such as hospitals. Figure 1.6 shows an example of a primary loop. The key feature is that the circuit is “routed through” each

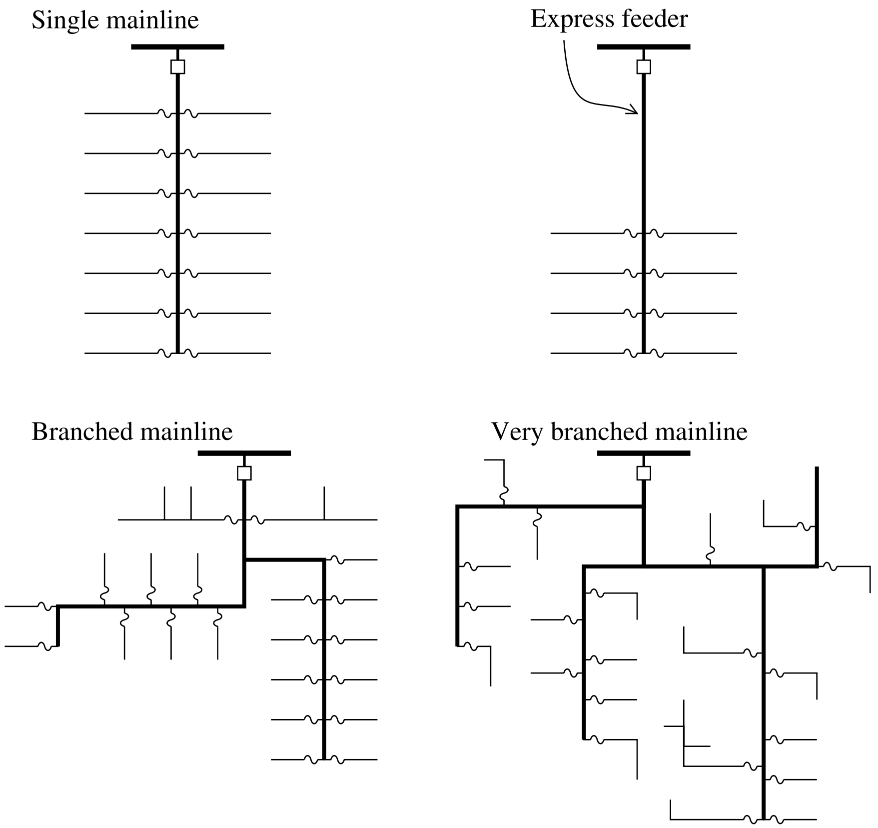

FIGURE 1.4
Common distribution primary arrangements.

critical customer transformer. If any part of the primary circuit is faulted, all critical customers can still be fed by reconfiguring the transformer switches.

Primary-loop systems are sometimes used on distribution systems for areas needing high reliability (meaning limited long-duration interruptions). In the open-loop design where the loop is left normally open at some point, primary-loop systems have almost no benefits for momentary interruptions or voltage sags. They are rarely operated in a closed loop. A widely reported installation of a sophisticated *closed* system has been installed in Orlando, FL, by Florida Power Corporation (Pagel, 2000). An example of this type of closed-loop primary system is shown in Figure 1.7. Faults on any of the cables in the loop are cleared in less than six cycles, which reduces the duration of the voltage sag during the fault (enough to help many computers). Advanced relaying similar to transmission-line protection is necessary to coordinate the protection and operation of the switchgear in the looped system. The relaying scheme uses a transfer trip with permissive over-reaching (the relays at each end of the cable must agree there is a fault

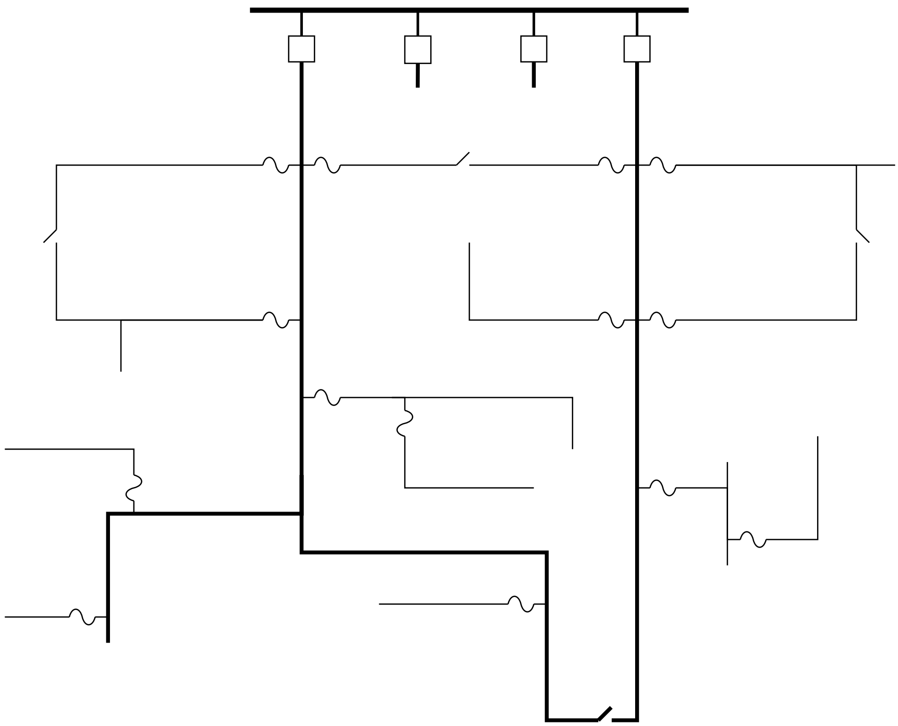

FIGURE 1.5
Two radial circuits with normally open ties to each other. (Copyright © 2000. Electric Power Research Institute. 1000419. *Engineering Guide for Integration of Distributed Generation and Storage Into Power Distribution Systems.* Reprinted with permission.)

between them with communications done on fiberoptic lines). A backup scheme uses directional relays, which will trip for a fault in a certain direction unless a blocking signal is received from the remote end (again over the fiberoptic lines).

Critical customers have two more choices for more reliable service where two primary feeds are available. Primary selective and secondary selective schemes both are normally fed from one circuit (see Figure 1.8). So, the circuits are still radial. In the event of a fault on the primary circuit, the service is switched to the backup circuit. In the primary selective scheme, the switching occurs on the primary, and in the secondary selective scheme, the switching occurs on the secondary. The switching can be done manually or automatically, and there are even static transfer switches that can switch in less than a half cycle to reduce momentary interruptions and voltage sags.

Today, the primary selective scheme is preferred mainly because of the cost associated with the extra transformer in a secondary selective scheme. The normally closed switch on the primary-side transfer switch opens after

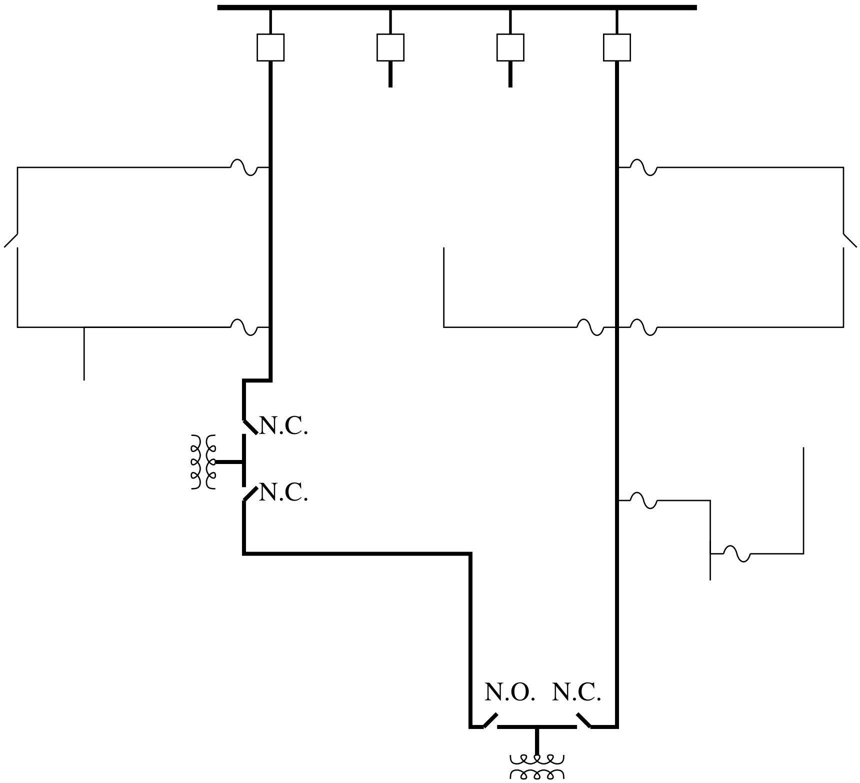

FIGURE 1.6
Primary loop distribution arrangement. (Copyright © 2000. Electric Power Research Institute. 1000419. *Engineering Guide for Integration of Distributed Generation and Storage Into Power Distribution Systems.* Reprinted with permission.)

sensing a loss of voltage. It normally has a time delay on the order of seconds — enough to ride through the distribution circuit's normal reclosing cycle. The opening of the switch is blocked if there is an overcurrent in the switch (the switch doesn't have fault interrupting capability). Transfer is also disabled if the alternate feed does not have proper voltage. The switch can return to normal through either an open or a closed transition; in a closed transition, both distribution circuits are temporarily paralleled.

1.2 Urban Networks

Some distribution circuits are not radial. The most common are the grid and spot secondary networks. In these systems, the secondary is networked together and has feeds from several primary distribution circuits. The spot

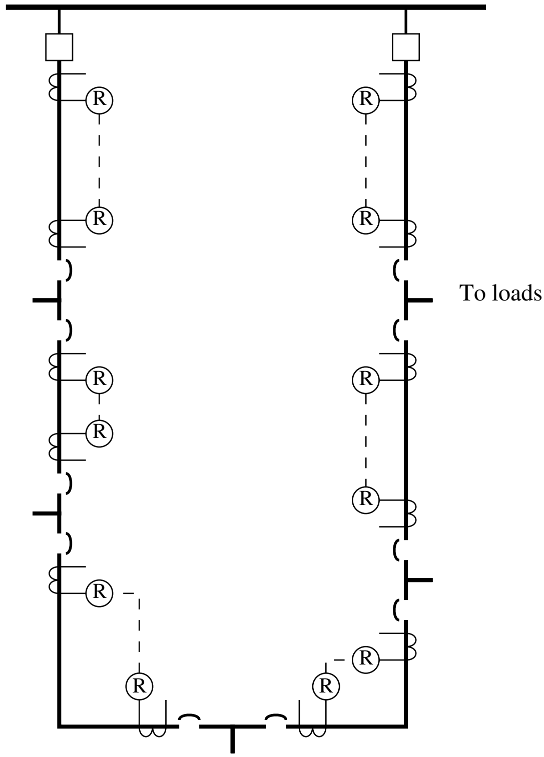

FIGURE 1.7
Example of a closed-loop distribution system.

network feeds one load such as a high-rise building. The grid network feeds several loads at different points in an area. Secondary networks are very reliable; if any of the primary distribution circuits fail, the others will carry the load without causing an outage for any customers.

The spot network generally is fed by three to five primary feeders (see Figure 1.9). The circuits are generally sized to be able to carry all of the load with the loss of either one or two of the primary circuits. Secondary networks have network protectors between the primary and the secondary network. A network protector is a low-voltage circuit breaker that will open when there is reverse power through it. When a fault occurs on a primary circuit, fault current backfeeds from the secondary network(s) to the fault. When this occurs, the network protectors will trip on reverse power. A spot network operates at 480Y/277 V or 208Y/120 V in the U.S.

Secondary grid networks are distribution systems that are used in most major cities. The secondary network is usually 208Y/120 V in the U.S. Five to ten primary distribution circuits (e.g., 12.47-kV circuits) feed the secondary network at multiple locations. Figure 1.10 shows a small part of a secondary network. As with a spot network, network protectors provide protection for faults on the primary circuits. Secondary grid networks can have peak loads

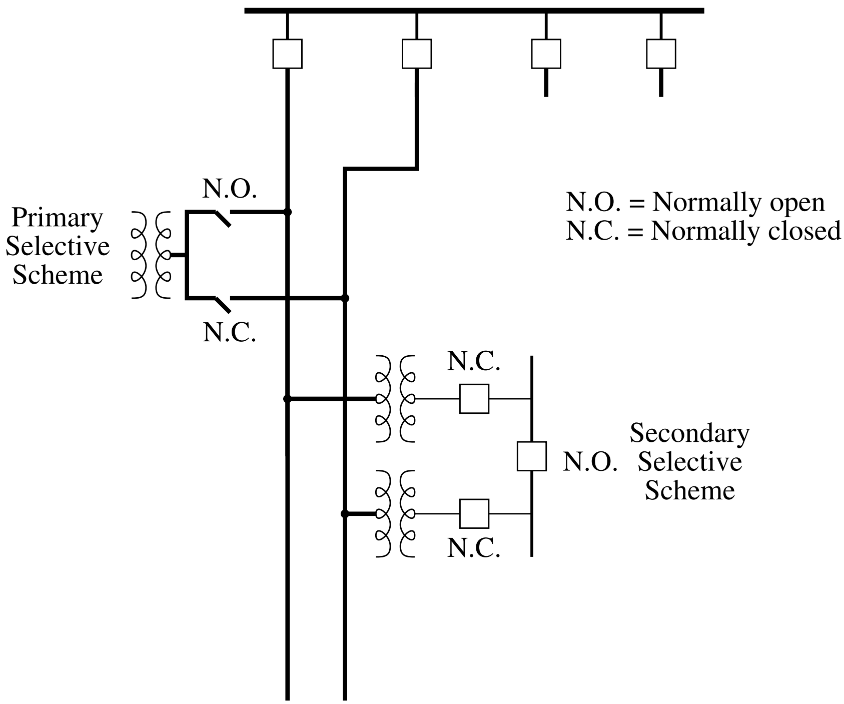

FIGURE 1.8
Primary and secondary selective schemes. (Copyright © 2000. Electric Power Research Institute. 1000419. *Engineering Guide for Integration of Distributed Generation and Storage Into Power Distribution Systems.* Reprinted with permission.)

of 5 to 50 MVA. Most utilities limit networks to about 50 MVA, but some networks are over 250 MVA. Loads are fed by tapping into the secondary networks at various points. Grid networks (also called street networks) can supply residential or commercial loads, either single or three phase. For single-phase loads, three-wire service is provided to give 120 V and 208 V (rather than the standard three-wire residential service, which supplies 120 V and 240 V).

Networks are normally fed by feeders originating from one substation bus. Having one source reduces circulating current and gives better load division and distribution among circuits. It also reduces the chance that network protectors stay open under light load (circulating current can trip the protectors). Given these difficulties, it is still possible to feed grid or spot networks from different substations or electrically separate buses.

The network protector is the key to automatic isolation and continued operation. The network protector is a three-phase low-voltage air circuit breaker with controls and relaying. The network protector is mounted on the network transformer or on a vault wall. Standard units are available with continuous ratings from 800 to 5000 A. Smaller units can interrupt 30 kA symmetrical, and larger units have interrupt ratings of 60 kA (IEEE Std.

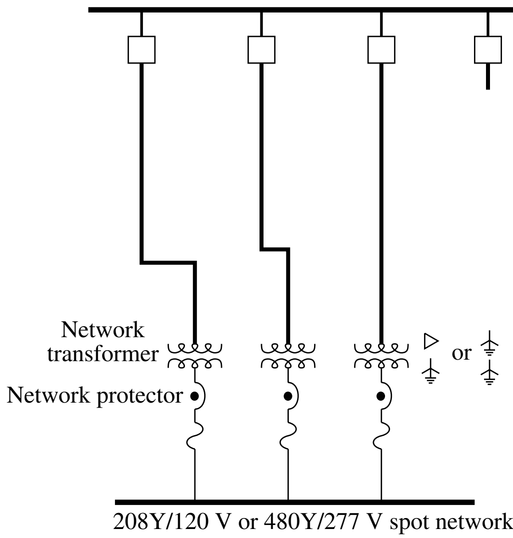

FIGURE 1.9
Spot network. (Copyright © 2000. Electric Power Research Institute. 1000419. *Engineering Guide for Integration of Distributed Generation and Storage Into Power Distribution Systems.* Reprinted with permission.)

C57.12.44–2000). A network protector senses and operates for reverse power flow (it does not have forward-looking protection). Protectors are available for either 480Y/277 V or 216Y/125 V.

The tripping current on network protectors can be changed, with low, nominal, and high settings, which are normally 0.05 to 0.1%, 0.15 to 0.20%, and 3 to 5% of the network protector rating. For example, a 2000-A network protector has a low setting of 1 A, a nominal setting of 4 A, and a high setting of 100 A (IEEE Std. C57.12.44–2000). Network protectors also have fuses that provide backup in case the network protector fails to operate, and as a secondary benefit, provide protection to the network protector and transformer against faults in the secondary network that are close.

The closing voltages are also adjustable: a 216Y/125-V protector has low, medium, and high closing voltages of 1 V, 1.5 V, and 2 V, respectively; a 480Y/277-V protector has low, medium, and high closing voltages of 2.2 V, 3.3 V, and 4.4 V, respectively.

1.3 Primary Voltage Levels

Most distribution voltages are between 4 and 35 kV. In this book, unless otherwise specified, voltages are given as line-to-line voltages; this follows normal industry practice, but it is sometimes a source of confusion. The four

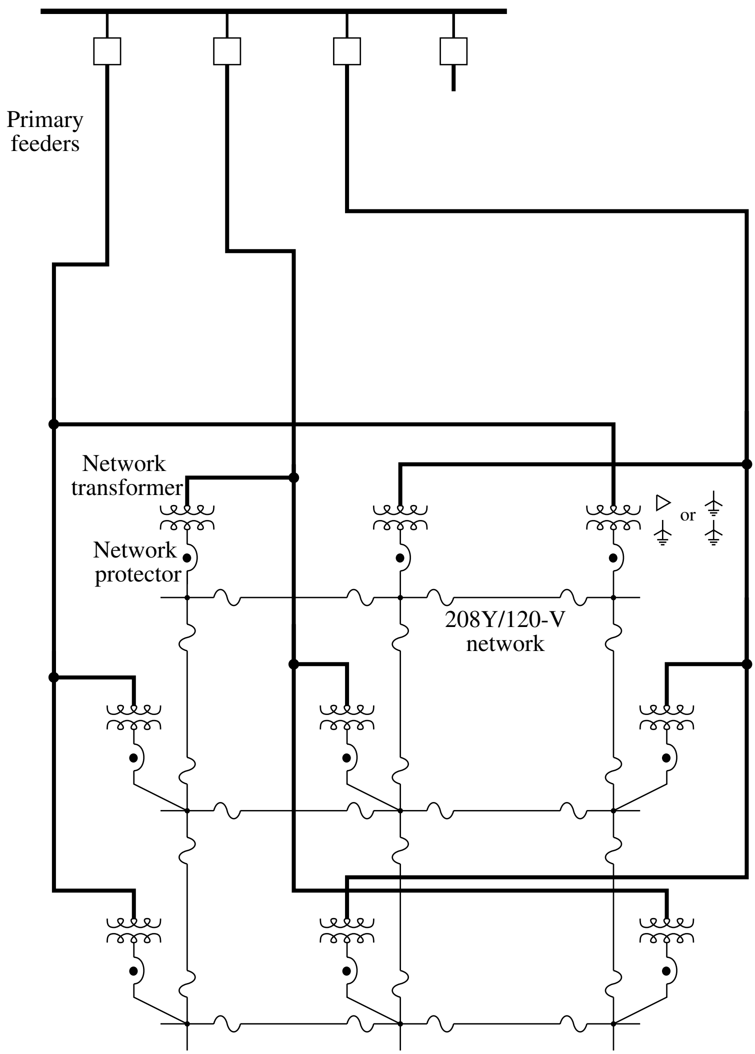

FIGURE 1.10
Portion of a grid network. (Copyright © 2000. Electric Power Research Institute. 1000419. *Engineering Guide for Integration of Distributed Generation and Storage Into Power Distribution Systems.* Reprinted with permission.)

major voltage classes are 5, 15, 25, and 35 kV. A voltage class is a term applied to a set of distribution voltages and the equipment common to them; it is not the actual system voltage. For example, a 15-kV insulator is suitable for application on any 15-kV class voltage, including 12.47 kV, 13.2 kV, and 13.8 kV. Cables, terminations, insulators, bushings, reclosers, and cutouts all have a voltage class rating. Only voltage-sensitive equipment like surge arresters, capacitors, and transformers have voltage ratings dependent on the actual system voltage.

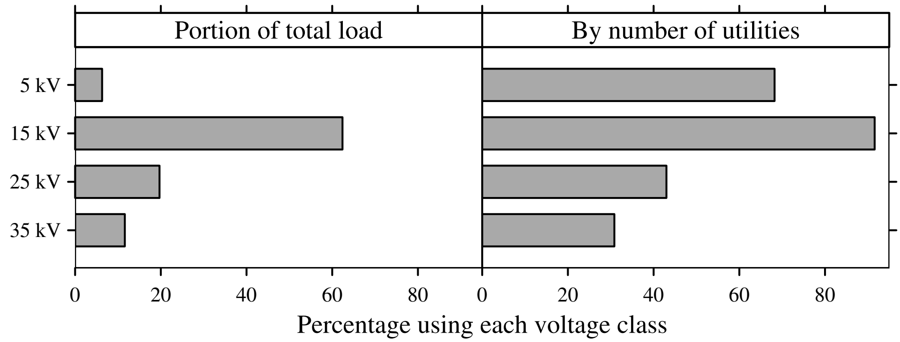

FIGURE 1.11
Usage of different distribution voltage classes (n = 107). (Data from [IEEE Working Group on Distribution Protection, 1995].)

Utilities most widely use the 15-kV voltages as shown by the survey results of North American utilities in Figure 1.11. The most common 15-kV voltage is 12.47 kV, which has a line-to-ground voltage of 7.2 kV.

The dividing line between distribution and subtransmission is often gray. Some lines act as both subtransmission and distribution circuits. A 34.5-kV circuit may feed a few 12.5-kV distribution substations, but it may also serve some load directly. Some utilities would refer to this as subtransmission, others as distribution.

The last half of the 20th century saw a move to higher voltage primary distribution systems. Higher-voltage distribution systems have advantages and disadvantages (see Table 1.3 for a summary). The great advantage of higher voltage systems is that they carry more power for a given current (Table 1.4 shows maximum power levels typically supplied by various distribution voltages). Less current means lower voltage drop, fewer losses, and more power-carrying capability. Higher voltage systems need fewer voltage

TABLE 1.3
Advantages and Disadvantages of Higher Voltage Distribution

Advantages	Disadvantages
Voltage drop — A higher-voltage circuit has less voltage drop for a given power flow.	*Reliability* — An important disadvantage of higher voltages: longer circuits mean more customer interruptions.
Capacity — A higher-voltage system can carry more power for a given ampacity.	*Crew safety and acceptance* — Crews do not like working on higher-voltage distribution systems.
Losses — For a given level of power flow, a higher-voltage system has fewer line losses.	*Equipment cost* — From transformers to cable to insulators, higher-voltage equipment costs more.
Reach — With less voltage drop and more capacity, higher voltage circuits can cover a much wider area.	
Fewer substations — Because of longer reach, higher-voltage distribution systems need fewer substations.	

TABLE 1.4

Power Supplied by Each Distribution Voltage for a Current of 400 A

System Voltage (kV)	Total Power (MVA)
4.8	3.3
12.47	8.6
22.9	15.9
34.5	23.9

regulators and capacitors for voltage support. Utilities can use smaller conductors on a higher voltage system or carry more power on the same size conductor. Utilities can run much longer distribution circuits at a higher primary voltage, which means fewer distribution substations. Some fundamental relationships are:

- *Power* — For the same current, power changes linearly with voltage.

$$P_2 = \frac{V_1}{V_1} P_1$$

  when $I_2 = I_1$

- *Current* — For the same power, increasing the voltage decreases current linearly.

$$I_2 = \frac{V_1}{V_2} I_1$$

  when $P_2 = P_1$

- *Voltage drop* — For the same power delivered, the percentage voltage drop changes as the ratio of voltages squared. A 12.47-kV circuit has four times the percentage voltage drop as a 24.94-kV circuit carrying the same load.

$$V_{\%2} = \left(\frac{V_1}{V_2}\right)^2 V_{\%1}$$

  when $P_2 = P_1$

- *Area coverage* — For the same load density, the area covered increases linearly with voltage: A 24.94-kV system can cover twice the area of a 12.47-kV system; a 34.5-kV system can cover 2.8 times the area of a 12.47-kV system.

$$A_2 = \frac{V_2}{V_1} A_1$$

where

V_1, V_2 = voltage on circuits 1 and 2

P_1, P_2 = power on circuits 1 and 2

I_1, I_2 = current on circuits 1 and 2

$V_{\%1}$, $V_{\%2}$ = voltage drop per unit length in percent on circuits 1 and 2

A_1, A_2 = area covered by circuits 1 and 2

The squaring effect on voltage drop is significant. It means that doubling the system voltage quadruples the load that can be supplied over the same distance (with equal percentage voltage drop); or, twice the load can be supplied over twice the distance; or, the same load can be supplied over four times the distance.

Resistive line losses are also lower on higher-voltage systems, especially in a voltage-limited circuit. Thermally limited systems have more equal losses, but even in this case higher voltage systems have fewer losses.

Line crews do not like higher voltage distribution systems as much. In addition to the widespread perception that they are not as safe, gloves are thicker, and procedures are generally more stringent. Some utilities will not glove 25- or 35-kV voltages and only use hotsticks.

The main disadvantage of higher-voltage systems is reduced reliability. Higher voltages mean longer lines and more exposure to lightning, wind, dig-ins, car crashes, and other fault causes. A 34.5-kV, 30-mi mainline is going to have many more interruptions than a 12.5-kV system with an 8-mi mainline. To maintain the same reliability as a lower-voltage distribution system, a higher-voltage primary must have more switches, more automation, more tree trimming, or other reliability improvements. Higher voltage systems also have more voltage sags and momentary interruptions. More exposure causes more momentary interruptions. Higher voltage systems have more voltage sags because faults further from the substation can pull down the station's voltage (on a higher voltage system the line impedance is lower relative to the source impedance).

Cost comparison between circuits is difficult (see Table 1.5 for one utility's cost comparison). Higher voltage equipment costs more — cables, insulators, transformers, arresters, cutouts, and so on. But higher voltage circuits can use smaller conductors. The main savings of higher-voltage distribution is fewer substations. Higher voltage systems also have lower annual costs from losses. As far as ongoing maintenance, higher voltage systems require less substation maintenance, but higher voltage systems should have more tree trimming and inspections to maintain reliability.

Conversion to a higher voltage is an option for providing additional capacity in an area. Conversion to higher voltages is most beneficial when substation

TABLE 1.5

Costs of 34.5 kV Relative to 12.5 kV

Item	Underground	Overhead
Subdivision without bulk feeders	1.25	1.13
Subdivision with bulk feeders	1.00	0.85
Bulk feeders	0.55	0.55
Commercial areas	1.05–1.25	1.05–1.25

Source: Jones, A.I., Smith, B.E., and Ward, D.J., "Considerations for Higher Voltage Distribution," *IEEE Transactions on Power Delivery*, vol. 7, no. 2, pp. 782–8, April 1992.

space is hard to find and load growth is high. If the existing subtransmission voltage is 34.5 kV, then using that voltage for distribution is attractive; additional capacity can be met by adding customers to existing 34.5-kV lines (a neutral may need to be added to the 34.5-kV subtransmission line).

Higher voltage systems are also more prone to ferroresonance. Radio interference is also more common at higher voltages.

Overall, the 15-kV class voltages provide a good balance between cost, reliability, safety, and reach. Although a 15-kV circuit does not naturally provide long reach, with voltage regulators and feeder capacitors it can be stretched to reach 20 mi or more. That said, higher voltages have advantages, especially for rural lines and for high-load areas, particularly where substation space is expensive.

Many utilities have multiple voltages (as shown by the survey data in Figure 1.11). Even one circuit may have multiple voltages. For example, a utility may install a 12.47-kV circuit in an area presently served by 4.16 kV. Some of the circuit may be converted to 12.47 kV, but much of it can be left as is and coupled through 12.47/4.16-kV step-down transformer banks.

1.4 Distribution Substations

Distribution substations come in many sizes and configurations. A small rural substation may have a nominal rating of 5 MVA while an urban station may be over 200 MVA. Figure 1.12 through Figure 1.14 show examples of small, medium, and large substations. As much as possible, many utilities have standardized substation layouts, transformer sizes, relaying systems, and automation and SCADA (supervisory control and data acquisition) facilities. Most distribution substation bus configurations are simple with limited redundancy.

Transformers smaller than 10 MVA are normally protected with fuses, but fuses are also used for transformers to 20 or 30 MVA. Fuses are inexpensive and simple; they don't need control power and take up little space. Fuses are not particularly sensitive, especially for evolving internal faults. Larger transformers normally have relay protection that operates a circuit switcher

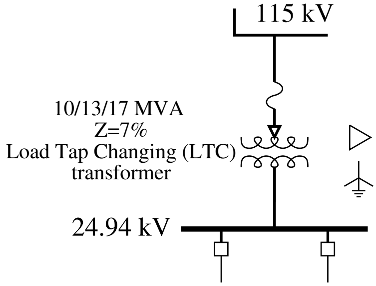

FIGURE 1.12
Example rural distribution substation.

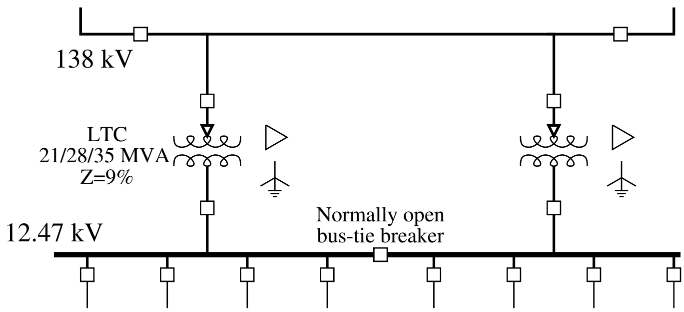

FIGURE 1.13
Example suburban distribution substation.

or a circuit breaker. Relays often include differential protection, sudden-pressure relays, and overcurrent relays. Both the differential protection and the sudden-pressure relays are sensitive enough to detect internal failures and clear the circuit to limit additional damage to the transformer. Occasionally, relays operate a high-side grounding switch instead of an interrupter. When the grounding switch engages, it creates a bolted fault that is cleared by an upstream device or devices.

The feeder interrupting devices are normally relayed circuit breakers, either free-standing units or metal-enclosed switchgear. Many utilities also use reclosers instead of breakers, especially at smaller substations.

Station transformers are normally protected by differential relays which trip if the current into the transformer is not very close to the current out of the transformer. Relaying may also include pressure sensors. The high-side protective device is often a circuit switcher but may also be fuses or a circuit breaker.

Two-bank stations are very common (Figure 1.13); these are the standard design for many utilities. Normally, utilities size the transformers so that if either transformer fails, the remaining unit can carry the entire substation's load. Utility practices vary on how much safety margin is built into this calculation, and load growth can eat into the redundancy.

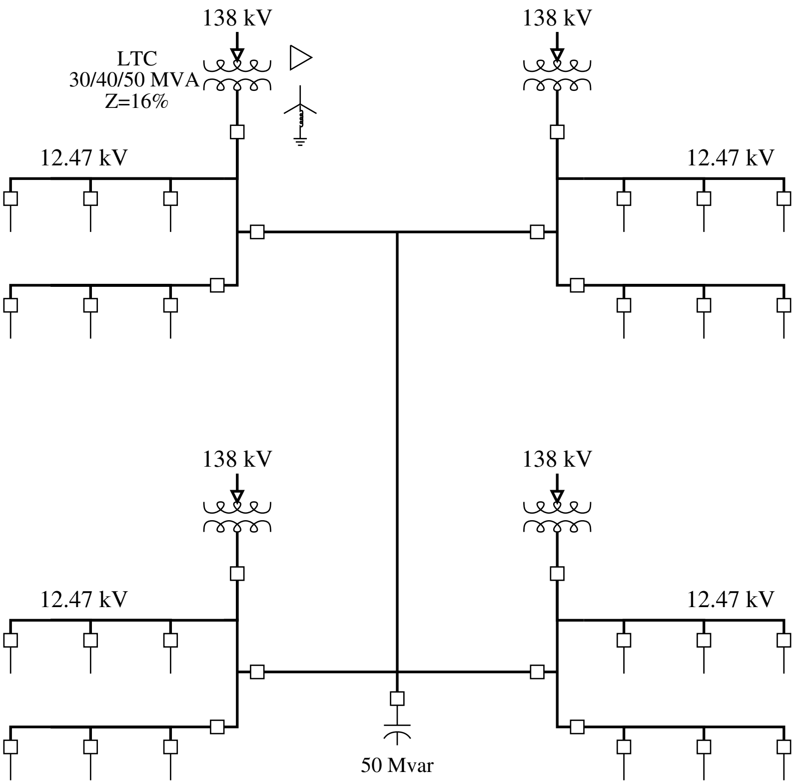

FIGURE 1.14
Example urban distribution substation.

Most utilities normally use a split bus: a bus tie between the two buses is normally left open in distribution substations. The advantages of a split bus are:

- *Lower fault current* — This is the main reason that bus ties are open. For a two-bank station with equal transformers, opening the bus tie cuts fault current in half.
- *Circulating current* — With a split bus, current cannot circulate through both transformers.
- *Bus regulation* — Bus voltage regulation is also simpler with a split bus. With the tie closed, control of paralleled tap changers is more difficult.

Having the bus tie closed has some advantages, and many utilities use closed ties under some circumstances. A closed bus tie is better for

- *Secondary networks* — When feeders from each bus supply either spot or grid secondary networks, closed bus ties help prevent circulating current through the secondary networks.

- *Unequal loading* — A closed bus tie helps balance the loading on the transformers. If the set of feeders on one bus has significantly different loading patterns (either seasonal or daily), then a closed bus tie helps even out the loading (and aging) of the two transformers.

Whether the bus tie is open or closed has little impact on reliability. In the uncommon event that one transformer fails, both designs allow the station to be reconfigured so that one transformer supplies both bus feeders. The closed-tie scenario is somewhat better in that an automated system can reconfigure the ties without total loss of voltage to customers (customers do see a very large voltage sag). In general, both designs perform about the same for voltage sags.

Urban substations are more likely to have more complicated bus arrangements. These could include ring buses or breaker-and-a-half schemes. Figure 1.14 shows an example of a large urban substation with feeders supplying secondary networks. If feeders are supplying secondary networks, it is not critical to maintain continuity to each feeder, but it is important to prevent loss of any one bus section or piece of equipment from shutting down the network (an *N*-1 design).

For more information on distribution substations, see (RUS 1724E-300, 2001; Westinghouse Electric Corporation, 1965).

1.5 Subtransmission Systems

Subtransmission systems are those circuits that supply distribution substations. Several different subtransmission systems can supply distribution substations. Common subtransmission voltages include 34.5, 69, 115, and 138 kV. Higher voltage subtransmission lines can carry more power with less losses over greater distances. Distribution circuits are occasionally supplied by high-voltage transmission lines such as 230 kV; such high voltages make for expensive high-side equipment in a substation. Subtransmission circuits are normally supplied by bulk transmission lines at subtransmission substations. For some utilities, one transmission system serves as both the subtransmission function (feeding distribution substations) and the transmission function (distributing power from bulk generators). There is much crossover in functionality and voltage. One utility may have a 23-kV subtransmission system supplying 4-kV distribution substations. Another utility right next door may have a 34.5-kV distribution system fed by a 138-kV subtransmission system. And within utilities, one can find a variety of different voltage combinations.

Of all of the subtransmission circuit arrangements, a radial configuration is the simplest and least expensive (see Figure 1.15). But radial circuits provide the most unreliable supply; a fault on the subtransmission circuit

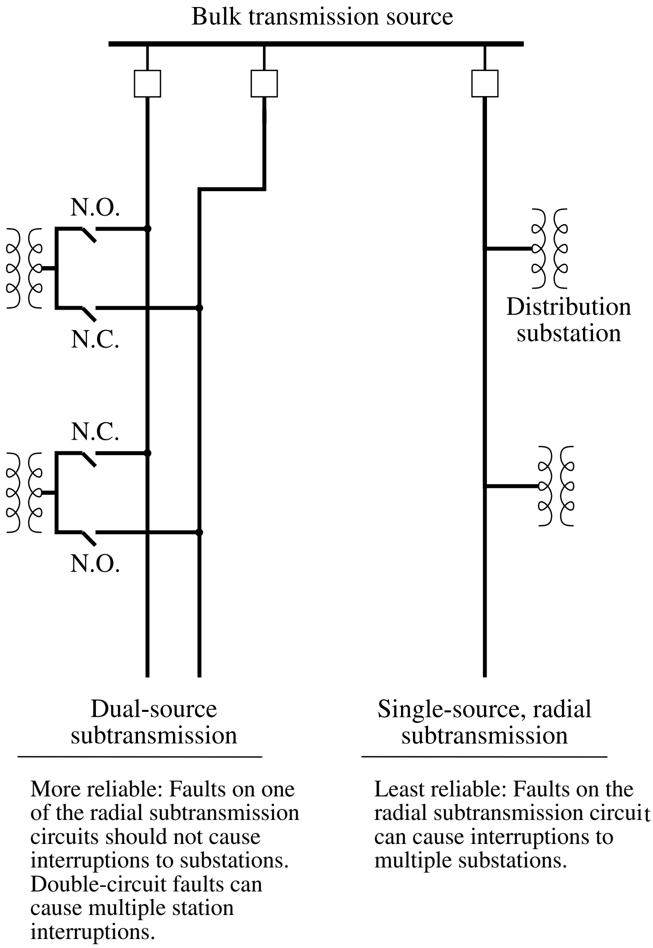

FIGURE 1.15
Radial subtransmission systems.

can force an interruption of several distribution substations and service to many customers. A variety of redundant subtransmission circuits are available, including dual circuits and looped or meshed circuits (see Figure 1.16). The design (and evolution) of subtransmission configurations depends on how the circuit developed, where the load is needed now and in the future, what the distribution circuit voltages are, where bulk transmission is available, where rights-of-way are available, and, of course, economic factors.

Most subtransmission circuits are overhead. Many are built right along roads and streets just like distribution lines. Some — especially higher voltage subtransmission circuits — use a private right-of-way such as bulk transmission lines use. Some new subtransmission lines are put underground, as development of solid-insulation cables has made costs more reasonable.

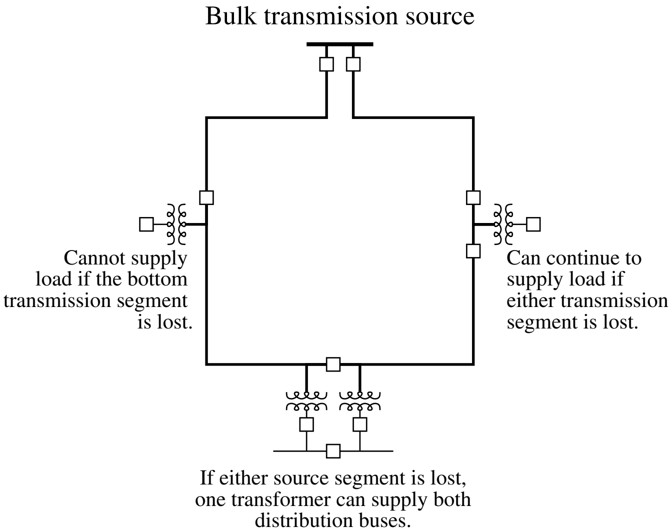

FIGURE 1.16
Looped subtransmission system.

Lower voltage subtransmission lines (69, 34.5, and 23 kV) tend to be designed and operated as are distribution lines, with radial or simple loop arrangements, using wood-pole construction along roads, with reclosers and regulators, often without a shield wire, and with time-overcurrent protection. Higher voltage transmission lines (115, 138, and 230 kV) tend to be designed and operated like bulk transmission lines, with loop or mesh arrangements, tower configurations on a private right-of-way, a shield wire or wires for lightning protection, and directional or pilot-wire relaying from two ends. Generators may or may not interface at the subtransmission level (which can affect protection practices).

1.6 Differences between European and North American Systems

Distribution systems around the world have evolved into different forms. The two main designs are North American and European. This book deals mainly with North American distribution practices; for more information on European systems, see Lakervi and Holmes (1995). For both forms, hardware is much the same: conductors, cables, insulators, arresters, regulators, and transformers are very similar. Both systems are radial, and voltages and power carrying capabilities are similar. The main differences are in layouts, configurations, and applications.

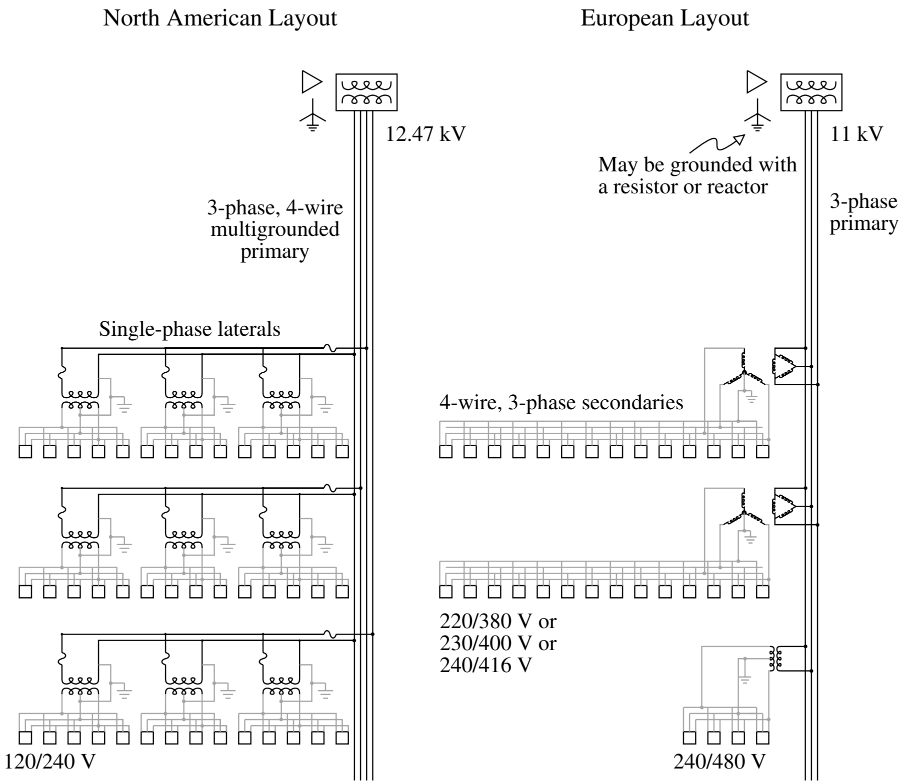

FIGURE 1.17
North American versus European distribution layouts.

Figure 1.17 compares the two systems. Relative to North American designs, European systems have larger transformers and more customers per transformer. Most European transformers are three-phase and on the order of 300 to 1000 kVA, much larger than typical North American 25- or 50-kVA single-phase units.

Secondary voltages have motivated many of the differences in distribution systems. North America has standardized on a 120/240-V secondary system; on these, voltage drop constrains how far utilities can run secondaries, typically no more than 250 ft. In European designs, higher secondary voltages allow secondaries to stretch to almost 1 mi. European secondaries are largely three-phase and most European countries have a standard secondary voltage of 220, 230, or 240 V, twice the North American standard. With twice the voltage, a circuit feeding the same load can reach four times the distance. And because three-phase secondaries can reach over twice the length of a single-phase secondary, overall, a European secondary can reach eight times the length of an American secondary for a given load and voltage drop. Although it is rare, some European utilities supply rural areas with single-phase taps made of two phases with single-phase transformers connected phase to phase.

In the European design, secondaries are used much like primary laterals in the North American design. In European designs, the primary is not tapped frequently, and primary-level fuses are not used as much. European utilities also do not use reclosing as religiously as North American utilities.

Some of the differences in designs center around the differences in loads and infrastructure. In Europe, the roads and buildings were already in place when the electrical system was developed, so the design had to "fit in." Secondary is often attached to buildings. In North America, many of the roads and electrical circuits were developed at the same time. Also, in Europe houses are packed together more and are smaller than houses in America.

Each type of system has its advantages. Some of the major differences between systems are the following (see also Carr and McCall, 1992; Meliopoulos et al., 1998; Nguyen et al., 2000):

- *Cost* — The European system is generally more expensive than the North American system, but there are so many variables that it is hard to compare them on a one-to-one basis. For the types of loads and layouts in Europe, the European system fits quite well. European primary equipment is generally more expensive, especially for areas that can be served by single-phase circuits.
- *Flexibility* — The North American system has a more flexible primary design, and the European system has a more flexible secondary design. For urban systems, the European system can take advantage of the flexible secondary; for example, transformers can be sited more conveniently. For rural systems and areas where load is spread out, the North American primary system is more flexible. The North American primary is slightly better suited for picking up new load and for circuit upgrades and extensions.
- *Safety* — The multigrounded neutral of the North American primary system provides many safety benefits; protection can more reliably clear faults, and the neutral acts as a physical barrier, as well as helping to prevent dangerous touch voltages during faults. The European system has the advantage that high-impedance faults are easier to detect.
- *Reliability* — Generally, North American designs result in fewer customer interruptions. Nguyen et al. (2000) simulated the performance of the two designs for a hypothetical area and found that the average frequency of interruptions was over 35% higher on the European system. Although European systems have less primary, almost all of it is on the main feeder backbone; loss of the main feeder results in an interruption for all customers on the circuit.

European systems need more switches and other gear to maintain the same level of reliability.

- *Power quality* — Generally, European systems have fewer voltage sags and momentary interruptions. On a European system, less primary exposure should translate into fewer momentary interruptions compared to a North American system that uses fuse saving. The three-wire European system helps protect against sags from line-to-ground faults. A squirrel across a bushing (from line to ground) causes a relatively high impedance fault path that does not sag the voltage much compared to a bolted fault on a well-grounded system. Even if a phase conductor faults to a low-impedance return path (such as a well-grounded secondary neutral), the delta – wye customer transformers provide better immunity to voltage sags, especially if the substation transformer is grounded through a resistor or reactor.
- *Aesthetics* — Having less primary, the European system has an aesthetic advantage: the secondary is easier to underground or to blend in. For underground systems, fewer transformer locations and longer secondary reach make siting easier.
- *Theft* — The flexibility of the European secondary system makes power much easier to steal. Developing countries especially have this problem. Secondaries are often strung along or on top of buildings; this easy access does not require great skill to attach into.

Outside of Europe and North America, both systems are used, and usage typically follows colonial patterns with European practices being more widely used. Some regions of the world have mixed distribution systems, using bits of North American and bits of European practices. The worst mixture is 120-V secondaries with European-style primaries; the low-voltage secondary has limited reach along with the more expensive European primary arrangement.

Higher secondary voltages have been explored (but not implemented to my knowledge) for North American systems to gain flexibility. Higher secondary voltages allow extensive use of secondary, which makes undergrounding easier and reduces costs. Westinghouse engineers contended that both 240/480-V three-wire single-phase and 265/460-V four-wire three-phase secondaries provide cost advantages over a similar 120/240-V three-wire secondary (Lawrence and Griscom, 1956; Lokay and Zimmerman, 1956). Higher secondary voltages do not force higher utilization voltages; a small transformer at each house converts 240 or 265 V to 120 V for lighting and standard outlet use (air conditioners and major appliances can be served directly without the extra transformation). More recently, Bergeron et al. (2000) outline a vision of a distribution system where primary-level distribution voltage is stepped down to an extensive 600-V, three-phase secondary system. At each house, an electronic transformer converts 600 V to 120/240 V.

1.7 Loads

Distribution systems obviously exist to supply electricity to end users, so loads and their characteristics are important. Utilities supply a broad range of loads, from rural areas with load densities of 10 kVA/mi^2 to urban areas with 300 MVA/mi^2. A utility may feed houses with a 10- to 20-kVA peak load on the same circuit as an industrial customer peaking at 5 MW. The electrical load on a feeder is the sum of all individual customer loads. And the electrical load of a customer is the sum of the load drawn by the customer's individual appliances. Customer loads have many common characteristics. Load levels vary through the day, peaking in the afternoon or early evening. Several definitions are used to quantify load characteristics at a given location on a circuit:

- *Demand* — The load average over a specified time period, often 15, 20, or 30 min. Demand can be used to characterize real power, reactive power, total power, or current. Peak demand over some period of time is the most common way utilities quantify a circuit's load. In substations, it is common to track the current demand.
- *Load factor* — The ratio of the average load over the peak load. Peak load is normally the maximum demand but may be the instantaneous peak. The load factor is between zero and one. A load factor close to 1.0 indicates that the load runs almost constantly. A low load factor indicates a more widely varying load. From the utility point of view, it is better to have high load-factor loads. Load factor is normally found from the total energy used (kilowatt-hours) as:

  $$LF = \frac{kWh}{d_{kW} \times h}$$

  where

  LF = load factor

  kWh = energy use in kilowatt-hours

  d_{kW} = peak demand in kilowatts

  h = number of hours during the time period
- *Coincident factor* — The ratio of the peak demand of a whole system to the sum of the individual peak demands within that system. The

peak demand of the whole system is referred to as the peak *diversified* demand or as the peak *coincident* demand. The individual peak demands are the *noncoincident* demands. The coincident factor is less than or equal to one. Normally, the coincident factor is much less than one because each of the individual loads do not hit their peak at the same time (they are not coincident).

- *Diversity factor* — The ratio of the sum of the individual peak demands in a system to the peak demand of the whole system. The diversity factor is greater than or equal to one and is the reciprocal of the coincident factor.
- *Responsibility factor* — The ratio of a load's demand at the time of the system peak to its peak demand. A load with a responsibility factor of one peaks at the same time as the overall system. The responsibility factor can be applied to individual customers, customer classes, or circuit sections.

The loads of certain customer classes tend to vary in similar patterns. Commercial loads are highest from 8 a.m. to 6 p.m. Residential loads peak in the evening. Weather significantly changes loading levels. On hot summer days, air conditioning increases the demand and reduces the diversity among loads. At the transformer level, load factors of 0.4 to 0.6 are typical (Gangel and Propst, 1965).

Several groups have evaluated coincidence factors as a function of the number of customers. Nickel and Braunstein (1981) determined that one curve fell roughly in the middle of several curves evaluated. Used by Arkansas Power and Light, this curve fits the following:

$$F_{co} = \frac{1}{2}\left(1 + \frac{5}{2n+3}\right)$$

where n is the number of customers (see Figure 1.18).

At the substation level, coincidence is also apparent. A transformer with four feeders, each peaking at 100 A, will peak at less than 400 A because of diversity between feeders. The coincident factor between four feeders is normally higher than coincident factors at the individual customer level. Expect coincident factors to be above 0.9. Each feeder is already highly diversified, so not much more is gained by grouping more customers together if the sets of customers are similar. If the customer mix on each feeder is different, then multiple feeders can have significant differences. If some feeders are mainly residential and others are commercial, the peak load of the feeders together can be significantly lower than the sum of the peaks. For distribution transformers, the peak responsibility factor ranges from 0.5 to 0.9 with 0.75 being typical (Nickel and Braunstein, 1981).

Different customer classes have different characteristics (see Figure 1.19 for an example). Residential loads peak more in the evening and have a

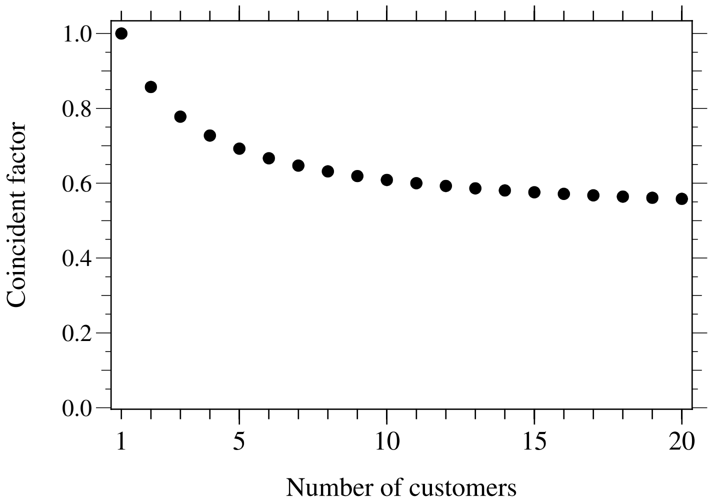

FIGURE 1.18
Coincident factor average curve for utilities.

relatively low load factor. Commercial loads tend to be more 8 a.m. to 6 p.m., and the industrial loads tend to run continuously and, as a class, they have a higher load factor.

1.8 The Past and the Future

Looking at Seelye's *Electrical Distribution Engineering* book (1930), we find more similarities to than differences from present-day distribution systems. The basic layout and operations of distribution infrastructure at the start of the 21st century are much the same as in the middle of the 20th century. Equipment has undergone steady improvements; transformers are more efficient; cables are much less expensive and easier to use; and protection equipment is better (see Figure 1.20 for some development milestones). Utilities operate more distribution circuits at higher voltages and use more underground circuits. But the concepts are much the same: ac, three-phase systems, radial circuits, fused laterals, overcurrent relays, etc. Advances in computer technology have opened up possibilities for more automation and more effective protection.

How will future distribution systems evolve? Given the fact that distribution systems of the year 2000 look much the same as distribution systems in 1950, a good guess is that the distribution system of 2050 (or at least 2025) will look much like today's systems. More and more of the electrical infrastructure will be placed underground. Designs and equipment will continue

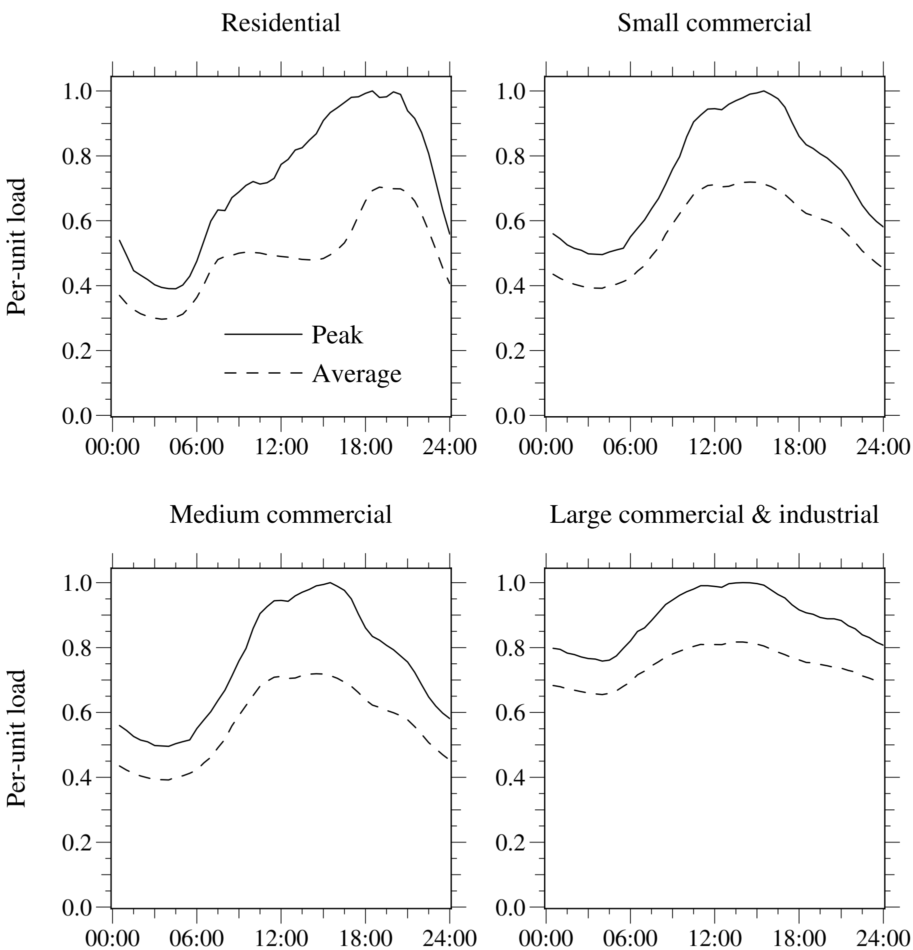

FIGURE 1.19
Daily load profiles for Pacific Gas and Electric (2002 data).

to be standardized. Gradually, the distribution system will evolve to take advantage of computer and communication gains: more automation, more communication between equipment, and smarter switches and controllers. EPRI outlined a vision of a future distribution system that was no longer radial, a distribution system that evolves to support widespread distributed generation and storage along with the ability to charge electric vehicles (EPRI TR-111683, 1998). Such a system needs directional relaying for reclosers, communication between devices, regulators with advanced controls, and information from and possibly control of distributed generators.

Advances in power electronics make more radical changes such as conversion to dc possible. Advances in power electronics allow flexible conversion between different frequencies, phasings, and voltages while still

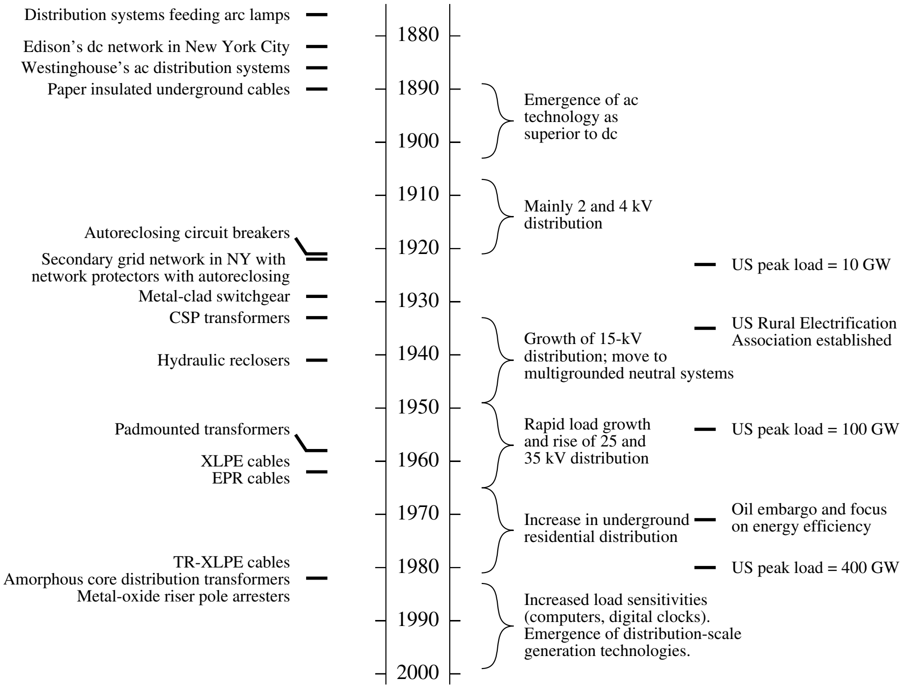

FIGURE 1.20
Electric power distribution development timeline.

producing ac voltage to the end user at the proper voltage. While possible, radical changes are unlikely, given the advantages to evolving an existing system rather than replacing it. Whatever the approach, the future has challenges; utilities will be expected to deliver more reliable power with minimal pollution while keeping the distribution system hidden from view and causing the least disruption possible. And of course, costs are expected to stay the same or go down.

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No matter how long you've been a Power Lineman, you still notice it when people refer to your poles as "telephone poles."

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