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Technical Comparison of North American and International Distribution Systems

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ABSTRACT

One might think that the electric distribution systems around the world have converged into very similar designs, with different end-use voltages and different plugs. In fact, the distribution systems around the world have converged into two main designs: North American and European. For both systems, the cable, conductors, insulators, arrestors, transformers, and other devices are very similar. What is quite different is the operational design, configurations, system protection, and fault detection. The key differences and similarities will be highlighted in this document.

Keywords
Automation
Delta connections
Distribution design
Fault detection
Impedance grounding
Peterson coil

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1
EUROPEAN AND NORTH AMERICAN DISTRIBUTION SYSTEMS

Overview

One might think that the electric distribution systems around the world have converged into very similar designs, with different end use voltages and different plugs! In fact, the distribution systems around the world have converged into two main designs: North American and European. For both systems, the cable, conductors, insulators, arrestors, transformers and other devices are very similar. What is quite different is the operational design, configurations, system protection, and fault detection. The purpose of this technical update is to provide a side-by-side comparison of key aspects of the distribution system, noting similarities and differences.

The European Power Delivery System

For initial discussion purposes, Figure 1-2 provides a broad overview of the European MV system from the HV substation through the MV/LV substations.

Primary (HV/MV) Substation

A typical HV to MV substation design is illustrated in Figure 1-1. The HV/MV substation accepts power from multiple HV lines through HV circuit breakers (CB's) connected to the HV Bus. A normally-closed disconnect switch on the HV bus allows power from the transmission system to flow into and out the substation. Circuit breakers, connected between the HV Bus and the substation transformers protect the HV bus should a transformer fault occur. Load Tap Changers (LTC's) are integral to the substation transformers to provide 3-phase voltage regulation to the MV Bus.



Figure 1-1
Example of European HV/MV Substation

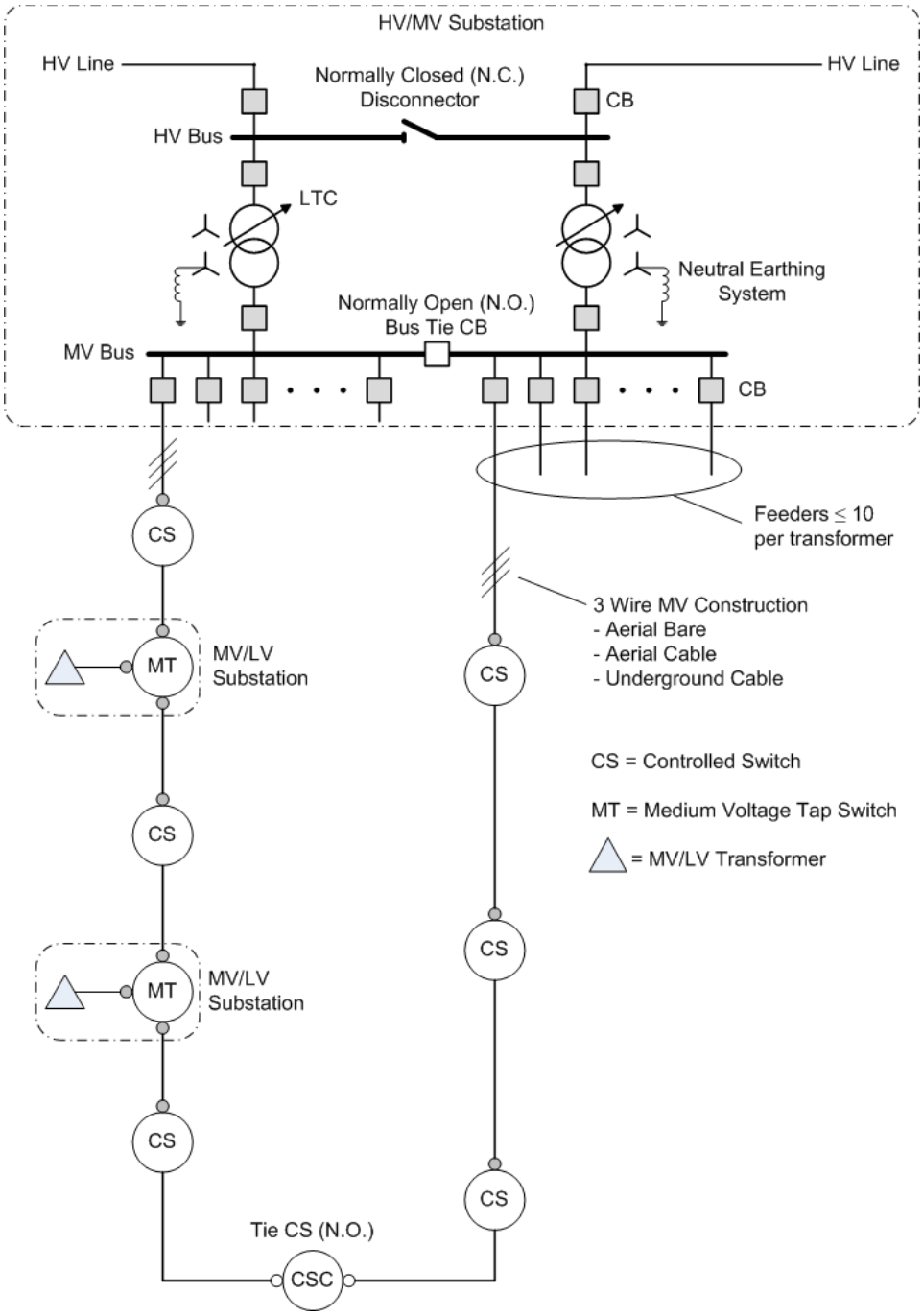


Figure 1-2
Typical European Power Delivery Overview

The power transformers shown in Figure 1-2 are connected Y-Y (alternately Δ-Y) with the MV neutral point connected to the Neutral Earthing System. In compensated distribution networks the system is grounded through a variable impedance reactor connected to the power transformer secondary neutral or the neutral of a grounding bank. This reactor compensates the system phase-to-ground capacitance such that the zero-sequence network becomes a very high impedance path. The reactor, known as the ***Petersen Coil***, permits adjustment of the inductance value to preserve the tuning condition of the system for different network topologies. Petersen

Coil compensation enables low ground-fault currents on the MV system that are likely self-extinguishing without a breaker operation.

This is a common practice throughout many countries in Europe with some variations on the specifics of the design and fault detection approaches. Compensated grounding provides self-extinction of the fault arc in overhead lines for about 80% of temporary ground faults. Considering that about 80% of ground faults are temporary, one can conclude that more than 60% of overhead line ground faults clear without breaker tripping. [1] In areas of Europe where neutral compensation is not used, either the system is operated as ungrounded (Isolated Earthing) or the MV system is high-resistance grounded (earthed).



Figure 1-3
Typical Petersen Coil Installation

MV Distribution

Referring back to Figure 1-2, the medium voltage system starts at the HV/MV substation MV bus (MV Distribution Bus). The MV distribution bus is the supply point for up to ten MV feeder circuit breakers per bus. These circuit breakers protect the MV feeder's distribution power to industry and general population base. The MV feeders are three-wire systems constructed for

overhead (OH) and/or underground (UG) distribution. The OH conductors may be made up of three bare conductors supported from poles via insulators or the OH conductors may be contained into a single aerial cable assembly that is attached to the poles above ground without the need for insulators.

For underground MV feeder installation, the three conductors are constructed and contained in a single underground cable that may be directly buried or placed into a conduit system. The MV feeder interconnects controlled switches (CS's) and MV tap (MT) equipment to supply power to MV/LV distribution substations.

Generally, a MV feeder terminates at a normally open CS (CSC) that connects it to an adjacent feeder. The switches may be remotely controlled, and if equipped with Fault Passage Indicators, can be coordinated with the feeder CB to automatically isolate a section of the feeder. The controlled switches are similar to sectionalizers used by many U.S. utilities. Like the sectionalizers, the CS's have load-break capability but are not designed to open when fault current is present. When automated, the CS's coordinate with the feeder CB to open when the feeder CB has sensed a fault and opened during the interruption phase of a reclose cycle. Consequently, the CS open's automatically only when there is no line voltage applied to the CS. The circular symbols containing the letters "MT" in Figure 2 represent medium voltage tap equipment used to provide one or more taps from the feeder. Figure 4 provides a detailed diagram of a basic three-port MT that provides a feeder source switch, a feeder load switch and a MV tap switch.

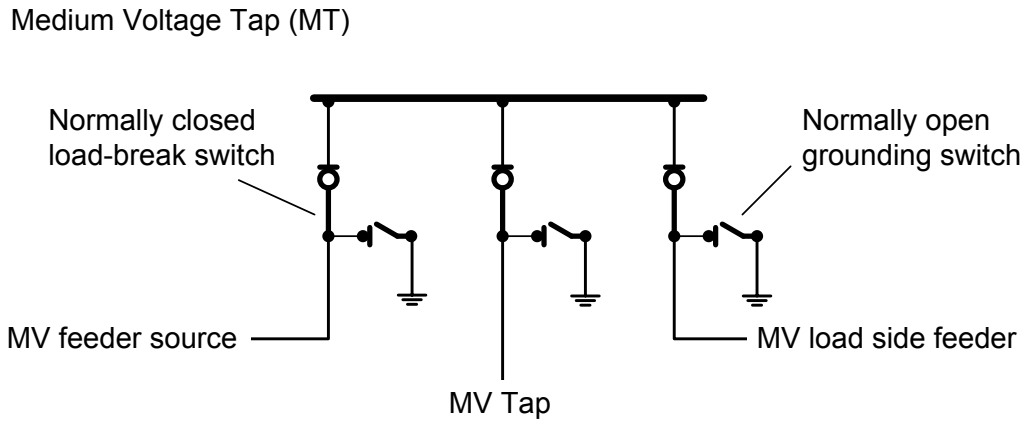


Figure 1-4
Medium Voltage Tap

The MV feeder source and load switches provide a thru-feed for power to the end of the feeder. Figure 4 shows only one MV tap switch to supply power to a lateral or lobe. Additional, MV tap switches may be added to support power distribution needs.

Secondary (MV/LV) Substation

Working through the picture from left to right the Medium voltage tap (MT) on the left provides fused protection to the HV terminals (connected by orange cables) of the transformer in the middle. Light gray conductors from the transformer LV terminals feed the LV circuit breakers located on the right-hand wall. In this picture the darker gray conductors connected to the load side of the LV CBs serve the low voltage distribution system outside the substation.



Figure 1-5
Exterior Views of a Typical European Secondary (MV/LV) Substations



Figure 1-6
Interior Views of Typical European Secondary (MV/LV) Substations

While Figure 1-6 provides and understanding of equipment size and placement, the one-line drawing in Figure 1-7 provides and understanding of how the equipment is electrically connected. The three-phase distribution transformers are typically rated between 250 kVA and 1000 kVA.

Figure 1-8 shows only one MV fused tap for the one three-phase transformer. While the LV CBs shown in Figure 1-8 are shown connected to a common bus, each CB is supplied power via a dedicated set of four conductors connected to the transformer LV terminals. Alternately, the LV may be protected by fuses instead of circuit breakers.

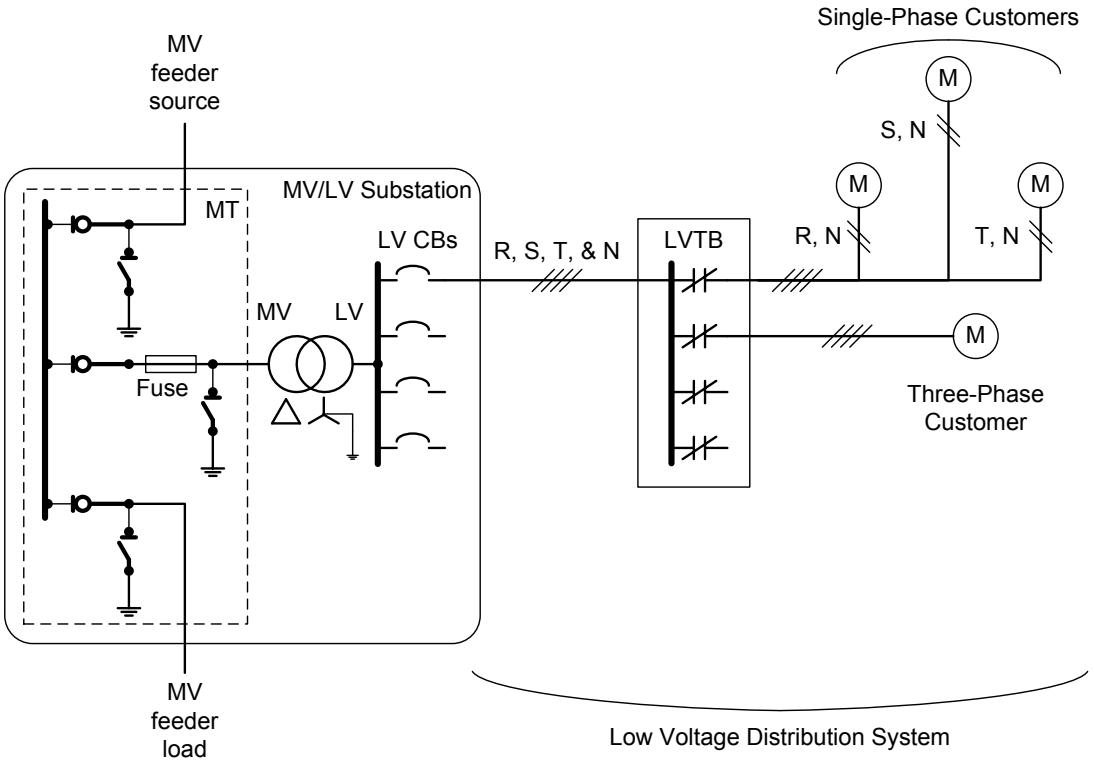


Figure 1-7
Secondary (MV/LV) Substation and LV Distribution One-Line

LV Distribution

The right side of Figure 1-7 illustrates the basic layout of a European low voltage distribution system (LVDS). The LVDS starts with four-pole low voltage circuit breakers (or alternately fuses) in the MV/LV substation. The LV circuit breakers or fuses supply power to the Low Voltage Terminal Box (LVTB) where the power is further divided into branches that ultimately feed individual electronic revenue meters.



Figure 1-8
Examples of Low Voltage Circuit Breakers/Fuse Panels

Another view of the European secondary is provided in the figure below. Here we see the typical Δ-Y distribution transformer which feeds a combination of three phase customers and single phase customers connected Ø-Ø. Also shown is a typical rural single Ø transformer which is again connected Ø-Ø providing a nominal 230V.

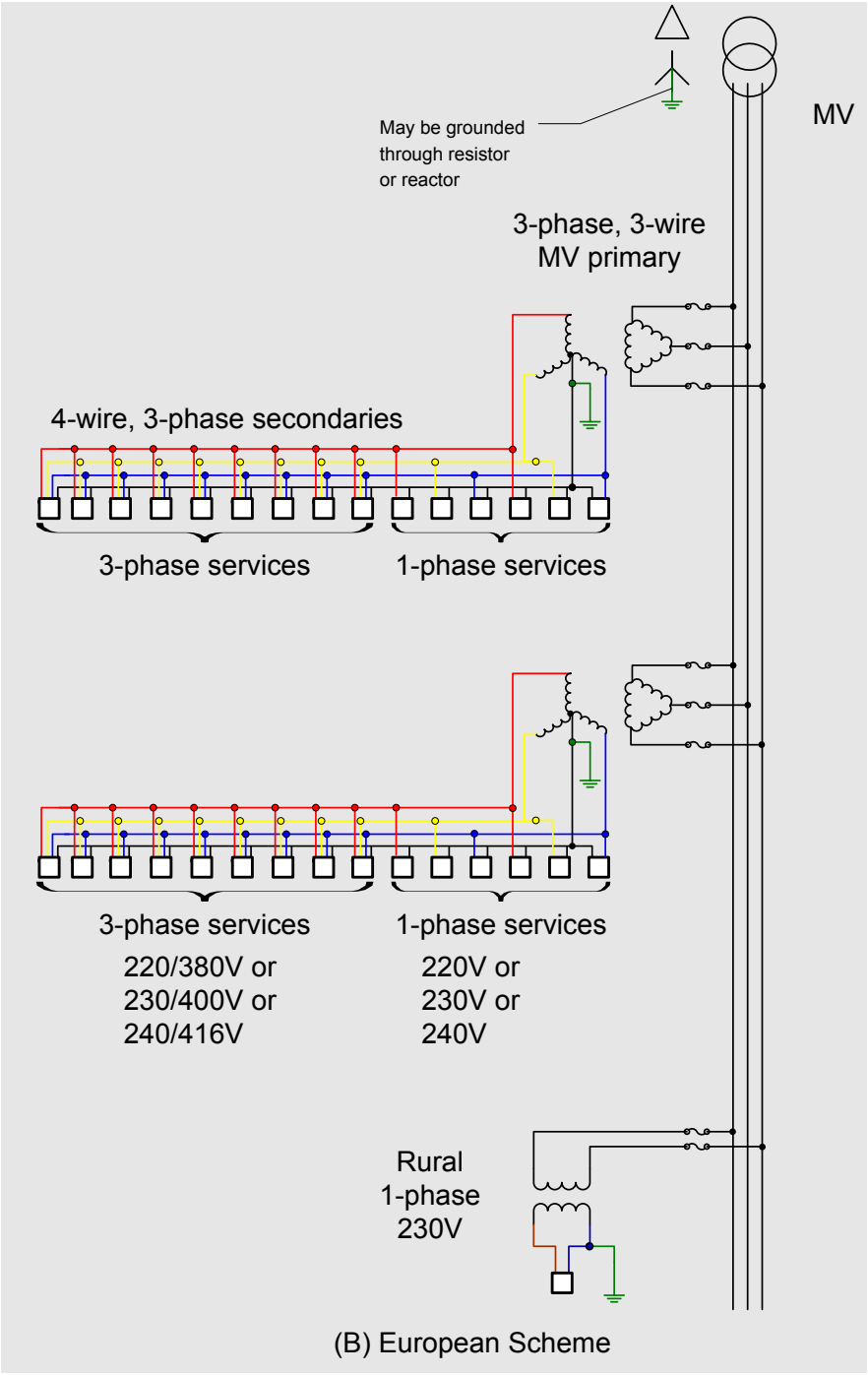


Figure 1-9
European Secondary Configurations [2]

Operating at higher secondary voltages, allows European secondary circuits to stretch for more than a kilometer. European secondary circuits are mostly 3Ø as opposed to North American secondary circuits which are mostly 1Ø. European secondary circuits operate at 220 volts Ø-N, nearly twice the North American standard. The combination of these two factors enable European secondary circuits to run these much longer distances. [2]

In fact, European secondary circuits are designed and operated similar to primary (MV) laterals in North America. The similarities are that European secondary circuits and North American primary laterals are highly branched, have one or more level of fusing or sectionalizing, and run wherever the load needs to be served.

The European primary circuits are designed and operated similar to subtransmission circuits in North America. The European primary (MV) circuits are not tapped. In fact, they typically run from the primary substation breaker to Secondary Substation and then to the next Secondary Substation, and so on. This is similar to North American subtransmission circuits which run from the primary substation breaker to a Distribution Substation to the next Distribution Substation, and so on.

The North American Power Delivery System

North American distribution feeders come in many different configurations and circuit lengths, but most share many common characteristics. Figure 1-10 provides a broad overview of a typical North American MV system from the HV/MV substation through distribution transformers serving individual LV customers or groups of customers.

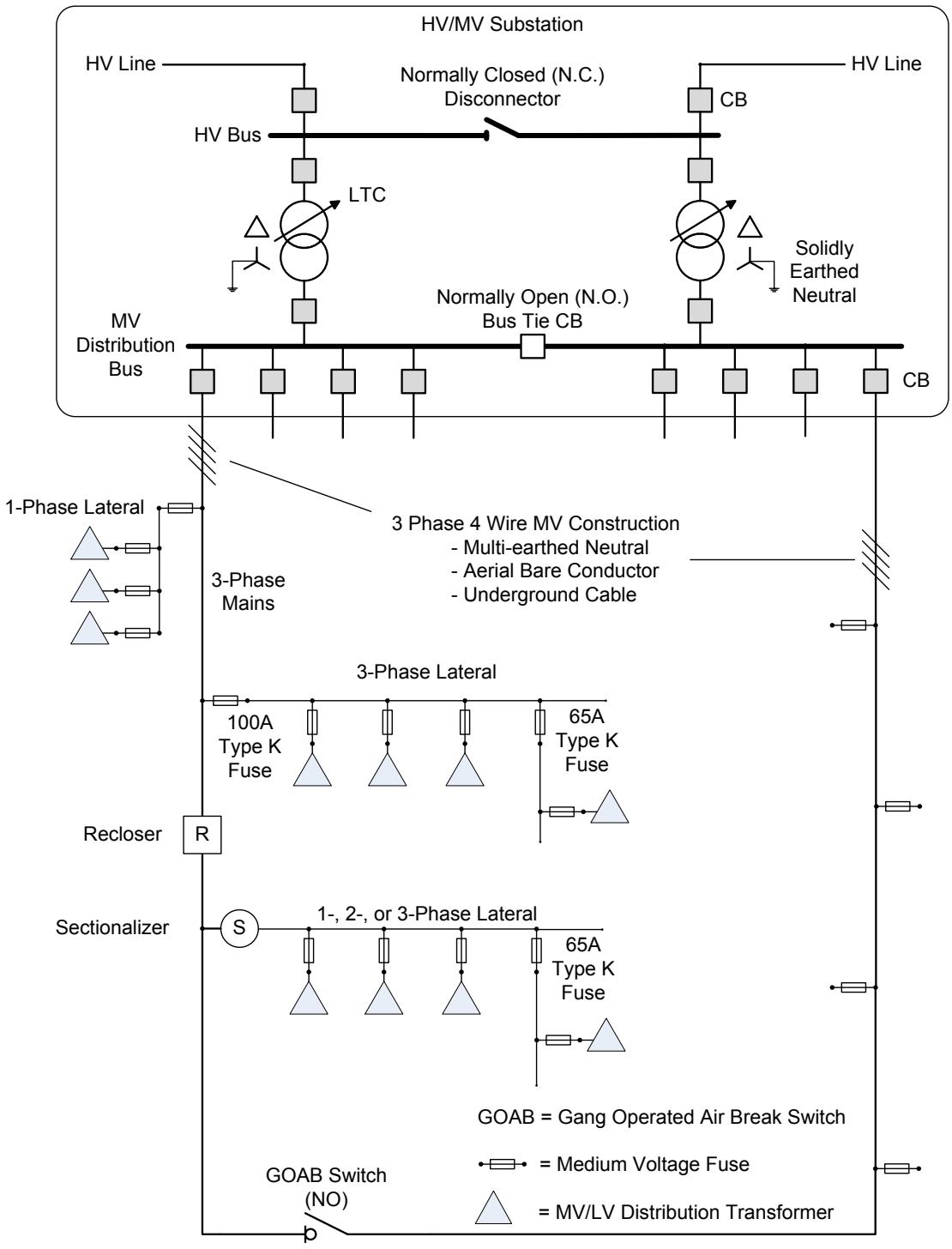


Figure 1-10
North American Power Delivery System Overview

HV/MV Substation

A typical HV to MV substation, illustrated at the top of Figure 1-10, accepts power from multiple HV lines through HV circuit breakers (CB's) connected to the HV Bus. A normally-closed disconnect switch on the HV bus allows power from the transmission system to flow into and out the substation. CB's, connected between the HV Bus and the substation transformers protect the HV bus should a transformer fault occur. Load Tap Changers (LTC or OLTC) are integral to the substation transformers to provide 3-phase voltage regulation to the MV Bus.



Figure 1-11
Photo of Typical North American HV/MV Substation

Depending on system requirements the HV/MV transformers may be connected Wye:Wye or Delta:Wye. However, a high percentage of these transformers are connected Delta:Wye with the MV neutral point solidly connected to Earth. While the compensated neutral earthing system (Petersen coil) has been applied in the past, there are few, if any, applications remaining in operation in the United States. If these applications are used, they typically will be found on sub-transmission systems where there are no single-phase loads. While it is common practice to establish HV/MV substation transformers as pairs in urban areas, rural areas may only have one power transformer serving a substation. These rural substations may be supplied by subtransmission feeders (typically 35kV – 69kV range) instead of transmission feeders.

MV Distribution

The typical North American MV distribution voltage classes are 5, 15, 25, or 35 kV. The 15-kV class voltage level is the most popular, comprising more than 80% of all distribution circuits within the U.S. Within the 15-kV class, the nominal voltages of 12.47, 13.2, and 13.8 kV are the most popular distribution primary voltages. These circuits typically have main feeders of from 5 to 25 km in length with various three-phase and single-phase branches (laterals) from the three-phase main line. The loading of such circuits varies greatly; however, under typical operating conditions, 4 to 6 MVA is representative of the peak loads on most 15-kV class feeders. Feeders at 25- and 35-kV voltage levels carry correspondingly higher loads of 7 to 10 MVA and 10 to 16 MVA, respectively. These would represent typical loading, but the maximum capacity of these circuits is somewhat higher depending on conductor size and circuit length.

In Figure 1-10 the MV system starts at the HV/MV Substation, MV bus (MV Distribution Bus). The MV distribution bus is the supply point for typically two to six MV feeder circuit breakers (CB's) per bus. The actual number is dependent upon transformer capacity and local distribution requirements. These CB's protect the MV feeder's distribution power to industry and general population base. The MV feeders, both overhead (OH) and underground (UG), are typically constructed as four-wire multigrounded-neutral distribution systems. The OH lines are typically constructed of four bare conductors. The three phase conductors are supported from poles by insulators with appropriate BIL. The multigrounded neutral design permits the use of reduced-BIL insulators.

The fourth conductor is the neutral and is typically attached to the pole below the three phase conductors. The neutral conductor is bonded to earth at every opportunity, especially where OH equipment is located. On line sections with other OH equipment, the neutral is commonly bonded to ground at least every 2nd or 3rd pole. Solidly-grounded and low-impedance grounded systems have high levels of ground fault currents that require de-energizing the line with a fault-current interrupting device such as a breaker, recloser, or fuse to remove the fault from the system. Ground overcurrent and directional overcurrent relays are the typical ground fault protection solution. However, high-impedance ground fault detection is difficult in four-wire multigrounded neutral systems because the ground fault current is combined with the unbalanced, or residual, load current from loads connected between phase and neutral. [3]

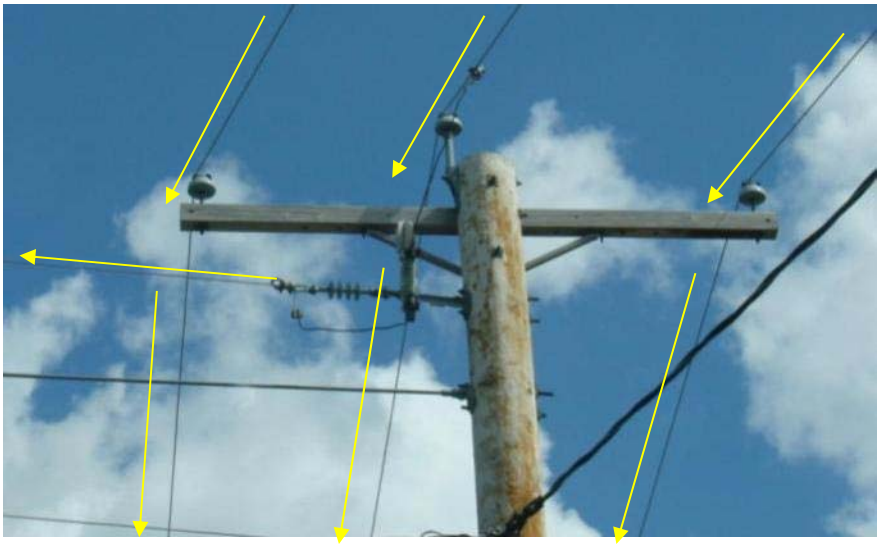


Figure 1-12
Three Phase Mains - Transition to Single Phase Tap

The typical North American MV distribution system is operated as a radial system, where MV feeders typically terminate at a normally open tie switch that may be used to provide power from an alternate feeder. The tie switch may be made up of three individual switches that require a long fiberglass pole with proper voltage rating to close or open each switch. All three phases may be switched through a gang-operated air break (GOAB) switch located on an overhead structure. Note that in all MV switch scenarios the neutral is never switched so that it is always connected to the alternate feeder neutral. North American distribution feeders, particularly those in suburban and rural areas, tend to be long, with many taps and laterals. As shown in

Figure 1-12, the feeders originate from the substation as three phase circuits, but may tap off the three-phase mainline with only 2 phases or 1 phase (and the neutral). This configuration enables the feeders to serve single phase loads while economizing on the number of conductors required.

To safely and reliably operate this sort of complex distribution system, North American utilities install many protective devices and switching devices on the overhead and underground distribution feeders. Note that the entire class of secondary meshed (network) feeders will not be discussed in this overview of North American systems. Network systems are commonly used in urban areas but, even in these locations, there is a trend towards the design of primary looped feeders instead of secondary networks.

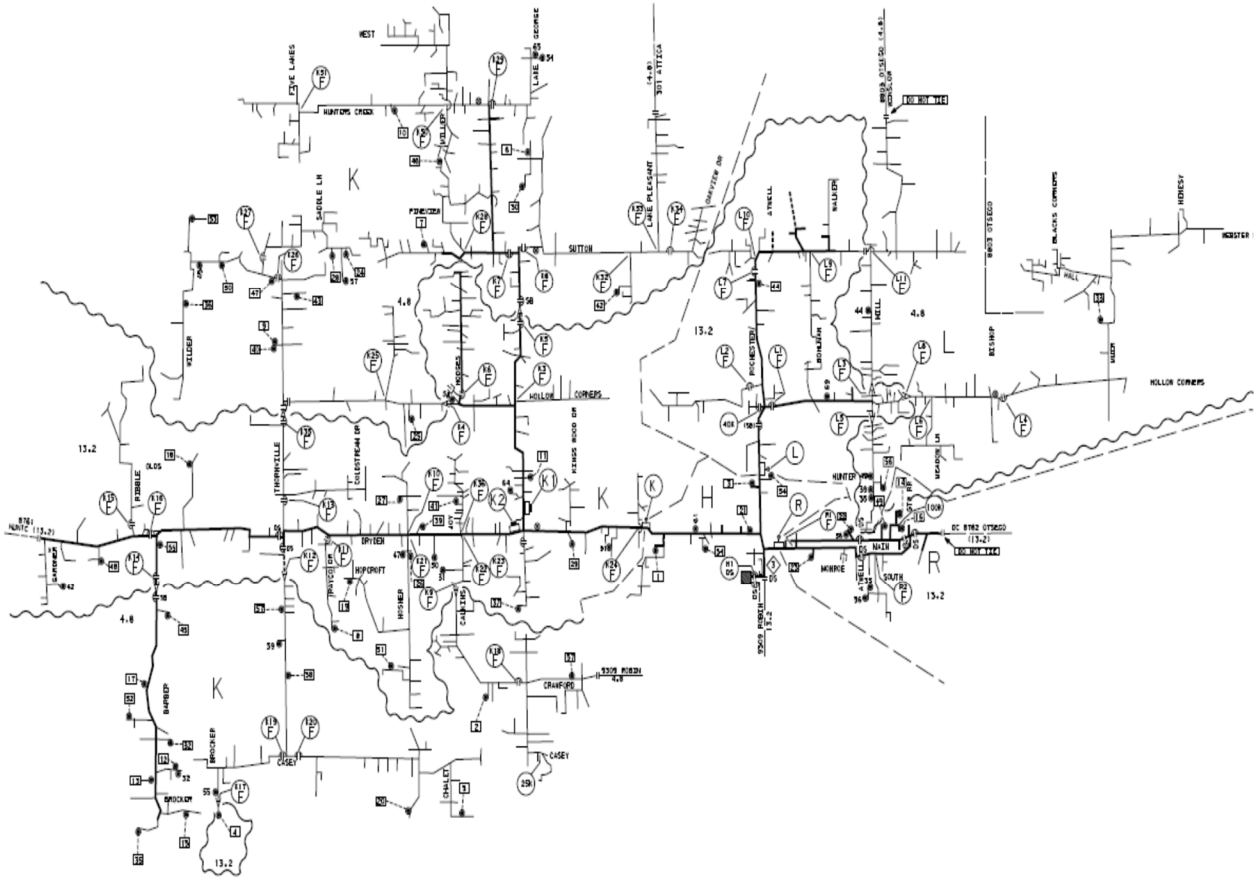


Figure 1-13
Typical Rural North American MV Feeder

Overhead Feeders

Overhead MV feeders often contain a variety of switchgear including Reclosers, Sectionalizers, Automated Switches, Group Operated Switches, Single-Phase Disconnect Switches, and Fuses.

Reclosers

Reclosers (Figure 1-13) are essentially smaller, lighter, self-contained circuit breakers that are installed on the distribution system. Like breakers, they are designed to interrupt both load and fault current. As the name indicates, they also are designed to automatically "reclose" after interrupting the fault current to attempt immediate restoration of power to the load. This takes advantage of the fact that approximately 80% of faults on the overhead system are temporary and will clear after the current is interrupting. Reclosers were historically developed to be deployed on rural feeders to extend the protective reach beyond the zone of protection of the feeder circuit breaker. They have also been historically deployed as a reliability enhancement to isolate feeder sections having high fault exposure from the rest of the feeder mains. Today, reclosers are often deployed as the primary switching devices of many Distribution Automation (DA) programs because the reclosers can automatically sense the fault current and trip to clear the fault. This provides the benefit that customers upstream of the recloser are prevented from experiencing a momentary outage without requiring the intervention of the DA system. Downstream reclosers may be set to sense the loss of potential in the absence of fault current and open automatically to isolate the fault. Reclosers typically will be installed with an Intelligent Electronic Device (IED) Controller to enable protection settings, control settings and integration with a remote terminal unit or communications interface.



Figure 1-14
Typical North American Overhead Three Phase Recloser and IED Controller

A new type of reclosing devices has been developed by S&C Electric Co. which they call the IntelliRupter® PulseCloser. This device provides functionality similar to a recloser in that the device trips to isolate fault current and closes back into the circuit to test if the line has a permanent or temporary fault. The key difference is that the PulseCloser technology has a tightly-controlled vacuum breaker technology that can test the line with a brief pulse to limit the amount of energy supplied to the fault. If the fault is still present, the device will ultimately lock out.



Figure 1-15
PulseCloser (Courtesy of S&C Electric)

Sectionalizers

Sectionalizers (Figure 1-15) may have similar appearance to a recloser, and come with similar sensing and control mechanisms, but the functionality is different. Sectionalizers can interrupt load current, but cannot interrupt fault current. Instead, they count the reclosing shots on the circuit from an upstream protective device, and after a configurable number of counts will open while the circuit is de-energized. Sectionalizers are often deployed where coordination is difficult to achieve between the substation circuit breaker or recloser and downstream fusing. If sectionalizers are deployed as the distribution automation device, the feeder circuit breaker will sense the fault current and trip to clear the fault. During the reclose interval of the circuit breaker, sectionalizers will sense the loss of potential and open automatically to isolate the fault. Downstream sectionalizers can be operated to open and isolate the fault between automated switching devices, putting the feeder in a position to enable remote restoration. Sectionalizers typically will be installed with an Intelligent Electronic Device (IED) Controller to enable protection settings, control settings, and integration with a remote terminal unit or communications interface.



Figure 1-16
Installed OH Sectionalizer

Switches

Switches come in various forms: automated, motor operated, gang operated, and single-phase stick operated. Automated switches provide three-phase operation of a vacuum, air, oil or SF_6-insulated MV switch. These switches may be equipped with internal sensing, and typically come with an Intelligent Electronics Device (IED) controller.



Figure 1-17
Typical North American Automated Switch

Motor-Operated Disconnect Switches add a motor mechanism to remotely operate a set of gang-operated switches. Typically, gang-operated disconnect switches are switched by a field technician operating a mechanism at the base of the pole, via a mechanical linkage to the switch at the top of the pole. The motor operator takes the place of that mechanical linkage and enables integration with a remote terminal unit to provide remote control.



Figure 1-18
Typical Overhead Gang Operated Disconnect Switch and Ground Level Control Handle

Lateral Fuses

Branches or taps off the main feeder are often called laterals. It is common practice to install fuses between the main feeder and the lateral to isolate the lateral should a permanent fault occur on the lateral. Line fuses are also used where equipment is connected to the feeder or lateral. Ideally, a properly coordinated circuit is one where the fuses are selected to allow the fuse nearest the fault to open (blow) before the other source side fuse(s) blow. The "3-phase Lateral" shown in the middle Figure 1-10 is fused on the source side with a 100-A fuse while a 65-A fuse provides lateral protection on the fare right end of the 3-phase lateral. A fault on the load side of the 65-A fuse should cause the 65-A fuse to blow before the 100-A fuse blows. Similarly, a fault on the lateral between the 100-A fuse and the 65-A fuse should cause the 100-A fuse to blow before the feeder circuit breaker operates at the substation.



Figure 1-19
Typical North American OH Fuses

North American overhead feeders typically serve residential and small commercial customers via single-phase transformers installed between the MV phase and the neutral Three-phase customers are often supplied by a bank of three single-phase transformers wired together externally as shown in Figure 1-19.



Figure 1-20
Single Phase and Three Phase Overhead Transformer Installations

Underground Feeders

North American dedicated underground feeder designs utilize padmount switchgear, which can feature both switching and fusing options, in various combinations. A number of small transformers are typically supplied by the fused legs of the switchgear, as shown in Figure 1-20. The switchgear comes in a number of configurations with varying numbers of 600-A three-phase switched legs and 200-A three-phase fused legs. The diagram below is a simplified single-line diagram, demonstrating a system of two U.S. underground feeders emanating from substation circuit breakers on the left and the right, feeding a system of switchgear, which in turn supply systems of transformers. The switchgear and transformers may be installed on concrete or fiberglass pads above ground, in subsurface vaults, or in building vaults.

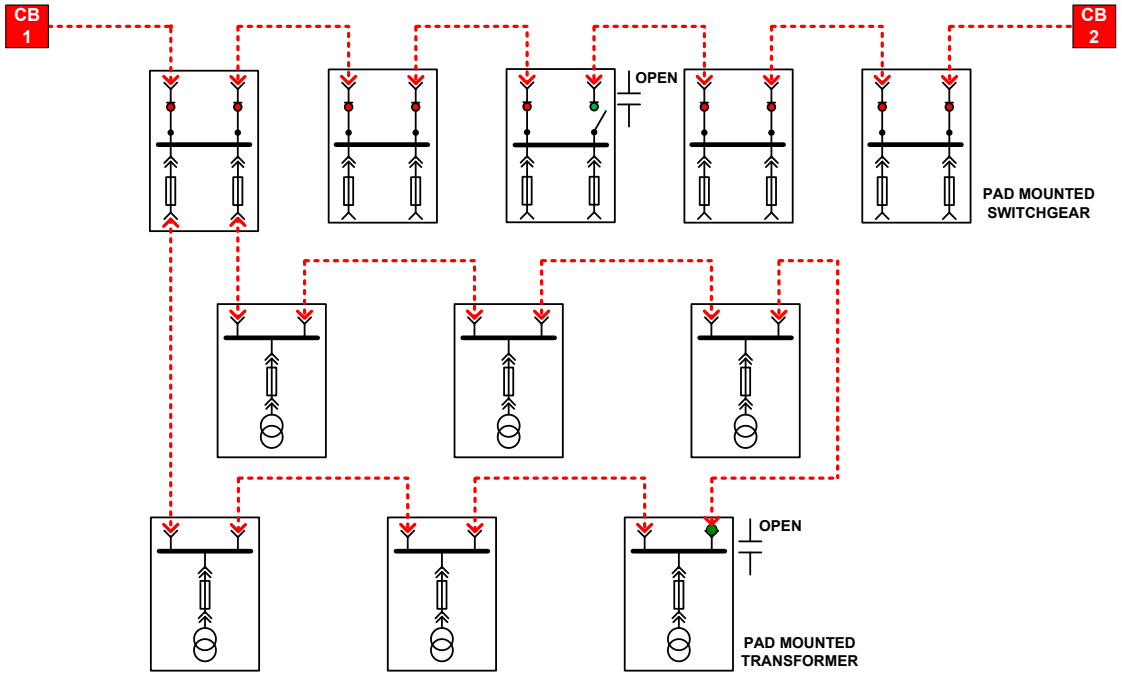


Figure 1-21
Typical U.S. Underground Feeder

The main three-phase backbone of each feeder passes through switchgear with two 600-A switches on the main line and two fuses (typically rated 200 A) feeding distribution transformers. One of the fused underground residential distribution (URD) loops is included in Figure 1-33, showing how the padmount transformers are supplied from two switchgear cabinets with an open point (accomplished by a parked cable elbow) in the middle of the loop. This allows for relatively fast manual restoration. Faulted Circuit Interrupters (FCIs) triggering on over-current are typically installed at each of the 600-A switches on the pad-mounted switchgear and on each transformer on the 200-A URD loop to enable timely fault location and restoration switching.

The photos below show a typical North American padmount switchgear and padmount transformer. Components necessary to enable automation of switchgear (motor operators, controllers and RTUs) are installed on cabinets attached to the side of the switchgear.



Figure 1-22
Typical North American Switchgear (Pad Mounted)



Figure 1-23
Typical Switchgear Control Cabinet

Each switchgear will serve a three-phase loop of 5-20 single phase transformers feeding a residential or commercial area. In rural and suburban residential areas, the transformers are typically in the range of 25kVA to 100kVA, depending on the density of the load served, each serving 5-15 customers. The primary circuit feeder cable serving each transformer will typically have a faulted circuit indicator (FCI) device installed which triggers on overcurrent to provide field crews with information necessary to diagnose the location of a faulted cable to a particular section between two adjacent transformers.



Figure 1-24
Typical North American Single Phase Pad Mounted Transformer (Opened and Closed)



Figure 1-25
Typical North American Three Phase Pad Mounted Distribution Transformer

Station and Feeder Characteristics	Most Common Value	Other Common Values
Voltage	12.47 kV	4.16,4.8,13.2, 13.8, 24.94, 34.5 kV
Substation transformer quantity	2	1 - 6
Substation transformer capacity	21 MVA	5 – 60 MVA
Number of feeders per bus	4	1-8
Feeder peak load current	400 A	100 – 600 A
Number of customers on feeder	800	50 - 5000
Length of feeder mains	6.5 kilometers	3 – 24 kilometers
Length of feeder including laterals	13 km	6 – 40 kilometers
Feeder mains conductor size	350 kcmil	4/0 to 795 kcmil
Laterals conductor size	#2	#6 to 2/0
Laterals peak load current	25A	5 – 50A
Lateral length	0.8 kilometers	0.3 to 8 kilometers
Distribution transformer sized (1ph)	25 kVA	10 to 75 kVA

Table 1-1
Typical North American Feeder Characteristics

LV Distribution

For most customers, the "primary" or medium voltage (MV) is stepped down with distribution, or service, transformers to the "secondary" or low-voltage (LV) level for delivery of power to customer loads on the system. Low voltage is defined in the ANSI/IEEE standards as less than 600 volts. Common secondary voltages for three-phase, Wye-grounded services are 480Y/277 volts or 208Y/120 volts. The first number identifies the phase-to-phase voltage and the second identifies the phase-to-neutral voltage. Phase-to-neutral voltage is related to the phase-to-phase voltage by the square root of three if the voltages are balanced. Most commercial building are served at two three-phase voltages: 480 V and 208 V. For single-phase service, which serves most residential customers, 240/120 volts is the most common service voltage. The 240-volt secondary winding is split into two 120-volt "legs" which provide two 120-volt services as well as 240-V service to the residential customers as shown in Figure 1-25.

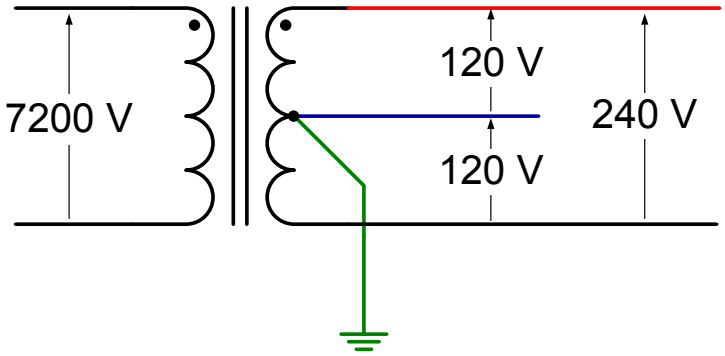


Figure 1-26
Typical North American Distribution Transformer Connection

LV systems in North America are much less complex than those in Europe, specifically because each LV circuit typically only supplies 5-10 customers, while there may be 70-100 customers on a 400 V LV circuit in Europe. North American LV systems may be in a STAR configuration (some overhead and all underground systems) or a BUSSED configuration (overhead only). A STAR configured LV is one where an individual LV circuit is connected between the transformer and each individual customer.



Figure 1-27
Configuration Overhead LV System (All Triplex Taps to Customers Emanate from the Transformer Pole)



Figure 1-28
Bussed Configuration Overhead LV System (Open Wire Bus Going Left and Right with Triplex Tap to Customer)

Similarities/Difference in North American and European Distribution

While the general distribution system objectives of reliability, safety, efficiency, and economic operation are the same worldwide, the specific designs and operations to achieve these objectives are obviously different in different systems around the world. Some of the important characteristics of North American distribution system designs and European distribution system designs were described in the previous sections. In this section, we summarize some of the important differences between these designs. These differences will also be discussed in subsequent chapters related to specific technology implementation opportunities.

European Secondary Substations vs. North American Switchgear and Transformers

A key system design difference is the total lack of an MV/LV secondary substation in the North American distribution infrastructure. The secondary substation is of extreme importance to European metering and distribution automation systems. The AMI Collector, RTU, automated MV switches, Fault Detection, and communications infrastructures are all installed at these substations, which also serves to limit the number of potential locations for these automation devices.



Figure 1-29
Interior View of Distribution (MV/LV) Substation

The comparable infrastructure in the U.S. system would involve a MV pad-mounted switchgear (which performs the functions of the MV switches in the European system) and a number of small padmount distribution transformers, which perform the function of the MV/LV secondary substation transformer in the European system. The pad-mounted switchgear comes in a number of configurations with varying numbers of 600-A three-phase switched legs and 200-A three-

The photos below compare the typical North American switchgear and pad mounted transformer with the comparable Italian infrastructure. North American underground equipment is typically installed on concrete or fiberglass pads connected to underground cables that may be installed directly in the ground, in plastic duct, or concrete encased duct-banks. Components necessary to enable automation of switchgear (motor operators, controllers and RTUs) are installed on cabinets attached to the side of the switchgear. Each North American switchgear will serve a three phase loop of 5-20 single phase pad-mounted transformers feeding a residential or commercial area.



Figure 1-30
Comparison of U.S. and European Underground MV Switching Infrastructure



Figure 1-31
U.S. Switchgear Controller and European Secondary Substation RTU

Distribution Transformers

The pad-mounted transformers are typically in the range of 10kVA to 75kVA, depending on the density of the load served, each serving 5-15 customers. Each transformer is also typically implemented with a manual faulted circuit indicator (FCI) which triggers on overcurrent to provide field crews with information necessary to diagnose the location of a faulted cable to a particular section between two adjacent transformers. The European secondary substations typically include one (sometimes two) MV/LV distribution transformers, typically sized 250 kVA to 1000 kVA, each serving 75-250 customers.



Figure 1-32
Comparison of U.S. Pad-Mounted Transformer with European Distribution Transformer

Comparison of Overhead Infrastructure

The OH MV infrastructure in the U.S. is more similar (at least physically) to the OH MV infrastructure in Europe. There is still the difference that European systems usually have MV/LV substations as a critical smart node in the infrastructure while North American systems have pole-mounted transformers supplying much smaller groups of customers. Examples of overhead transformers are shown below.



Figure 1-33
American Three Phase Bank and European Three Phase Transformer

The implementation of protection and automation technologies, like reclosers, on the overhead systems are very similar in North America and Europe. Both are implemented by MV switches/recloser mounted on poles, with a control box containing an RTU, sensing and communications mounted on the pole. The photos below show comparable OH switches/reclosers in North America (NA) and in Europe. Essentially they serve the same function, with the key difference being that the North American versions often have options to enable independent phase switching.



Figure 1-34
Three Phase North American Automated Recloser and Three Phase European Automated Switch

In both the North American and European automation solution, the switches are managed by a combination of an intelligent electronic device (IED) controller, a remote terminal unit (RTU), and some form of communications endpoint device. Both the North American and European OH switches require a controller/RTU to provide an interface between hard wired control outputs, status inputs and sensing inputs with the communications infrastructure. North American MV switch and recloser vendors typically provide an intelligent electronic device (IED) controller as part of the package with their switch, although some vendors have succeeded in marketing IED controllers to deploy with a variety of vendor's MV switches. Examples of North American controllers and European system controllers are shown below.



Figure 1-35
Comparison of North American (SEL 651R, ABB PCD) and European OH Switch Controllers

Single Phase Switching

One additional relevant difference is that North American utilities have the opportunity to perform individual phase fault isolation and restoration, since many rural feeders supply a large percentage of transformers connected between a single phase and the grounded neutral. Additionally, typical North American tariff documents place the responsibility on the customer to protect their three-phase loads from loss of a phase. Given these two key differences, North American switch vendors have developed sectionalizers and reclosers which trip and lockout an individual phase, based on the detection of overcurrent on a single phase.

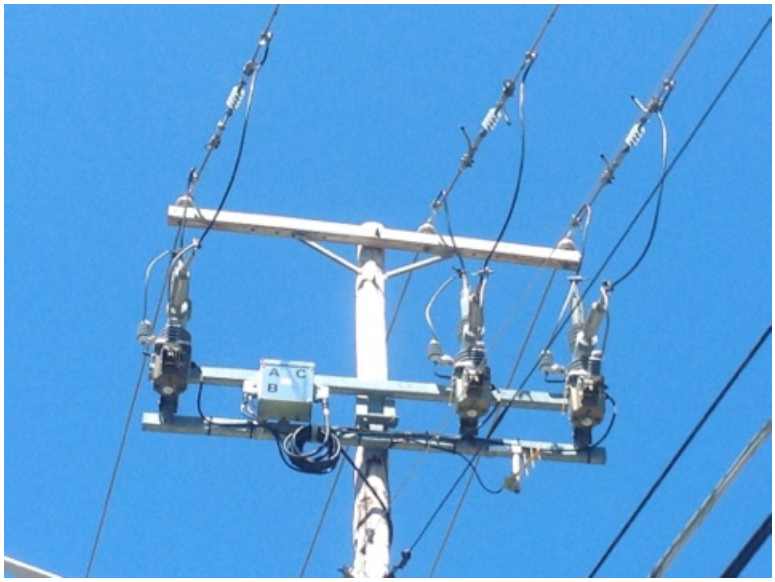


Figure 1-36
Individual Phase Automated Recloser

Utilities have taken advantage of this capability and opportunity to deploy restoration schemes where the fault can be isolated to a single phase of a section of feeder between two automated switches. No comparable capability exists on the Italian system where all transformers are three phase units, and MV/LV transformers are either connected to all three phases or between two phases.

Neutral Grounding and Fault Detection

Another key difference is the different approach to neutral grounding, with North American utilities opting for a solidly grounded neutral and the Italian system going through a transition from an ungrounded to a compensated grounded neutral. The U.S. distribution system is deployed primarily in a 4-wire Wye configuration with a solidly grounded neutral. In this type of effectively-grounded system, significant fault current-generally at least twice high as the load current- is generated when a phase comes in contact with ground, permitting the use of relatively simple overcurrent sensors to detect fault current. However, high-impedance ground fault detection is difficult in 4-wire multigrounded neutral systems because the relay measures the ground fault current combined with the current generated from unbalanced loads and other elements on the system. [1]

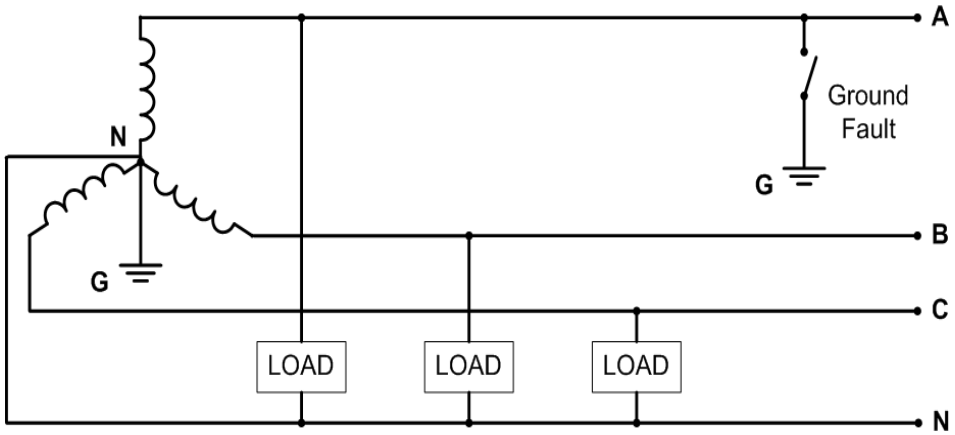


Figure 1-37
Solidly Grounded Neutral - North America

Quite differently, the European distribution system is deployed in a 3-wire Wye configuration with either an ungrounded neutral, or a compensated grounded system where the neutral is grounded through a variable impedance reactor. While there were compensated grounded systems in North America in the past, they no longer exist today. What remain is solidly grounded 4-wire Wye systems, as well as some legacy 3-wire Delta systems (mostly on legacy 4kV systems that have not yet been converted to higher voltage). Some California distribution circuits have a standard practice of connecting loads line-to-line rather than line-to-ground in order to reduce the amount of load current flowing in the ground and neutral but these systems still have solidly grounded neutral systems for fault currents. This reactor compensates the system phase-to-ground capacitance such that the zero-sequence network becomes a very high impedance path. The reactor, known as a Petersen coil, permits adjustment of the inductance value to preserve the tuning condition of the system for different network topologies. European utilities install a resistor in parallel to the Petersen coil, so their operation with fault is limited to one minute, due to the thermal limits of the resistor.

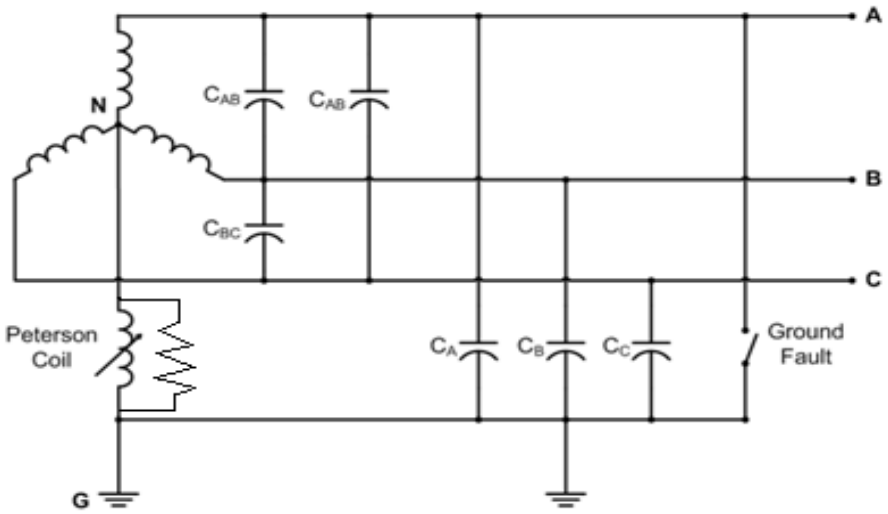


Figure 1-38
Compensated (Resonant Grounding) System - Europe

Issues	Isolated Neutral	Uni-Grounded	Multi-Grounded	Low Z Grounded	High Z Grounded	Resonant Grounded
Example Countries	**Italy, Japan, Spain, Ireland**	**Great Britain, West Coast U.S.**	**U.S., Canada, Latin America, Taiwan, Philippines**	**France, Spain**		**Italy, Northern Europe, Ireland**
MV/LV Transformer Connections	**Ø-Ø**	**Ø- Ø (3wire) and Ø-N (4wire)**	**Ø- Ø and Ø-G**	**Ø- Ø**	**Ø- Ø**	**Ø- Ø**
Operation with ground fault	**Not Always**	**No**	**No**	**No**	**Not Always**	**Almost Always**
Self Extinguishing Ground Fault	**Not Always**	**No**	**No**	**No**	**Not Always**	**Almost Always**
Ground Fault Protection Sensitivity	**Average**	**Good**	**Bad**	**Good**	**Average**	**Average**
Equipment Thermal Stress	**Low**	**High**	**High**	**High**	**Low**	**Lowest**

Table 1-2
Comparison of Grounding Systems Worldwide [1]

Service Connection Differences

Figure 1-38 provides a pictorial representation showing the differences between North American and European practices transitioning from medium voltage (MV) distribution to low voltage (LV) service. The European approach provides multiple three-phase or single-phase services from a three-phase distribution transformer that is significantly larger (250 - 500 kVA) then the single-phase (25 - 50 kVA) transformers utilized in the North American system. In both systems, power quality conditions (voltage regulation, harmonics, unbalance, flicker) on the secondary voltage systems can be impacted by individual customers. In Europe, there are more customers on a secondary system but each customer would have a smaller impact on the overall power quality. In rural applications, there is little difference between the two approaches to service.

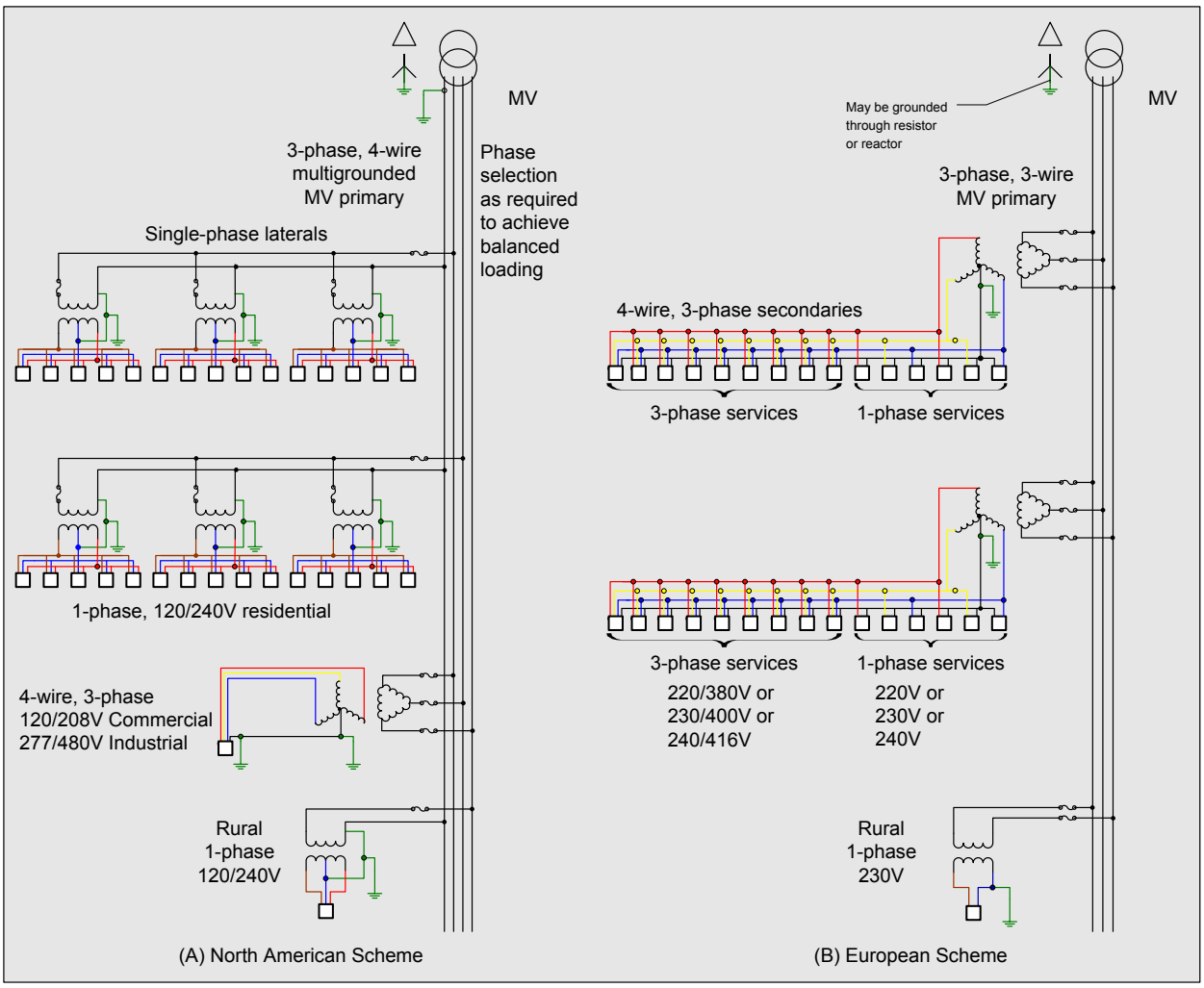


Figure 1-39
North America and European Typical Service Connection Practices (Note: The Monophase or Biphase Connections in the MV Italian Distribution Network are Not Shown) [2]

2
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1. Roberts, Jeff, et al., "*Review of Ground Fault Protection Methods for Grounded, Ungrounded and Compensated Distribution Systems."* Schweitzer Engineering Laboratories, 2001.
2. Short, T. A. "Electric Power Distribution Handbook" CRC Press. Boca Raton. 2014.
3. Roberts, Jeff, et al., "*Review of Ground Fault Protection Methods for Grounded, Ungrounded and Compensated Distribution Systems*." Schweitzer Engineering Laboratories, 2001.

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