

Transitioning to Smart MV/LV Substations as the Cornerstone of Your Smart Grid

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Executive summary

Utilities face increasingly higher expectations to maintain power quality and achieve greater service continuity. With the widespread integration of distributed energy resources all along the network, more Smart Grid capabilities are being introduced into MV/LV substations to meet these expectations. Therefore, transitioning substation assets to host these new capabilities is becoming the neuralgic aspect of any Smart Grid deployment. This paper describes which architectures and components will have the greatest, most effective impact on utilities' transition to smart MV/LV substations.

Introduction

Utilities today face increasing pressure to improve the reliability and efficiency of the electric grid while simultaneously enhancing power quality. They must also support a higher ratio of distributed energy resources (DER) — such as renewable energy sources, distributed storage, and electric vehicle charging stations — connected to medium voltage (MV) or low voltage (LV) distribution levels.

Innovative Smart Grid solutions exist today to help meet these challenges. As the heart of any electrical power distribution system, MV/LV substations house the switches, capacitors, transformers, and other assets used to keep grid power flowing, balanced, and routed appropriately. These substations, located most closely to the vast majority of grid users, are becoming the cornerstone of the electricity grid evolution. Transitioning MV/LV substations' assets to host these new smart capabilities is becoming the neuralgic aspect of any Smart Grid deployment.

Specifically, MV/LV substations can leverage this smart technology to:

- Improve the quality of service
- Better balance LV feeder loads
- Manage voltage limits
- Optimize assets and reduce field site visits
- Improve smart meters return on investment
- Avoid unwanted “islanding”

This paper discusses how different electromechanical and communications architectures affect MV/LV substations' ability to meet these 6 challenges, explores various Smart Grid components, identifies which equipment offers the best opportunities to have the highest impact, and explains the advantages of deploying pre-engineered solutions.

Real-life examples of Smart Grid deployments

Many cases of Smart grid deployments have been in existence worldwide for 15 years. However, they have often been limited by the cost of implementation and communications challenges. Over the last few years these obstacles have been largely overcome, as the Internet of Things (IoT) has made better communication feasible and devices like smart sensors are now more affordable. Some examples of Smart Grid solutions that are already in place to meet today's challenges follow:

- One of the largest utilities in the Netherlands, with over 2 million customers, needed to reduce the duration of power outages. The challenge was to come up with a high-quality, cost-effective means of quickly re-energizing the MV network in case of a fault. By introducing smart capabilities to the existing MV/LV substations, in the case of a fault, the system cuts the time to re-energize the unaffected parts of the grid from an average of 2 hours to around 20 seconds.
- Regulated distribution transformers (smart MV/LV transformers that control the tap changer based on information received from several LV monitoring points along the grid) are being used to control voltage fluctuations induced by distributed energy resources. Some of these transformers have been installed in France for over a year with positive results.
- Greenlys, a full-scale Smart Grid demonstration pilot project in France involving 1,000 residential customers and 40 commercial building sites, has found that smart meter communication architecture helps monitor the LV feeders and the phases on which loads are connected. This allows easy phase rebalancing to allow higher level of integration of photovoltaic energy.

- One of the largest utilities in Middle East, with over 6 million customers, is modernizing part of its distribution network. As the area is very wide — more than 10,000 electrified towns and villages — the duration of network outages caused by faults may be lengthy because maintenance staff need to drive to often-inaccessible faraway locations to manually isolate the faulty sections. The modernization project will limit outage duration through smart monitoring and remote control features. Motorized ring main units equipped with fault passage indicators, connected to remote terminal units and supervised by a SCADA system, immediately identify and isolate the faulty sections remotely, i.e., from the control room.

Some terminology

Defining common terms avoids any possible confusion when discussing concepts and best practices. Below are a few terms that are utilized in this white paper and their definitions.

- The **Smart MV/LV** concept is discussed from a historical point of view, relating to the presence of ring main units (RMUs) with remote terminal units (RTUs). This concept can be extended to topologies with reclosers and pad-mounted units, such those used in United States.
- **Distributed energy resources (DER)** include a variety of supply-side and demand-side resources such as distributed generators (renewable or not), controllable (or flexible) loads used for demand response, energy storage (electrical or thermal), and electric vehicles (which play a dual role in both load and energy storage).
- **High presence of DER** significantly influences the design of the feeder and its protection. The presence of DER is said to be “high” when the current contribution from DER downstream from the considered grid location for a fault located upstream (even on another MV feeder connected to the same HV/MV or MV/MV transformer) is comparable to short circuit current generated by a fault located downstream.
- **“Islanding”** is where a distributed generator (DG) or a set of DGs continues to power a portion of the grid when the connection to the main public electrical grid power is no longer present.

6 Smart Grid opportunities & challenges

“The Internet of Things (IoT) has made better communication feasible and devices like smart sensors are now more affordable.”

1. Improving quality of service

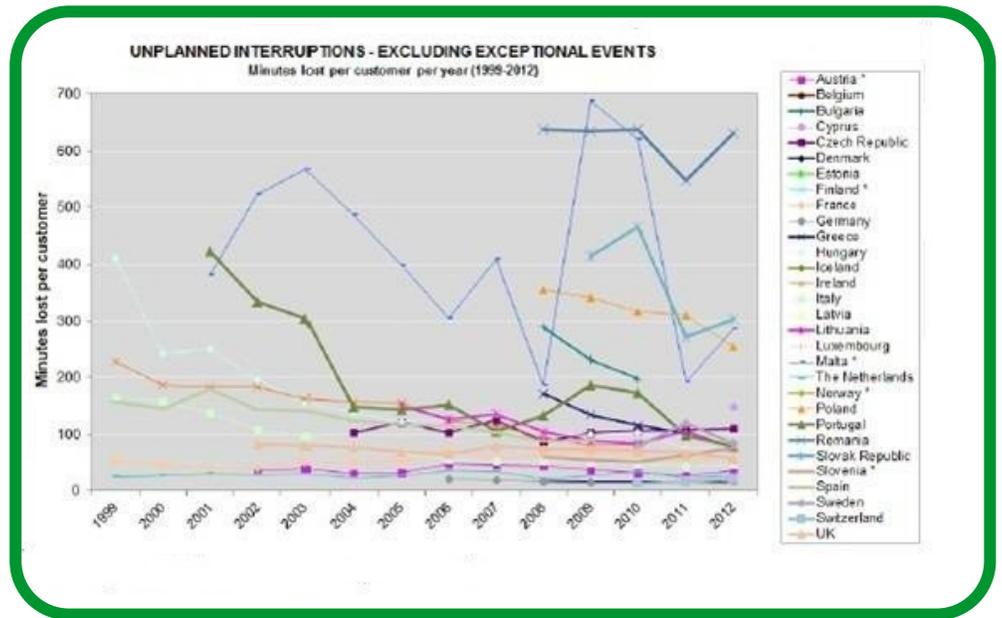
As electricity is the primary source of energy for homes, buildings, and industry worldwide, utilities are increasingly sensitive to quality of service. The quality of utilities’ supply of electricity is measured and published in indexes, e.g., the Council of European Energy Regulators (CEER) Benchmarking Report on the Continuity of Electricity Supply. An analysis of this report shows that the average annual interruption time for customers connected to distribution network varies, depending on the country, from 10 to 700 minutes per year. Although all countries have shown a downward trend since 1998, some still have an average annual interruption time of more than 100 minutes per year — too high for end users in homes, buildings, and industry. Utilities often use other reliability indicators — specifically, the System Average Interruption Duration Index (SAIDI), which calculates the average outage duration for each customer served, and System Average Interruption Frequency Index (SAIFI), which calculates the average number of interruptions that a customer would experience — to track and benchmark their reliability performance. See **Figure 1**.

One of the primary factors impacting quality of service is whether the distribution grid is overhead or underground. In general, underground grid have much better performance than overhead ones; however, using smart technologies is one of the first ways to reduce the difference in performance.

Traditional MV/LV substations in public distribution applications are equipped with ring main units (RMUs) with switch-fuse solutions or circuit breakers for MV/LV transformer protection, and manually operated load break switches for cable switching. When a fault occurs, a crew

has to be sent into the field in order to identify the location of the fault, possibly helped by checking the position of the fault passage indicator (FPI) in different substations, if such devices are installed on the concerned feeder. This is time-consuming and costly, and may lead to long outages. The presence of DER makes the detection of faults even more sophisticated, and may require these FPIs to be of the directional type. When a distribution network is operated as an open loop, strategic electrical nodes (including the normal open point) need to be equipped with specific remote capabilities, including motorized switches and FPIs. In countries using a long-line radial design (e.g., United States, South America, Middle East, Australia), smart reclosers can clear electrical faults closest to where they happen, rather than exclusively clearing them at the primary substation, requesting then that these smart reclosers be connected to the outage management center to communicate that a fault has occurred. Otherwise, the grid operator may miss the event and many grid users would be left without power.

Figure 1
Unplanned SAIDI, excluding exceptional events



2. Better balancing LV feeder loads

The LV ends of distribution networks are often heavily unbalanced between transformers, between LV feeders within a transformer, and between the three phases of one given transformer. With the massive injection of distribution energy resources (e.g., photovoltaic panels), these imbalances are amplified. These imbalances cause joules losses in wires and transformers due to the higher current level on the more heavily loaded part of the network and to current flow in neutral wires that were usually not designed for such a situation.

In the case where LV feeders are equipped with energy meters connected to the remote terminal unit (RTU) in the substation, the system is able to calculate imbalances on LV feeders in real time (every 10 minutes, on average) and to locate each LV consumer on the network, feeder, and phase. The re-balancing of loads may be performed by repartition units installed along the LV feeder that switch a targeted group of grid users from one phase to another.

Imbalances also create unexpected voltage drops (see “Managing voltage” below).

3. Managing voltage

One of the main responsibilities of utilities around the world is to maintain voltage fluctuations within limits as contractually agreed to (i.e., +/- 10% of agreed-upon target as requested in network codes). Voltage control has traditionally been performed by transformers, using on load tap changers and capacitor banks that inject reactive power into the grid, located at the HV/MV substation level. The distribution system operator (DSO) fixes a setpoint and prepares scenarios and ranges based on forecasted load and production curves, for example.

As a result of the massive integration of DER into the MV/LV grid, voltage management now presents DSOs with major challenges. Cases may differ depending on whether the DSOs' coverage area is urban or rural, and on the type and density of DER connected. They now have to manage situations where voltage may be rising on one part of the grid while decreasing on another, or deal with the unexpected behavior of DER due to weather conditions. Consequently, DSOs are deploying sensors to monitor the voltage all along feeders, new actuators that are able to regulate the voltage at different levels, and centralized or distributed intelligence to optimize voltage control — for example, equipping the MV/LV substation with a regulated distribution transformer (smart transformer) with on load tap changer and an associated controller that receives information from several LV monitoring points along the grid. See **Figure 2**.

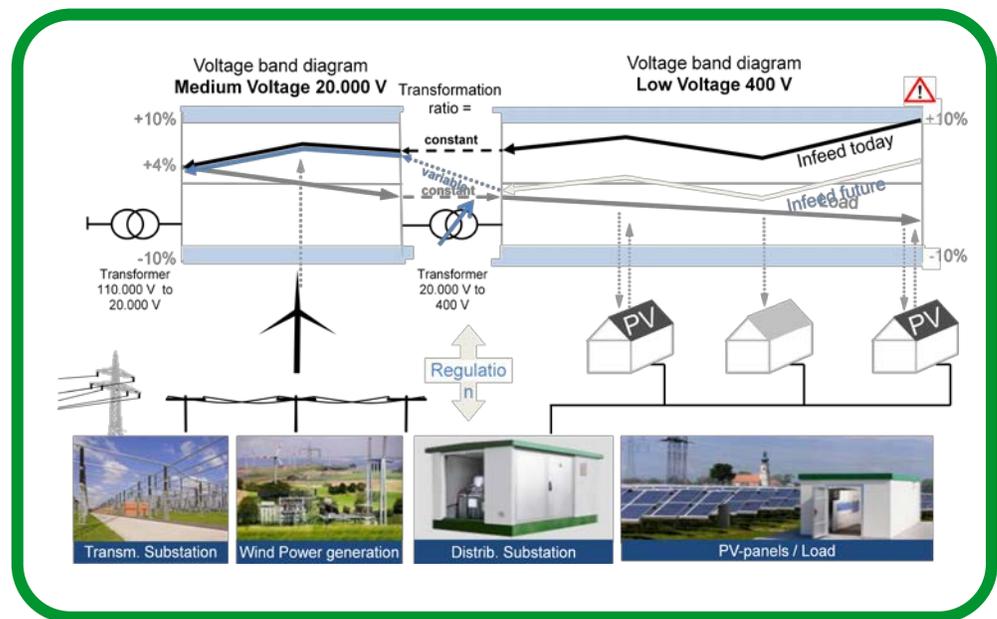


Figure 2
Smart transformers regulate voltage

4. Optimizing assets & reducing field site visits

Utilities are facing increased pressure to reduce their capital expenditures (CAPEX) and operational expenditures (OPEX). With a huge portfolio of valuable assets, distribution utilities look for any means to optimize the use of existing assets, extend their lifetime, and reduce the cost of operating and managing them. This pressure is even more pronounced in light of the changes needed to support a higher rate of DER.

Deploying smart capabilities on the feeder increases utilities' ability to manage assets remotely. Sophisticated, meaningful data are shared among mobile field crews, remote operators, and maintenance centers thanks to smart communication standards. More accurate information about asset behavior enables utilities to not only reduce the number of costly field maintenance visits but also more proactively keep equipment operating efficiently.

5. Improving smart meters return on investment

Because in many cases deploying the communication infrastructure to manage smart metering and installing these smart meters may not provide sufficient financial benefit from a billing perspective (vs. a traditional process), many utilities are seeing greater return on investment by leveraging smart meter data to optimize their distribution networks. Smart meters that communicate through Power Line Carrier (PLC) technology allow utilities to deploy a full set of functions simultaneously, better regulate MV voltage, optimize the integration of DER with local load and production flexibility, and better monitor the LV network and solve LV phase balancing. Aggregated measurement may also help detect non-technical losses at the feeder level.

“MV/LV substations are the critical point of PLC-based smart metering measurement.”

MV/LV substations are the critical point of PLC-based smart metering measurement aggregation because, by design, all connected smart meters communicate through the PLC with the substation they are attached to. When measurements are given to the concentrator located in the MV/LV substation — and assuming the grid operator is granted the right to treat such data (under cyber-security rules) — it can automatically verify/adapt the voltage profile along the LV feeders, verify/adapt the load balance between phases, and compute potential non-technical losses.

6. Avoiding unwanted islanding

“Islanding” is where a distributed generator (DG) or a set of DGs continues to power a portion of the grid when the connection to the main public electrical power grid is no longer present. Unwanted islanding appears when the concerned part of the grid and the connected users have not been specified to run in such a way. Two circumstances primarily cause such a situation:

- Protection devices located at a DER site may be blind: they cannot properly detect the occurrence of this case and then do not trip.
- Incorrect operation of a switch or breaker may create islanding conditions, such as opening a feeder breaker without having requested all concerned DER to disconnect.

It is important to avoid unwanted islanding not only because it may lead to safety hazards for utility field personnel but also because DG units and network components may be damaged as a consequence of unsynchronized reclosing of the islanded circuit, unregulated voltage and frequency, overloaded DER, and undefined earthing. In addition, customer loads in the islanded circuit may be damaged due to poor/unmanaged power quality or to the change of a non-adapted earthing system.

Anti-islanding protection, also known as loss-of-mains protection, has traditionally been installed only at industrial sites connected to the primary substation. But the massive injection of DER, combined with the increased number of microgrids connected at any point along the distribution network, has led utilities to reconsider. For example, very tight voltage and frequency settings reliably detect islanding but now pose a risk to system stability since the voltage and frequency will drop even more after the tripping of the DG. Therefore, protection based on communications with the MV/LV substation creates a more flexible, localized option.

One effective way to avoid unwanted islanding involves communication capabilities between components attached to a feeder. The principle is to force a disconnection by asking the feeder components — which have the knowledge of islanding conditions — to communicate with all attached DER. In the case of a feeder fault, this is known as a “trip transfer” function. It consists of downstreaming a “disconnect/zero power” request, through digital communication links, to all MV/LV substations located along the concerned feeder, as well as to all MV-connected DER and then from these MV/LV substations to all LV-connected DER.

Types of electro-mechanical architecture

A high degree of DER significantly influences the design of the feeder and its protection. As defined previously, the presence of DER is “high” when the current contribution from DER downstream from the considered grid location for a fault located upstream (even on another MV feeder connected to the same HV/MV or MV/MV transformer) is comparable to short circuit current generated by a fault located downstream.

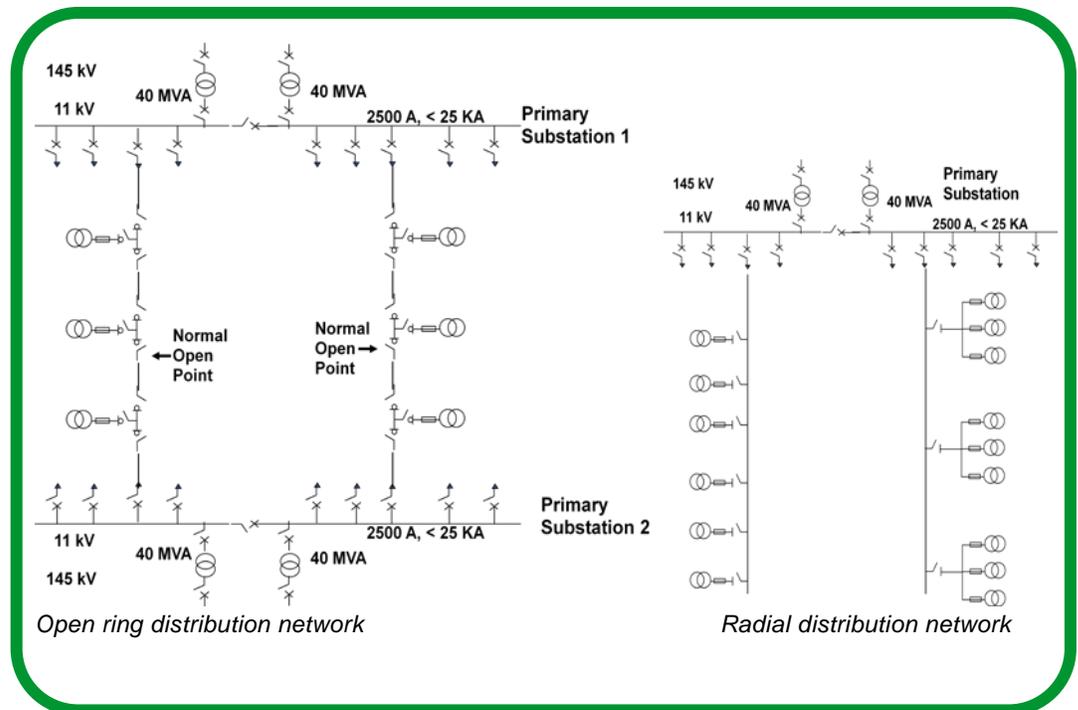
Circuit-breaker only at the primary substation

Traditionally, distribution networks have been operated as either open rings or radial feed networks. See **Figure 3**. The network design was largely influenced by legacy network architecture and/or by the objectives and restrictions of the DSO: power quality targets (such as SAIDI and SAIFI), voltage quality, budget limitations, geographical distribution of loads and DER, targeted value for maximum short circuit current, and possible future expansion.

Without a high presence of DER, network topologies use components with basic protection: protection devices for the main circuit breaker feeders of the primary substation, load break switches along the distribution networks and in the switching substations, fuses or circuit breakers for the distributed MV/LV transformers, fuses and/or circuit breakers on each LV feeder. With a high presence of DER, directional features are added to every protection and fault location device. For both ring and radial networks, if no additional means are provided to field crews, detecting a fault, locating the fault, and restoring power may take a long time.

Figure 3

Distribution networks have been operated as either open rings (left) or radial feed (right) networks.



Open rings are often used to increase the availability of power. A first level of improvement consists of connecting the two ends of the ring to two possibly different primary substations. This architecture offers redundant supply for each ring, with a smaller proportion of the load disconnected in case of a primary substation blackout.

A radial distribution network is the simplest system configuration for widely distributed loads over a large area — e.g., rural MV networks. The occurrence of a single fault results in the complete loss of supply to the load, but it is easy to protect with time-graded overcurrent.

Circuit breakers vs. switch-along feeders

Centralized feeder protection vs. distributed feeder protection

Network topologies using circuit breakers only at primary (HV/MV) substations affect all end users along the feeder in case of a fault leading to outages. This leads to poor SAIDI and SAIFI performance numbers. With a high presence of DER in several distribution networks, this may lead also to a significant financial loss due to “non-produced energy” for prosumers or “non-distributed energy” for DSOs.

Adding circuit-breakers (reclosers) in distribution network feeders, mostly in overhead networks where transient self-cleaning faults occur frequently, is an efficient way to (1) decrease the number of end users affected by an outage and (2) reduce the amount of non-produced energy and non-distributed energy, respectively. Protection attached to the circuit breakers needs to be set adequately to discern the fault most closely to where it occurs (chronological selectivity or logic selectivity). Protection devices need to communicate to the grid operator to ensure that the outage is known to the control center and that the outage for the concerned users won't last too long.

Fuse switches vs. circuit breakers to protect MV/LV transformers

In public distribution applications such as MV ring network configurations for substations that are dispersed over a large geographical area, utilities look for the simplest repetitive approach. The power of an MV/LV transformer is generally limited to 630 kVA or less. Compact and often non-extensible three-function switchgear are often specified by the utilities. In these cases, and if DER presence is low, protection of MV/LV transformers by MV fuses offers an optimized solution.

Protecting MV/LV transformers with circuit breakers is usually done for large commercial, industrial, and building applications — especially when the transformer power exceeds 800 kVA. In these instances, switchboards made of modular units provide great flexibility.

The protection chain of each unit may include self-powered relays with optimized current sensors, which bring a high level of availability and safety. This solution provides maintenance benefits and improves protection of the transformer, discrimination with the LV installation, insensitivity to the inrush currents, and detection of low earth fault currents.

Directional features for high DER presence

In case of a fault, DER will feed the fault current even if the fault is not located downstream of the MV/LV transformer. A consequence of this situation is a reversed current flow direction. This may lead the fuse or the circuit breaker in charge of protecting the loop to trip. Avoiding such a situation may require protection/fault location devices that are able to discriminate the direction of the energy flow.

Local transfer switch (such as ATS)

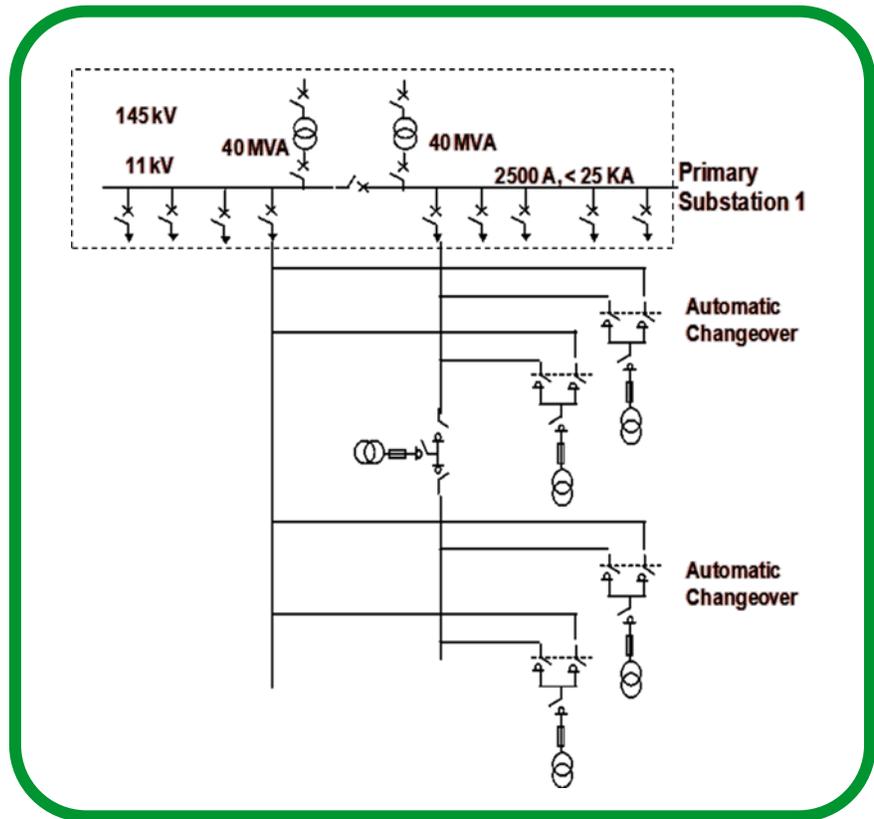
Automatic transfer switching (ATS), or automatic changeover, is the traditional scheme used to improve local power availability, allowing the utility to balance loads from one incomer to another incomer in case of an outage. See **Figure 4**.

Double radial distribution network

The scheme called “double radial” is a kind of native self-healing network that uses redundant cables. This architecture is used in Paris, Moscow, and other cities to dramatically increase the availability of the network — but with an additional cost.

Figure 4

Automatic transfer switching (ATS), or automatic changeover, balances loads from one incomer to another in case of an outage.



Local automatism in the substation

ATS is used by large grid users to secure a critical load with two or more incomers fed by different sources. Buildings, hospitals, malls, or other local infrastructure such as small ports, small airports, and campuses usually have a dedicated controller hosting the ATS function. It automatically resupplies the loads from the backup incomers or from the generators, providing transfer within few seconds. It may also automatically optimize the use of local generators during peak demand and maintenance periods.

Automatic transfer switch for industrial customers

In the case of large industrial customers, ATS is included in the substation automation functions and is managed in a consistent way with the generators and busbar coupling protection to resupply the critical loads in about 200 ms.

VVAR regulation at main substation

Volt-VAR (VVAR) regulation must maintain acceptable voltages at all points along the feeder under all loading conditions and also efficiently optimize the reactive power and the voltage. The Volt-VAR of the distribution network is controlled mainly at the primary substation level with a load tap changer (LTC) and capacitor banks.

The LTC changes the rate of the HV/MV transformer and then regulates the substation bus voltage by means of an LTC controller called an automatic voltage regulator (AVR). The AVR regulates the voltage using an estimation of the end of lines based on loads, and in some cases also using a reference setpoint calculated by the distribution management system (DMS). LTCs are not sufficiently flexible to accommodate the massive integration of DER and require costly maintenance because of the increased frequency of changing orders due to the fluctuating availability of solar and wind power.

One major source of system losses is the reactive load, which is created mainly by load devices with electric motors. Examples are washing machines and air conditioning units. VAR load also increases the need for system capacity. Consequently, utilities have been using locally regulated capacitor banks to reduce the amount of VAR on their systems. However, the voltage and VAR controls are generally not coordinated, resulting in underperforming distribution systems.

Distributed VVAR

Some Volt-VAR control devices may also be distributed along the feeder or at the customer connection. These devices can adapt the rough regulation made at the primary substation, taking into account the local network specifics in terms of length and capacity of the lines, loads and generation, storage, and load curtailments.

Traditional solutions are fixed line capacitors and fixed tap changers of MV/LV transformers. These devices are tuned in order to have an acceptable voltage under loading conditions on each end of the feeders. Nowadays, due to DER, more devices are installed along feeders to compensate for voltage fluctuations.

Different from the traditional distribution transformers, smart transformers meet dynamic voltage regulation needs and are an attractive option for utilities to meet their future distribution network challenges. Furthermore, such smart transformer equipment may improve visibility into the distribution grid thanks to their ability to communicating with remote centers.

New types of power electronics devices, like the mid-line power regulators or other static VAR units, enable renewable generation connections without affecting existing power quality. These devices, while more expensive than traditional solutions, combine significant advantages like voltage regulation under forward and reverse power flow, fast reactive power compensation, current harmonic cancellation, power quality improvement, and phase balancing.

Table 1
Different electromechanical architectures and how they help realize the 6 Smart Grid opportunities

Architecture	Smart Grid abilities
Circuit breaker only at the primary substation, RMU with switches	<ul style="list-style-type: none"> (1) Improve quality of service, but limited
Breaker only at the primary substation, RMU with controlled switches	<ul style="list-style-type: none"> (1) Improve quality of service (4) Optimize assets & reduce field site visits
Circuit breakers vs. switch-along feeders	<ul style="list-style-type: none"> (1) Improve quality of service (4) Optimize assets & reduce field site visits
Local transfer switch (such as ATS)	<ul style="list-style-type: none"> (1) Improve quality of service
Smart regulated distribution transformers & Volt-VAR devices	<ul style="list-style-type: none"> (3) Manage voltage

Boldfaced capabilities denote high impact

Types of communication architecture

No digital communication

In architectures with no digital communications (see **Figure 5**), fault passage indicators (FPIs) allow the operator to manually identify the faulty section. However, such identification takes time because it forces the operator to go into the field and travel from FPI to FPI, possibly all along the feeder.

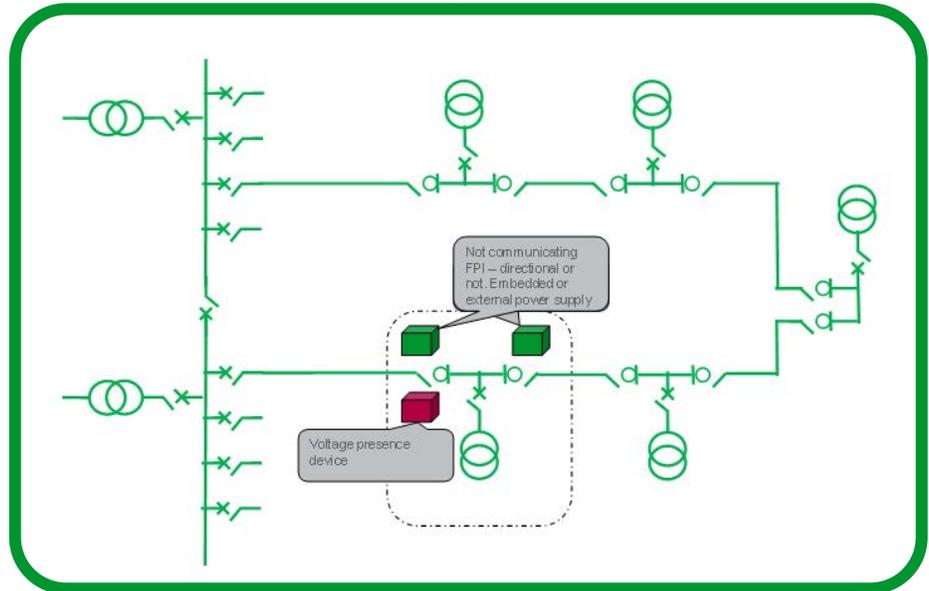


Figure 5

Without digital communications, operators need to go from FPI to FPI to find the faulty section.

Digital communication with remote monitoring

An architecture (see **Figure 6**) that relies on a central supervisory control and data acquisition (SCADA) software and related components (such as advanced distribution management system [ADMS]) enables an operator to know the status of each FPI remotely. Control is still performed manually on the field, but maintenance activities may be optimized by immediately focusing the field crew on the faulty section.

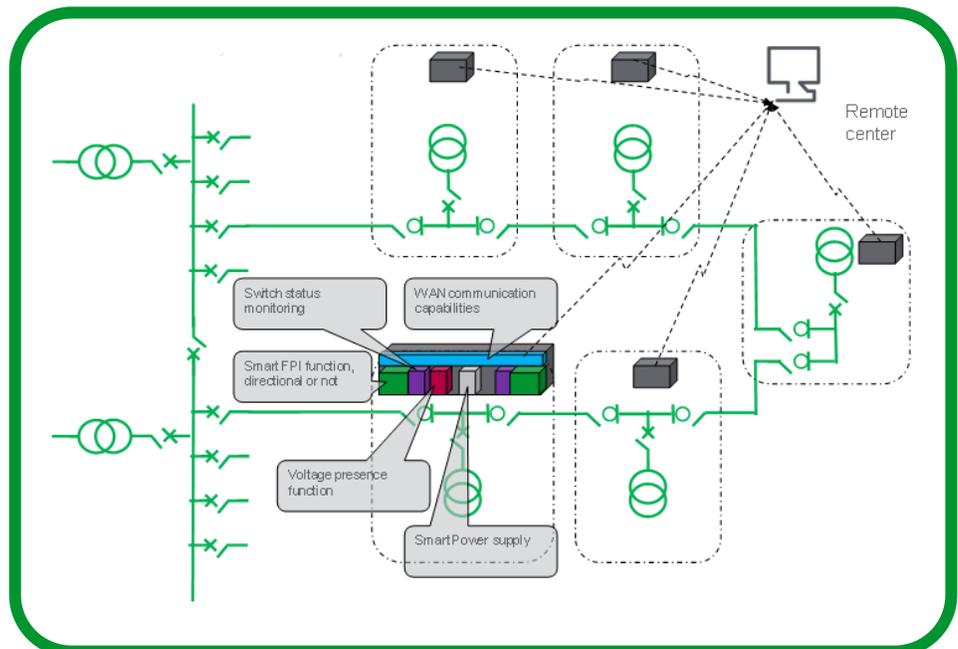


Figure 6

Communications that leverage SCADA software provide greater visibility into the status of each FPI remotely.

Digital communications with remote monitoring and control

This architecture (see **Figure 7**) presents all the advantages of the previous one plus the ability to control remotely. It also offers the possibility of optimizing the reconfiguration process based on the topology as well as load and generation status.

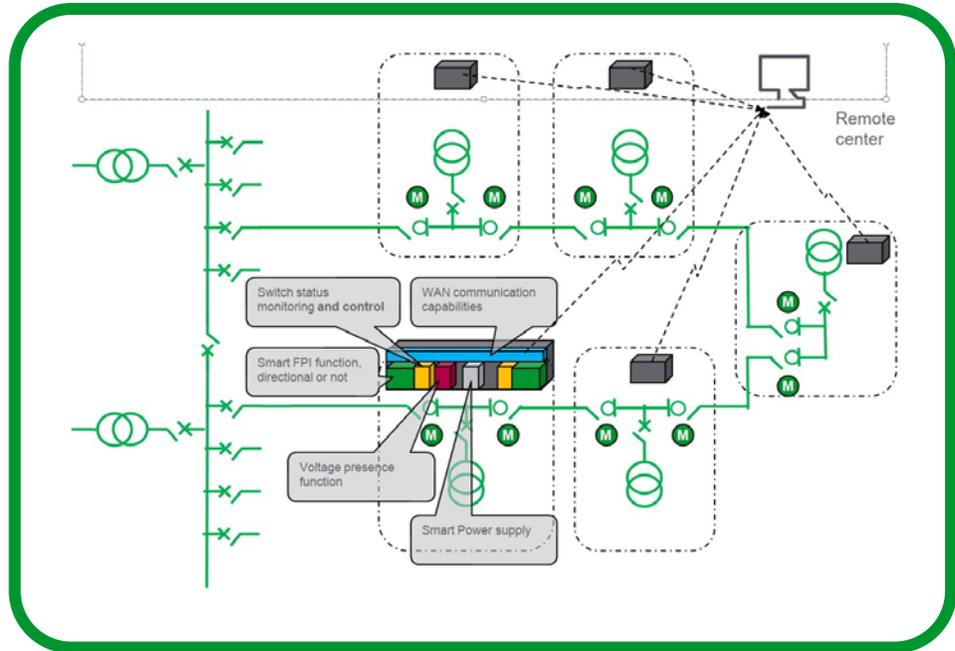


Figure 7
LV controllable switches enable not only the ability to monitor FPIs remotely but also control them remotely.

Peer-to-peer communication

Peer-to-peer architectures (see **Figure 8**) offer stand-alone capabilities which very often are more reactive than architectures based on central means. Each smart component located along the feeder can benefit from communicating with its neighbors to perform distributed automation such as fault location, fault isolation or Volt-VAR control without been requested to communicate with a remote control center.

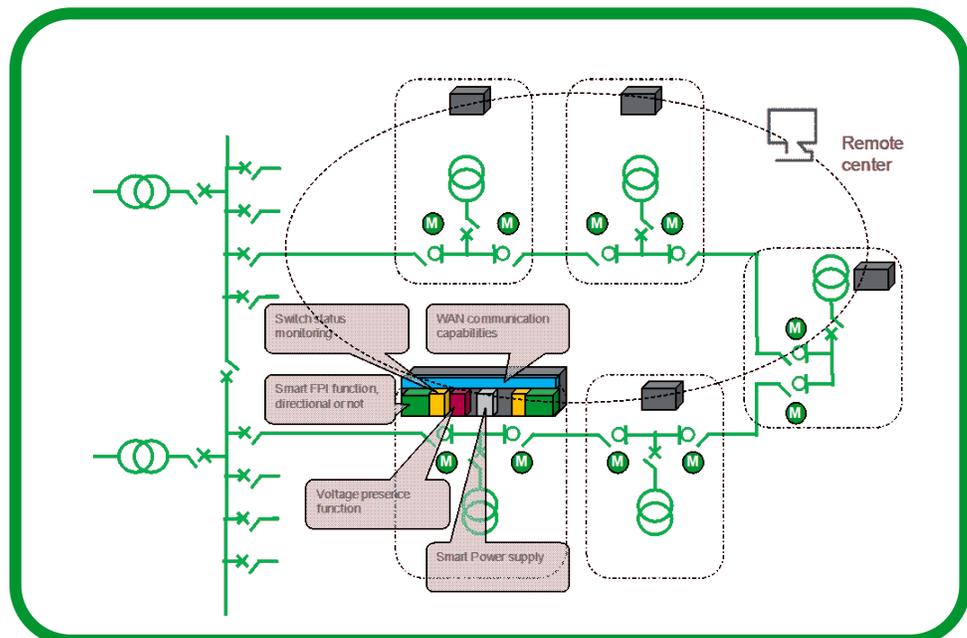


Figure 8
Peer-to-peer communication is usually more reactive.

Table 2

Different communication architectures and how they help realize the 6 Smart Grid opportunities

Architecture	Smart Grid abilities
No digital communication	<ul style="list-style-type: none"> (3) Manage voltage , but limited
Digital communication with remote monitoring – more observability	<ul style="list-style-type: none"> (1) Improve quality of service (2) Balance LV feeder loads (3) Manage voltage limits (4) Optimize assets & reduce field site visits (5) Improve smart meters return
Digital communication with remote monitoring and control – more controllability	<ul style="list-style-type: none"> (1) Improve quality of service (3) Manage voltage limits (4) Optimize assets & reduce field site visits
Peer-to-peer communications	<ul style="list-style-type: none"> (1) Improve quality of service (3) Manage voltage limits (4) Optimize assets & reduce field site visits (6) Avoid unwanted islanding

Boldfaced capabilities denote high impact

When looking to match the appropriate communication technologies to the different architectures, it is important to differentiate the communication layer (protocol specification) from the information layer (i.e., data model and semantics). See **Table 3**.¹

In any case, choosing the technology from an international standardization body offers the utility the possibility to deploy multi-vendor solutions and finally secure their investment.

Table 3

Communication technologies and standards to interconnect the smart MV/LV substation, per typical architecture

Architecture	Communication layer	Information layer
Digital communication with remote monitoring	<ul style="list-style-type: none"> IEC 60870-5-101 or 104 DNP3 (IEEE 1815) In future IEC 61850-8-2 	IEC 61850*
Digital communication with remote monitoring and control	<ul style="list-style-type: none"> IEC 60870-5-101 or 104 DNP3 (IEEE 1815) In future IEC 61850-8-2 	IEC 61850*
Peer-to-peer communications	<ul style="list-style-type: none"> IEC 61850-90-5 	IEC 61850*
	<ul style="list-style-type: none"> •For observability and control IEC 60870-5-101 or 104 DNP3 (IEEE 1815) In future IEC 61850-8-2 	IEC 61850*

**Using the IEC 61850 helps bringing semantics to the communication making the integration of the subsystem much easier.*

¹ IEC 61850 can be easily mapped over IEC 60870-5-101/104 thanks to the TS IEC 61850-80-1, or DNP3 thanks to the IEEE 1815-1. Such a mapping can fully benefit from the IEC 61850 system configuration language, to get a formal machine readable description.

Smart components

Low power voltage sensors: Low power voltage transformers (LPVT) for voltage metering offer new convenient (low cost, weight, footprint) ways to measure voltage and to calculate all associated data needed for advanced automation, such as active and reactive power, power factors, and energy and fault direction.

Smart FPI: Electronic and communicating FPI not only notify operators of a fault but also indicate the type of fault and count the number of faults per period. Because of its location on a specific point of the feeder, a smart FPI may also help monitor the usage of the feeder by providing the circulating current, its direction, the voltage, and the amount of power (active and reactive). It may also receive from remote the feeder status and warn connected distributed generation sources of the feeder status and then help avoid islanding part of the grid.

Smart ring main units (RMUs) are MV actuators (switches and circuit breakers) present on the feeder which can be operated remotely — to isolate a faulty section, for example. Very often motorized, they can also be operated with a minimum of available energy. RMUs become “smart” with embedded electronic and sensors. Such smart RMUs may provide additional pre-engineered integrated functions (such as FPI, power measurement, switch control, and protection) with the same footprint. Being instrumented, they may also monitor conditions and support condition-based maintenance.

Smart reclosers: One schema could be to clear electrical faults the closest to where they occur, rather than exclusively at the primary substation. This is particularly relevant in the case of overhead distribution. Smart reclosers, capable of communicating with control centers, can then inform these centers of customer outages. By offering peer-to-peer communication with other reclosers, they enable automatic fault isolation and service restoration without involving the control center.

Smart power supply is an uninterruptable power supply controlling an external battery and equipped with communication capabilities to the local RTU. The local power supply is needed both to communicate and to operate the switches remotely. Having the capability to monitor and test the health of the local battery and the battery charger contributes to reaching SAIDI objectives and to reduce battery maintenance costs.

“ADMS is crucial to realize the maximum benefit from smart MV/LV substations.”

Smart transformers include actuators that could help manage voltage and active and reactive power. They are most often installed at the HV/MV substation level (on load tap changers within HV/MV transformers, capacitor banks, and voltage regulators) but can also be installed along MV lines or even further downstream. These transformers can help automatically regulate the MV voltage in order to increase or decrease the LV voltage, and keep it within the allowed range. Such regulation can take into account line drop compensation and/or weather forecasts. In the case of intermittent production down on the feeder, voltage changes may be requested at a very high rate, compared to traditional usage. One requirement of such a smart transformer would be to withstand 1 million operations during its life cycle with limited maintenance. When communicating either to remote centers or peer-to-peer with other field devices, they can optimize their functioning.

In-line power electronics are used more and more frequently for the same reasons as smart transformers. They may be located either at end user site or along the feeders at the MV or LV level. They can be very efficient, contributing to power factor management, voltage management, phase rebalancing, and even frequency regulation in the future.

Smart LV sensors: The presence of active consumers or producers (especially intermittent ones) on the LV part of the grid raises the need to monitor it. Retrofit solutions are available to easily spread smart sensors on existing installations.

Smart MV/LV controller (feeder RTU): The MV/LV substation is becoming the cornerstone of distributed automation to help utilities improve power quality and assets' lifespan. Smart controllers can maximize the benefits of smart assets by hosting some local automation — or, in the case of conventional assets (RMUs, transformers), a dedicated function — and by communicating with control centers or with other substations using standard protocols (IEC 61850). This also includes the capability to accurately monitor the quality of delivered energy. One interesting aspect is that such an approach may also apply to existing substations, retrofitting them to open a new field of smart applications. To ensure robust, reliable remote control of the MV network, the RTU and each connected electronic device, like the smart power supply and smart FPI, have to meet a high level of electromagnetic compatibility immunity (EMC standards) that traditional industrial controllers do not reach .

Advanced Distribution Management System (ADMS): ADMS (including SCADA and topological display and calculation, flow monitoring and remote control of switches) enables a level of grid monitoring and control that is crucial to realize the maximum benefit from smart MV/LV substations. Volt-VAR control gives operators the ability to centrally and remotely manage voltage at the feeder level by controlling field actuators such as tap changers and smart transformers. Fault location, isolation and supply restoration (FLISR) centrally and remotely manages all smart devices located on the feeders, with the objective of locating faults accurately and quickly, isolating the faulty section, and restoring power to a maximum number of grid users. ADMS offers ways to handle asset databases and connect real-time data retrieved from the field to the corresponding assets. It can then efficiently contribute to optimizing the use of assets (extending their life duration by avoiding assets operating beyond their limit) as well as reducing the costs of maintenance.

Smart component	Smart Grid abilities
Low power voltage transformers	<ul style="list-style-type: none"> (2) Balance LV feeder loads (3) Manage voltage (6) Avoid unwanted islanding
Smart FPI	<ul style="list-style-type: none"> (1) Improve quality of service (4) Optimize assets & reduce field site visits (6) Avoid unwanted islanding
Smart Ring Main Unit (RMU)	<ul style="list-style-type: none"> (1) Improve quality of service (4) Optimize assets & reduce field site visits
Smart recloser	<ul style="list-style-type: none"> (1) Improve quality of service (4) Optimize assets & reduce field site visits
Smart power supply	<ul style="list-style-type: none"> (1) Improve quality of service (4) Optimize assets & reduce field site visits
Smart transformers	<ul style="list-style-type: none"> (3) Manage voltage (4) Optimize assets & reduce field site visits
In-line power electronics	<ul style="list-style-type: none"> (2) Balance LV feeder loads (3) Manage voltage
Smart LV sensors	<ul style="list-style-type: none"> (1) Improve quality of service (2) Balance LV feeder loads (3) Manage voltage (4) Optimize assets & reduce field site visits (5) Improve smart meters return
Smart MV/LV controller	<ul style="list-style-type: none"> (1) Improves quality of service (4) Optimize assets & reduce field site visits (6) Avoid unwanted islanding
ADMS	<ul style="list-style-type: none"> (1) Improves quality of service (3) Manage voltage (4) Optimize assets & Reduce field site visits (5) Improve smart meters return

Boldfaced capabilities denote high impact

Table 4
Various smart components and how they help realize the 6 Smart Grid opportunities

The benefit of pre-engineered solutions

The key concept behind pre-engineered solutions is to build smart features upon an existing electrical network. For example, it is difficult to deploy a new self-healing system on a live network because installing, testing, and commissioning the system would cause so many outages.

A pre-engineered solution is well adapted to a distribution network with a large number of homogeneous devices and repetitive network topologies. A solution that has been standardized, industrialized, and fully factory-tested beforehand saves commissioning time, reduces the number of voltage outages during installation, and is flexible enough to accommodate future network development.

Self-healing solutions

A decentralized, pre-engineered self-healing solution is well adapted for an open ring distribution network. One such solution was recently deployed in Rotterdam on an underground feeder. The concept is simple and easy to extend with a meshed network using peer-to-peer digital radio communication services between each RMU. In January 2015, a major outage incident was avoided: 14 secondary substations (affecting 600 customers) were reconfigured and reconnected in 18 seconds rather than the previous average of 2 hours.

Due to their higher vulnerability, a self-healing solution for overhead lines that uses a combination of reclosers and sectionalizers would be recommended. Traditionally the so-called loop automation solution that uses recloser cycles and delays to reclose the ring on the tie point allows for isolating the fault and reconfiguring the ring without any communication between controllers. A new self-healing solution has been successfully deployed using some short communication bandwidth between feeder RTUs to better manage the grading system of reclosers and to reduce the stress of the lines.

Volt-VAR control solutions

Volt-VAR optimization (VVO) consists of adjusting the voltage setting of Volt-VAR devices to meet certain objectives and criteria, such as to maintain voltage limits as contractually agreed upon with customers, to reduce system losses, to optimize demand reduction, or to achieve peak shaving. Many utilities do their planning calculations and simulations simply with power engineering software, and use these results to set up the settings of Volt-VAR devices without closed-loop real-time control.

Traditionally the real-time control of Volt-VAR devices is done by advanced functions of the distribution management system (ADMS). The VVO function computes the real-time network topology with data such as the load profiles of customers and producers, measurements of the main substations, measurement of some end-of-line points, switched capacitor banks status, and other network characteristics (line impedance, transformers rate settings).

But such powerful DMS are meant primarily for large utilities. New dedicated and pre-engineered solutions are now available to control a group of feeders where voltage excursions arise, in order to optimize the existing assets while increasing DER integration.

These solutions are a combination of software and communicating devices:

- Smart MV/LV transformers to regulate the voltage of the LV network
- Dedicated algorithms, using EOL (end of line) smart meters to adjust the on load tap changer (OLTC) settings, notify the unbalanced LV circuits, and achieve peak demand shaving or conservative voltage reduction (CVR)
- Smart capacitor banks and voltage regulators to flatten the voltage along the line

Deploying pre-engineered solutions

Where within the network to locate the feeders for upgrading is one of the first challenges.

For self-healing solutions, it consists of identifying the weak feeders or the feeders with critical customers that can be resupplied by a backup feeder.

For Volt-VAR solutions, a financial analysis of each area has to evaluate the benefits of reinforcing the network or optimizing the Volt-VAR. This may be done by experts from a solution manufacturer and the utility through analyzing the feasibility of using a single line diagram, feeder loads, network characteristics, the protection plan, and any installation issues.

The next step would be to equip a small part of the network with a field pilot project to adjust the internal process of the utility with the new system, including training staff, establishing maintenance procedures, and upgrading communication infrastructure.

A deployment of such solutions may be managed locally with a minimum of risk and with a scalable investment. Heavy remote control capabilities are not required for such a solution to run, and having such a solution running doesn't prevent setting up remote control center project.

Conclusion

Utilities today face ever higher expectations to maintain power quality and achieve greater service continuity. With the widespread integration of distributed energy resources all along the network, more Smart Grid capabilities are being introduced into MV/LV substations to meet these expectations. MV/LV substations lie at the heart of the needed evolution of the electrical distribution network. Now is the time for utilities to formalize their roadmap for MV/LV substation and grid transformation.

Smart technologies are now available to enable such a transformation affordably. However, some smart components have a greater impact on realizing smart capabilities than others. The type of electromechanical and communication architecture at substations plays a role in how much Smart Grid capability a utility can achieve. Substations with automatic transfer switching (ATS), Volt-VAR control devices, and digital communication infrastructure are better positioned to take advantage of the new Smart Grid technologies. An advanced distribution management system (ADMS) is crucial to realizing the full potential of a Smart Grid. An important subject to address is integrating and managing all these connected smart objects within the utility's IT systems for greater security.

Industrial specialists in power equipment and associated IT applications can help utilities identify the most appropriate solutions and advise them on the most suitable and safest deployment process. Pre-engineered solutions offer the benefit of commission time savings, reduce the number of voltage outages during installation, and are flexible enough to accommodate future network development.



About the authors

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Laurent Guise graduated from the Ecole Supérieure d'Electricité (ESE SUPELEC Engineering school) in 1981 has been working for Schneider Electric in electrical network protection, monitoring and control systems for more than 20 years. Within Schneider-Electric, Laurent has been awarded as Senior Expert in Smart Grids and IEC 61850. He is leading, at the corporate level, the definition, co-ordination, and implementation of the Smart Grids standardization policy. Laurent is the convenor of IEC TC 57 WG17 in charge of feeder automation based on the leading IEC 61850 standard. He also leads the group in charge of the IEC roadmap within the IEC Smart Energy System Committee 1. At the European level within the CEN-CENELEC-ETSI Smart Grid Co-ordination Group, he acted as the convenor of the "Smart Grid - set of standards" group, in charge of delivering one of the packages expected from the M/490 mandate issued by the European Commission.