How Utility Electrical Distribution Networks can Save Energy in the Smart Grid Era

by Michel Clemence, Renzo Coccioni, and Alain Glatigny

Executive summary

Annual electricity distribution losses average 4% in the European Union. These losses represent 7 billion Euros in annual waste. New regulations are forcing electrical distributors to enhance efficiency across their networks. Network operators are also challenged to integrate alternative energy generation and electric vehicles into their grids. This paper offers a strategy for leveraging smart grid tools that will help meet and exceed regulatory efficiency targets.

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Introduction

Efficiency of electrical distribution is rarely planned or managed by utilities. The unfortunate result is that most utilities waste substantial amounts of electricity. In fact, annual electricity transmission and distribution losses average 6% in the European Union.[1a,b] Assuming 2% for transmission and 4% for distribution losses, that represents 7 billion Euros in energy wasted every year in distribution. This number includes losses in the medium and low voltage lines and in primary and secondary substations.

As a result of recently announced government mandates, Distribution System Operators (DSOs) will need to improve the efficiency (lower the loss rates) of their electrical distribution networks by 1.5 % each year. In addition, they are tasked with finding new ways to integrate smart grid drivers such as electric vehicle charging stations and alternative energy generation (wind, solar) at consumer locations.

Today it is both possible and prudent to plan, measure, and improve transmission and distribution efficiency. Improvements can reduce operations cost by enabling the installation of equipment and software that communicates and integrates throughout the distribution path.

This paper explains how electrical distribution efficiency can be modernized to leverage the new promise of the “smart grid” while reducing distribution-related losses and associated costs (see **Figure 1**)[2]. Ramifications of the European Union’s Energy Efficiency Directive are discussed, and best practices for deploying energy efficiency solutions are reviewed.

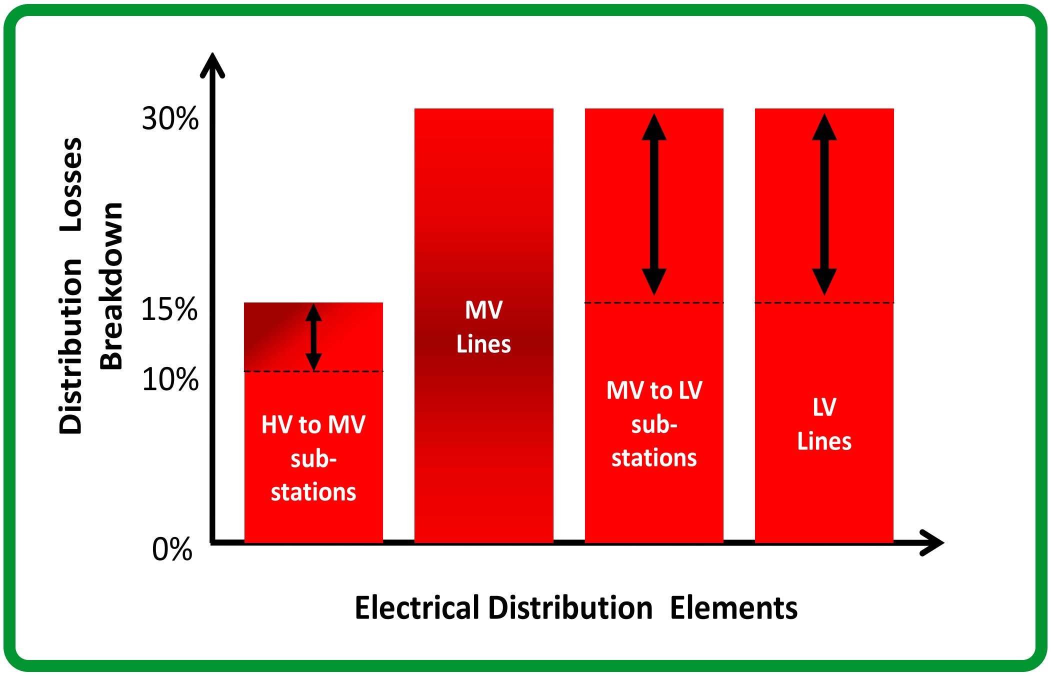

Figure 1
Distribution losses vary depending upon network configuration.

Some terminology

In the domain of electrical efficiency, it is always helpful to define common terms so that confusion is avoided when concepts and best practices are discussed. Below are a few terms that are utilized in this white paper and the associated definitions:

[1a]International Energy Agency (IEA Statistics © OECD/IEA, http://www.iea.org/stats/index.asp), “Energy Statistics and Balances of Non-OECD Countries and Energy Statistics of OECD Countries, and United Nations, Energy Statistics Yearbook”

[1b] Eurelectric: Power Statistics 2010, Full report, page 16

[2]Wolfram Heckmann, Lucas Hamann, Martin Braun, Heike Barth, Johannes Dasenbrock, Chenjie Ma, Thorsten Reiman, Alexander Schelder , “Detailed analysis of network losses in a million customer distribution grid with high penetration of distributed generation”, *Cired paper 1478*, June 2013

Active Energy Efficiency is the act of effecting permanent change in energy consumption reduction through measurement, monitoring, and control of energy usage. Examples of active energy efficiency include dynamic network reconfiguration and voltage optimization. (For more information on Active Energy Efficiency, see the Schneider Electric white paper entitled *"Making Permanent Savings through Active Energy Efficiency"*).

Passive Energy Efficiency is the act of reducing energy consumption by promoting measures that reduce thermal losses, and by using low consumption equipment. Examples of passive energy efficiency measures include the replacement of old transformers with lower loss amorphous distribution transformers, or the replacement of traditional lighting with low energy lighting.

Technical losses are physical losses that include load losses (copper or Joule effect) and no load losses (Corona losses, iron losses in transformers).

Non-technical losses are commercial losses which consist of delivered and consumed energy that cannot be invoiced to an end user. This category of losses can be split into fraudulent losses such as theft, or non-metered public lightning and hidden losses such as the in-house consumption of equipment in the distribution network (e.g., the power needed to cool transformers and to run control systems).

Distributed energy resources (DER) include a variety of supply-side and demand-side resources such as distributed generators (renewable or back-up), controllable (or flexible) loads used for demand-response, energy storage (electrical or thermal) and electric vehicles (which play a dual role of both load and energy storage).

Regulatory challenges

The European Energy Efficiency Directive 2012/27/EU, as it applies to Distribution System Operators, can be summarized as follows:

- Member states will enforce energy efficiency obligation target savings of 1.5% each year for the time period ranging from January 1, 2014 through to December 31, 2020 (Article 7).
- Network tariffs will reflect network cost-savings. These savings will be achieved through both demand-side and demand-response measures and also through distributed generation. This will include savings from lowering the cost of delivery of electricity or gas through investments in the distribution network or from network operational process improvements (Article15).
- Concrete electrical efficiency measures and investments for improvements in network infrastructure will need to be identified by June 30, 2015 (Article 15).
- Tariffs will be set at a rate that will encourage suppliers to improve consumer participation in system efficiency, including demand-response practices (Article 15).

The following sections provide examples of best practices that can help Distribution System Operators cut costs and accommodate the above regulations.

Active energy strategies for loss control

Issue 1: Technical losses in MV lines

In Europe networks are configured in open loops and controlled in order to be able to isolate a fault and restore power (see **Figure 2**). The normal open points of the loops are strategically located to maximize the quality of service, i.e., low interruption duration (SAIDI) and low interruption frequency (SAIFI). However this strategy does not minimise losses.

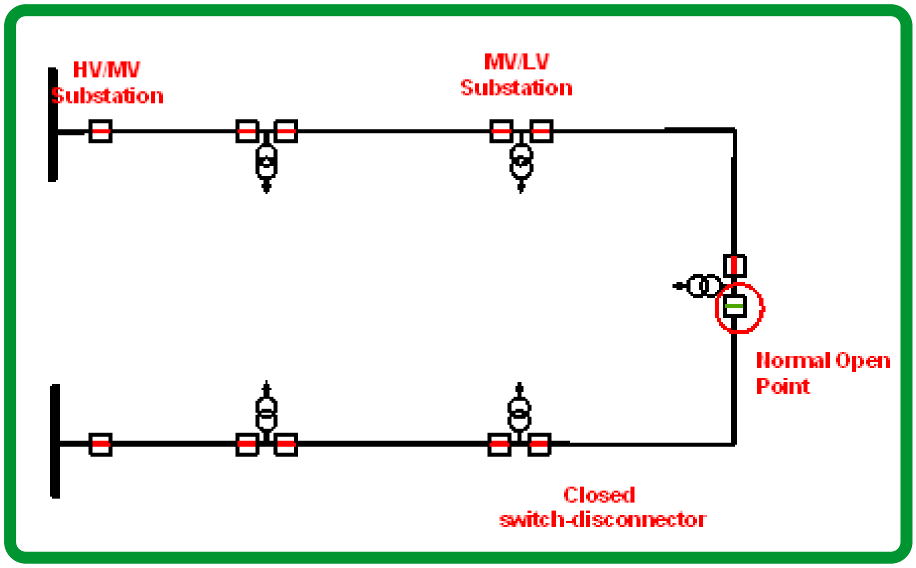

Figure 2
Diagram of a network configured in open loops and controlled in order to isolate a fault and restore power

Strategy: Advanced Distribution Management Systems

Systems built to estimate losses, like Advanced Distribution Management Systems (ADMS), need a real-time network topology, network measurements, load profiles at MV and LV substations, and customer consumption information in order to determine the optimal location of normal open points. In this environment, when the system operator plans to open or close a switch-disconnector, the ADMS simulates the impact on reliability of supply, losses, and voltage management. Algorithms calculate optimum configurations on an hourly, monthly, seasonal, or yearly basis according to provided load curves, weather forecast, real-time data coming from sensors, smart meters, and number of switch operations (see **Figure 3**).

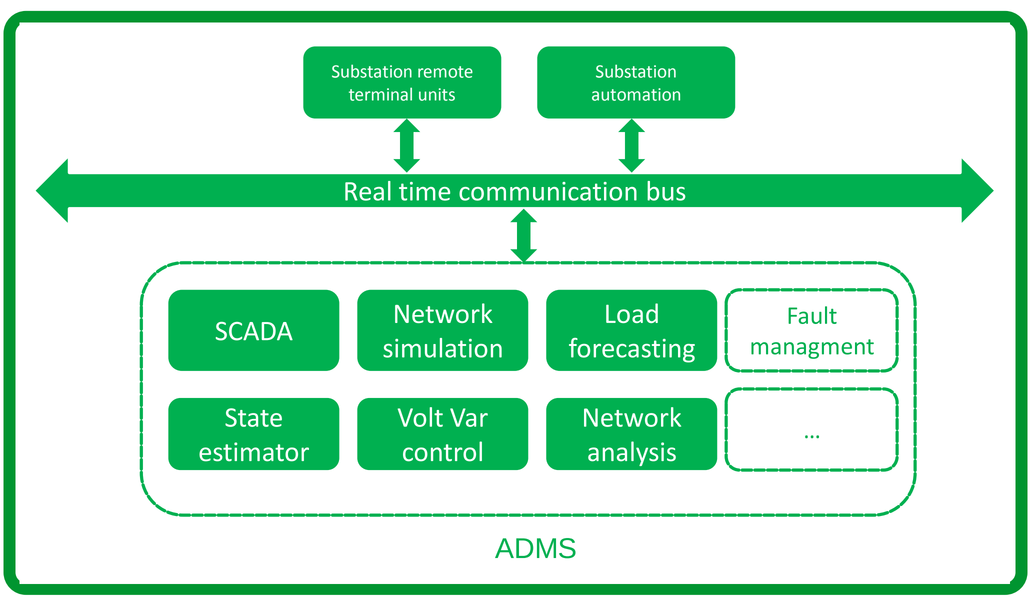

Figure 3
Simulation and testing is an effective method for reducing network energy losses

Optimal locations of normal open points in a distribution grid (power flow) depend on the actual power demand in the grid (consumption). Power demand fluctuates throughout any given day and will also change with the different seasons. These load changes impact the optimal locations of normal open points. It is therefore necessary to use a grid reconfiguration application for testing multiple grid states and to deploy a solution capable of identifying the optimal locations of normal open switches. The proper radial distribution grid configuration will be achieved in accordance with pre-selected criteria and objectives.

Deployment of such a system can help minimize losses, minimize load unbalance in HV / MV sub-station transformers and feeders, unload overloaded segments of a network, improve voltage quality and achieve an optimal voltage profile. However, the system can also be constrained by an infrastructure that limits the feasibility of switching operations and with infrastructure voltage and loading limits.

Field pilot projects of such systems have yielded some interesting results:

- Losses may be reduced up to 40% in case of an hourly reconfiguration (However, this is not realistic in terms of the number of operations. Switch-disconnector equipment is designed to respond to actual needs, such as 1.000 operations per lifetime of the device. Hourly reconfiguration would require 200.000 operations during the lifetime of the device.)
- Losses can be reduced 20% on a weekly reconfiguration basis (i.e., 50 times a year)
- Losses can be reduced to 10% on a seasonal reconfiguration basis (i.e., 4 times a year)
- Losses can be reduce to 4% in case of yearly reconfiguration

Issue 2: Impact of DER on voltage management

"As a result of the massive injection of Distributed Energy Resources (DER) requirements onto the grid, voltage management now presents DSO's with a major challenge."

One of the main responsibilities of utilities around the world is to maintain voltage limits as agreed to via contract with their customers (i.e., within +/- 10% of agreed to target). Voltage control is traditionally performed by transformers, using on load tap changers and capacitor banks that inject reactive power into the grid at the HV / MV sub-station level. The Distribution System Operator (DSO) fixes a setpoint and prepares scenarios and ranges based on seasonal load curves, for example.

As a result of the massive injection of Distributed Energy Resources (DER) requirements onto the grid, voltage management now presents DSO's with a major challenge. They now have to manage situations where voltage may be rising on one part of their grid while decreasing on another part. Thus, DSOs are deploying sensors to monitor the voltage all along feeders, new actuators that are able to regulate the voltage at different levels, and centralised or distributed intelligence to manage the macro voltage control.

Strategy: Fine tuned voltage control infrastructure

The monitoring of MV equipment in older sub-stations is costly as it requires complex, intrusive methods. Thus, the ability to acquire accurate, "real time" voltage measurements implies the deployment of new solutions and sensors to minimize long term global costs.

A number of new solutions can be deployed to address this challenge. New capacitive or resistive voltage divisors can be inserted in cable connections at the transformer or Ring Main Unit (RMU) level. Another option is to utilize "virtual sensors" capable of estimating or modeling the MV voltage based on other data that is easier and cheaper to measure. For instance MV voltage may be estimated from LV through distribution transformers or from load currents through lines impedance modeling. Depending on the level of accuracy required, sensor and installation costs can be drastically reduced.

Actuators, which are most often installed at the HV / MV substation level (on load tap changers within HV / MV transformers, capacitor banks and voltage regulators), can also be installed along MV lines or even further downstream. These new actuators are installed in smart transformers with up to 9 taps. The transformers can use MV voltage to increase or decrease the LV voltage. They are actuated by contactors with an operation durability of more than 1 million operations. No maintenance is required. Reactive energy injectors can also be utilized at the distributed generation (DG) level through insertion of dedicated devices or by using DG controllable inverters.

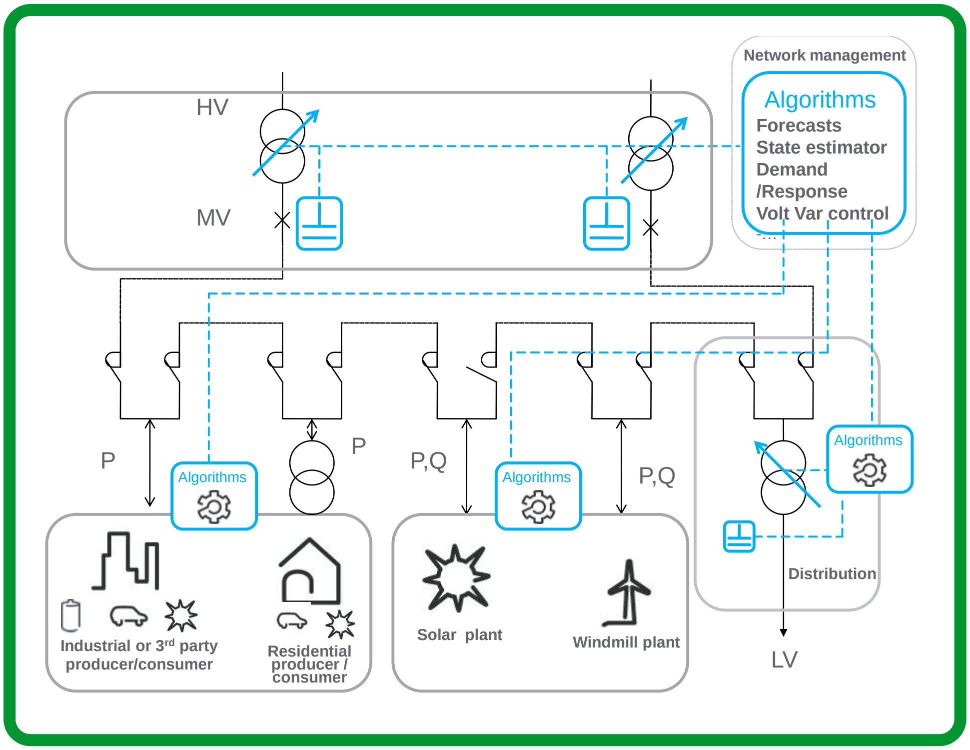

Figure 4
Voltage control aided by algorithms can help manage changes being brought about by increased presence of distributed energy resources (DER)

In the above two cases, the actuators must be managed together by new algorithms installed locally in primary or secondary substations and / or centralized in the ADMS at the control centre level (see **Figure 4**). This downstream voltage regulation must be coordinated with the legacy regulation at HV / MV sub-stations through the ADMS system.

This fine tuned voltage control infrastructure designed for DER integration can also be used to minimise technical losses. On a heavily-loaded network it can be used to operate at maximum voltage to reduce current flow at equivalent power and therefore reduce Joules losses along cables and transformers. Or it can be operated at minimum voltage on a lightly loaded network to minimize iron losses in transformers. It can also be used to minimize load peaks thereby reducing the need to use costly, high carbon footprint energy resources.

These voltage management solutions have been tested in several pilot projects in Europe. DER integration on distribution networks can result in:

- Drastic reduction of PV disconnection
- Technical losses reduction in MV lines
- Reduction of load peak

Issue 3: Technical losses in LV lines

Technical losses on MV networks represent about 3% of the distributed energy. Joules losses represent 70% of these losses[3] (but this is dependent upon the load rating of the network).

[3] Dr. Georgios Papaefthymiou, Christina Beestermöller, Ann Gardiner, "Ecofys Incentives to improve energy efficiency in EU Grids", 15 April 2013

More losses occur in the LV network. The LV ends of distribution networks are often heavily unbalanced between transformers (transformer to transformer), between LV feeders within a transformer, and between the three phases of one given transformer.

These imbalances cause joules losses in wires and transformers due to higher current level on the more loaded part of the network and to current flow in neutral wires. These losses are estimated to be between 200 and 1.000 Euros per sub-station per year.

Strategy: Detailed analysis of MV / LV level performance data

The daily load, voltage, power factor, and the temperature profiles of the substation and feeders are examples of data that can be gathered by the monitoring system. A chronological overview of events can be determined, such as the voltage duration curve, load duration curve per feeder, vector diagram for the diagnosis of unbalances per feeder and other values. These data points can then be formatted into customizable dashboards. In order to reduce the data volume that is transmitted from sub-station to the distribution management system (DMS), the curves can be calculated by local remote terminal unit (RTU). This practice helps to avoid communication congestion (see **Figure 5**).

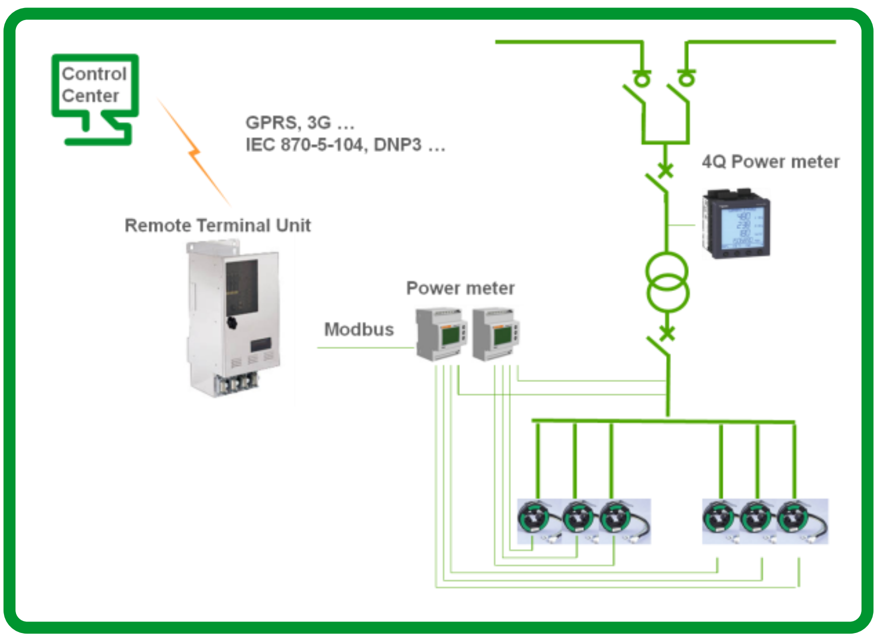

Figure 5
Data gathered from remote terminal units (RTU) can feed dashboards visible from the control center or from other remote locations.

LV feeders are equipped with energy meters connected to the RTU in the sub-station. 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 is performed by repartition units installed along the network that switch a targeted customer from one phase to another.

This particular architecture allows the network to accommodate more DER since it addresses the issues of load imbalance and helps to reduce energy loss. The switch from one phase to another can be either regularly scheduled (like once a year) or can be addressed on an ad-hoc, case-by-case basis. Benefits of deployment include an estimated cost reduction fueled by reduced joule losses in cables of 200 to 800 Euros per year, and an improvement of sub-station power output of up to 30%.

Issue 4: Non technical loss identification

Schneider Electric estimates that 90% of non-technical losses occur in LV networks. Losses are assumed to range between 1.000 to 10.000 Euros per MV / LV substation per year in European countries. Therefore LV networks are a top priority in terms of loss reduction. A first step in assessing the situation is to begin monitoring in order to determine how much loss is being incurred. In the past, LV networks were rarely monitored because, due to the high number of points to equip, monitoring was costly. Now, new approaches, architectures, and technologies allow for affordable and more precise monitoring.

Strategy: Smart metering deployment

Locating the sources of losses within the network is one of the first challenges. One solution for monitoring LV networks is to utilize smart energy meters as additional sensors to supply data regarding the energy performance of the network. Under this scenario, the first step would be to determine the proper location within the network of each of these meters. The next step would be to then equip each LV feeder with a meter. Care would have to be taken to install these meters without any outages to customers. It takes in the vicinity one hour per substation to install the energy management meters.

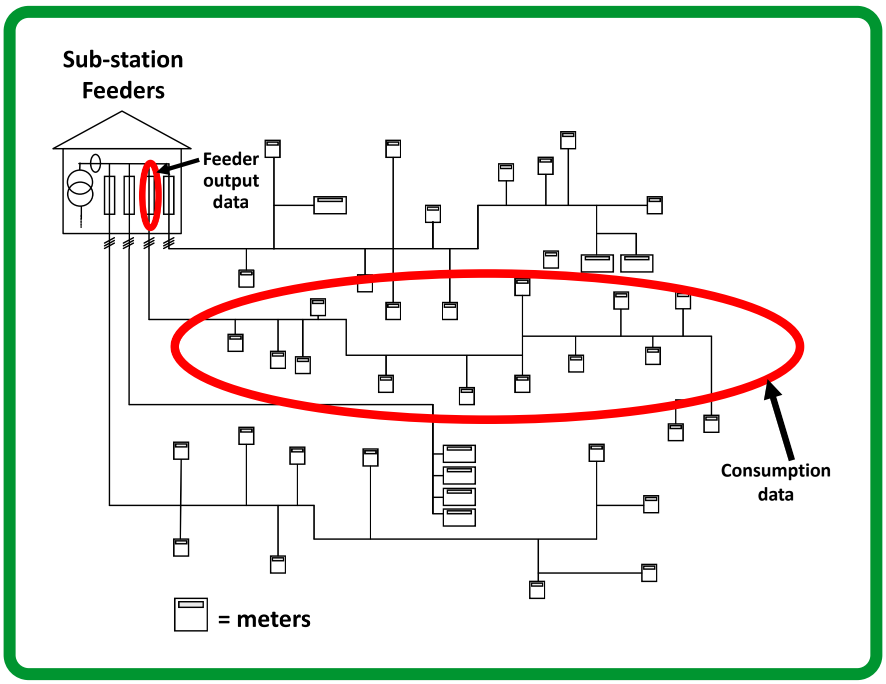

Figure 6
In this example, energy performance is determined by comparing aggregated energy consumption data from meters to energy output data from the LV feeders.

An additional step would be to compare the energy measured on the LV feeder with the sum of energies invoiced by the smart meters located across this same particular feeder network (see **Figure 6**). This action locates and quantifies losses, which then enables network operators to implement energy efficiency improvements. A variety of options exist for monitoring the system:

- At the local substation (S/S) level between the metering data concentrator (AMM) and the S/S Remote Terminal Unit (RTU)
- At the regional control centre level between Distribution Management System (DMS) and Metering Data Management (MDM)
- Via the cloud as third party service

Schneider Electric field experience has shown that utilities who implement this approach for locating and quantifying losses have been able to detect significant losses. In one LV network, for example, non-technical losses were located and identified among a pool of 5 to 15 end users and a loss as small as 100 Watts (the power of one light bulb) within a 630 kVA MV / LV substation was detected. This demonstrates the level of technical precision which is possible for both accurate location and measurement of energy losses.

In addition to loss detection, the above smart metering approach also provides faster detection and location of outages on LV networks, which leads to an improved reliability of supply. Neutral connection degradation can also be detected via voltage imbalances and this can help to prevent neutral cut out. In fact, the monitoring of transformer and neutral wire loads as well as load balancing across the network improves the quality of sub-station asset management. For more information regarding asset management of utility equipment see the Schneider Electric white paper *"Impact of Data Modeling on Asset Performance Management in Electrical Utility Environments".*

Passive energy loss control strategies

The previous sections of this paper highlight active energy efficiency strategies (energy consumption reductions resulting from software and network-related information and data gathering /aggregation procedures). The following sections refer to passive energy efficiency strategies (which focus more on hardware infrastructure upgrades).

Issue: Inefficient transformers

Transformer losses in the EU electrical network are estimated to be in the range of 70 to 100 TWh at the current load factors[4]. Distribution and power transformers represent around 5 million units. After power lines, distribution transformers have the second highest potential for energy efficiency improvement[5].

Strategy: Cut costs, losses with transformer technology upgrades

If we compare both transformers and overhead lines and cables, transformers are relatively easy to replace. In addition, modern transformer technology is capable of reducing transformer losses considerably.

Within the realm of transformers two types of losses exist: iron and copper losses. Iron losses are independent of the load and are called "no load losses". Copper losses are dependent of the load and are called "load losses".

"No load" or "fixed" losses are present as soon as the transformer is energised. "Load losses" vary according to the load on the transformer. Distribution and power transformers run 24 hours a day, therefore their energy efficiency can be impacted by reductions in both "no load losses" and "load losses".

For utilities, it may be more advantageous to reduce iron losses than copper losses, since the transformers are energized 8760 hours a year. These transformers typically do not supply load during this entire period and when they do supply load, it is never at the maximum load capacity. On the other hand it may be advantageous for industrial applications to reduce the "load losses", as these transformers are operated mainly at high load factor.

Table 1 compares traditional / conventional transformers to new generation transformers (amorphous technology). The data concludes that loss reduction can be realised through

[4] T&D Europe position paper on "Working documents on a possible Commission Regulation implementing directive 2009/125/EC with regards to small, distribution and power transformers", 6.11.2012, page 3

[5] T&D Europe position paper on Study for preparing the first Working Plan of the EcoDesign Directive Report for tender No.: ENTR/06/026, published on Nov. 22nd, March 6 2008, page 2

upgrades to the newer technology. For example, new GOES transformers have 30% less "no load loss" compared to conventional GOES transformers. Even more loss reduction can be achieved with the amorphous technology (which can reduce loss by a factor of 2).

A0, B0 C0, D0, E0 no load loss categories are defined in EN 50464, "European standardisation for transformer losses reduction". In **Table 1**, comparisons are made among conventional GOES, new GOES, and Amorphous transformers in the A0 category.

Table 1
Loss comparisons of conventional, New GOES, and amorphous transformers

Rated power	Technology	No load losses level	Load losses level	No load losses (W)	No load losses reduction
400kVA/Oil immersed	Conventional GOES	A0	Ck: 4600W	430	0%
400kVA/Oil immersed	New GOES	A0+	Ck: 4600W	300	30%
400kVA/Oil immersed	Amorphous	A0++	Ck: 4600W	< 200 (160)	63%

Some manufacturers have successfully tested a complete range of amorphous transformers from 100kVA up to 1600kVA in oil immersed. Several transformers have been installed in France, Germany, and Belgium for more than one year with positive results. In order to assess transformer efficiency it is important to capitalize the losses. The financial value of losses generated during the transformer lifetime represents a significant portion of the investment.

Table 2
Cost comparisons of conventional and amorphous transformers

Rated power (kVA)	No load loss level & Value (W)	Load loss level & Value (W)	Efficiency (n)	Purchasing cost (W)	No load loss cost (€/W)	Load loss cost (€/W)	Total investment (€)
400kVA/Oil immersed/ Conventional GOES	C0:610W	Ck: 4600W	98.71	7250	8	1	16730
400kVA/Oil immersed/ Amorphous	A0++: 200W	Ck: 4600W	98.81	10125	8	1	16325

Utilities in the European Union add the value of losses generated during the lifetime of the equipment to the purchasing cost. The financial value of losses is calculated by multiplying the amount of losses in (W) declared by the manufacturer, by the value indicated by the purchaser (expressed in €/W). The calculation in **Table 2** shows that the total investment cost of an amorphous transformer being lower than the conventional transformer, despite the fact that the purchasing cost for the amorphous transformer is higher.

Conclusion

Many distribution networks are poorly or partially instrumented, especially downstream in the areas of secondary substations. As a result of the massive introduction of local production, these networks are becoming more difficult to manage. More accurate and highly networked sensors, actuators, and management systems will be required to achieve European Union targets of new renewable energy sources deployment.

Those interested in initiating a migration plan for the development of a more efficient distribution network should consider the following steps:

- Within the next 3 months, identify areas where waste can occur: primary substations, MV feeders, secondary substations. Consider parameters such as density of population, power of existing and forecasted DER, strategy around smart metering, and existing communication options.
- Within the next year, install sensors and applications that can accurately assess the magnitude of the efficiency losses. Begin to identify areas of improvement.
- Within the next two years, implement pilot project to demonstrate feasibility, quantify the gains, and estimate the deployment costs.
- Within the next 10 years plan and implement the staged rollout.

Although market realities may increase short term capital costs, long term advantages will include lower operating costs, reduced energy waste, and a more integrated and flexible network.

About the authors

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