Chapter 10

Planning Tools for the Integration of Renewable Energy Sources Into Low- and Medium-Voltage Distribution Grids

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Additional information is available at the end of the chapter

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Abstract

This chapter presents two probabilistic planning tools developed for the long-term analysis of distribution networks. The first one focuses on the low-voltage (LV) level and the second one addresses the issues occurring in the medium-voltage (MV) grid. Both tools use Monte Carlo algorithms in order to simulate the distribution network, taking into account the stochastic nature of the loading parameters at its nodes. Section 1 introduces the probabilistic framework that focuses on the analysis of LV feeders with distributed photovoltaic (PV) generation using quarter-hourly smart metering data of load and generation at each node of a feeder. This probabilistic framework is evaluated by simulating a real LV feeder in Belgium considering its actual loading parameters and components. In order to demonstrate the interest of the presented framework for the distribution system operators (DSOs), the same feeder is then simulated considering future scenarios of higher PV integration as well as the application of mitigation solutions (reactive power control, P/V droop control thanks to a local management of PV inverters, etc.) to actual LV network operational issues arising from the integration of distributed PV generation. Section 2 introduces the second planning tool designed to help the DSO, making the best investment for alleviating the MV-network stressed conditions. Practically, this tool aims at finding the optimal positioning and sizing of the devices designed to improve the operation of the distribution grid. Then a centralized control of these facilities is implemented in order to assess the effectiveness of the proposed approach. The simulation is carried out under various load and generation profiles, while the evaluation criteria of the methodology are the probabilities of voltage violation, the presence of congestions and the total line losses.

Keywords: Design of experiments, Dispersed generation, Distribution systems, Monte Carlo simulation, Smart metering

1. Introduction

Following the Kyoto Protocol and in the context of a liberalized energy market, decentralized generation, often based on renewable energy sources, is emerging in medium- voltage (MV) and low-voltage (LV) distribution grids. Those networks are becoming more and more active with power flows and voltage profiles influenced by both generation and consumption. In the future, given the '20–20–20' objectives of the European Union and the more ambitious objectives in Wallonia (Belgian region), the expected penetration of decentralized generation in distribution grids could lead to a critical behaviour of the system that has not been initially designed and sized to face power injections coming from dispersed units. This major paradigm shift in distribution grids is even strengthened by the numerous financial incentives granted to the renewable generation for ensuring their profitability. Indeed, this financial support has progressively driven down the electricity prices on power markets to the point of making the conventional generation less profitable, which already led to the closing or the mothballing of more than 50 GW of gas plants in Europe during the last few years [1].

Consequently, in the MV grids, the main problems due to a massive integration of distributed generation (mainly wind parks) are due to local congestions of power lines and/or to over-voltages in the neighbourhood of the dispersed generation units. Concerning the LV grids, the major problem that can be met by the distribution system operators (DSOs) comes from overvoltage in the neighbourhood of photovoltaic (PV) installations. Such a situation could happen during periods of low consumption and high generation of those decentralized units, especially on long power lines. Furthermore, reverse power flows going up the line towards the MV/LV transformer can then degrade the network stability.

The DSO is responsible for the security of its system and power quality. It is therefore important to develop planning tools that ensure secure and reliable operating conditions within the whole grid. Moreover, it is also essential for DSOs to avoid early damages of the network equipment as well as to optimally manage the investment decisions and the maintenance plans. However, as the intermittent generation is often difficult to predict due to its stochastic behaviour, the planning studies become more complex to carry out. Indeed, it is now indispensable to use probabilistic approaches to model the different network components, since the traditional deterministic worst-case scenarios yield much more restrictive conclusions that can lead to overestimated reinforcements [11].

In that way, two probabilistic tools are described in this work. Both are based on Monte Carlo (MC) simulation whose general principle is to generate a large number of system states in order to provide consumption and generation patterns that are representative of the actual behaviour of all customers. However, it is important to mention that long-term analyses are focused on modelling realistic scenarios of the system evolution rather than making an accurate prediction. It is indeed utopian to expect a precise hourly model of the wind farm generation for a whole year. Practically, two different types of Monte Carlo simulation are implemented. The first one is a non-sequential simulation that generates a set of system states independent of each other. This method is combined with the design of experiments (DOE) methodology in order to proceed to an optimal positioning as well as to a pre-sizing of voltage compensation

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devices (capacitor banks, storage units, static VAR compensators (SVCs), etc.) at the MV level. The purpose is to help the DSO in optimally managing its systems with adequate investments. The first tool requires aggregated load profiles at the MV/LV interface. Those statistical profiles are typically obtained, thanks to a second tool developed for the safe integration of PV units in LV grids. The latter is implemented in a pseudo-chronological Monte Carlo environment and is based on quarter-hourly energy flows recorded by smart meters (SMs). Practically, thanks to statistical profiles established by the use of these measurements, the tool is able to compute different parameters throughout a specified period of time such as the voltage profile along the studied feeder or the distribution of the power profile at the MV/LV substation. In this chapter, in order to demonstrate its interest for DSOs and to introduce the potential of some technical solutions (reactive power control, P/V droop control thanks to a local management of PV inverters, etc.) to alleviate the influence of PV generation in LV grids, this tool will be applied to a practical case study.

This chapter is thus divided into two main parts, each one focusing on one of both the above-mentioned probabilistic tools. Section 1 concerns the description of the planning at the LV level. More particularly, the extraction of the energy flow data coming from SM installed in the LV-Belgian distribution grid as well as their use in the Monte Carlo procedure is presented. Then, the potential of several power- or voltage-control strategies is evaluated for an existing LV area subjected to abnormal operating conditions. Section 2 relates to the planning tool studying investment plans that may have to be taken in critical areas of the MV grid.

2. Probabilistic analysis of low-voltage networks

The techno-economic analysis of LV feeders is typically governed by a set of basic rules that define voltage, voltage unbalance and current limits. According to these rules, which are most often precisely determined by regional or national standards, voltage along the feeder should fall within a defined band during a minimum percentage of time. As far as the voltage unbalance is concerned, an upper limit should also be respected during a minimum percentage of time. The limits that concern the value of the current do not often apply in LV feeders apart from urban networks with high load density.

When adding distributed photovoltaic generation to an LV feeder, voltage profile is the parameter that is mostly affected. Indeed, during periods of high PV injection and low consumption, reverse power flows towards the head of the feeder can occur. These reverse power flows result in a voltage rise at the end of the feeder. According to the European EN 50160 standard [2] and its national implementations (i.e. the voltage cannot vary more than 10% around its nominal value), if the upper limit of the root mean square (rms) voltage is exceeded at a certain PV node, the unit must be temporarily cut off [2], [3]. This causes a loss of generated PV power, which means a loss of income for the PV owner. Moreover, these frequent cut-offs, combined with the randomly changing loading profile along LV feeders, affect the distributed power quality and accelerate the degradation of network components. The operational cost of the network, currently assigned to the DSO, is therefore increased due to the accelerated ageing of its components.

The development of technical solutions to such problems has, from the DSO point of view, a threefold objective, namely the security level of the network, the increase of PV-hosting capacity of the feeder and, naturally, the investment cost. For a given PV-hosting capacity, the optimal design of a technical solution could be roughly determined by a graph similar to Figure 1. On the other hand, for a selected security level, the optimal hosting capacity in a feeder could be based on a graph similar to Figure 2.

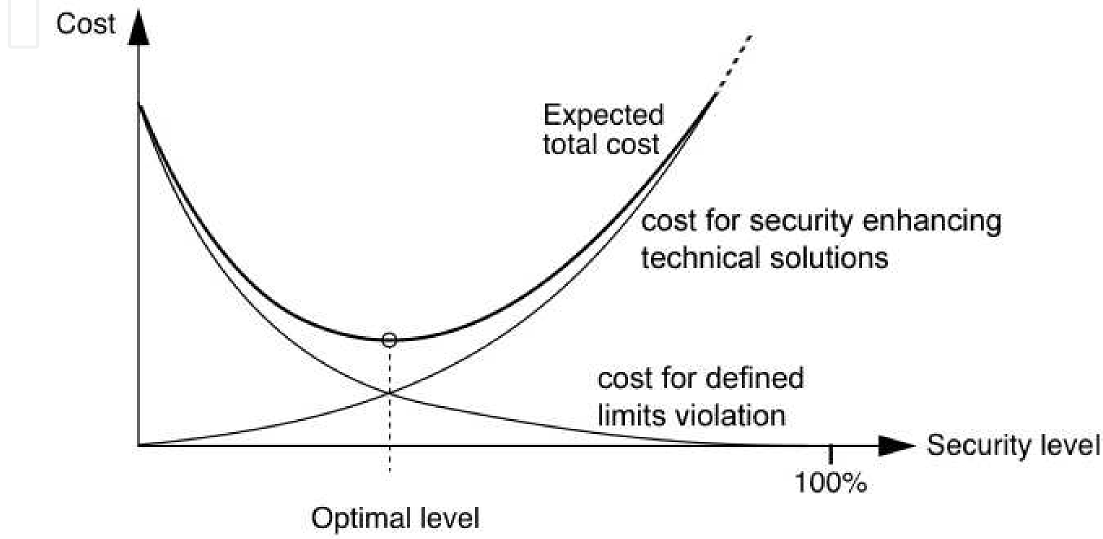

Figure 1. Schematic of cost-security.

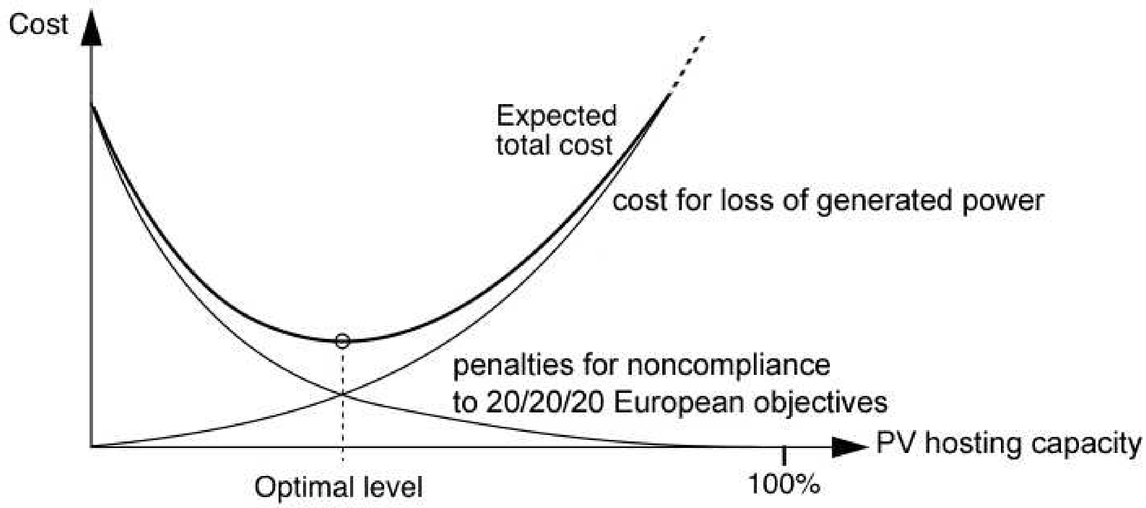

Figure 2. Schematic of cost-hosting capacity.

For designing adequate technical solutions to current problems while increasing the PV-hosting capacity, the DSO needs to locate the critical points and quantify the voltage magnitude and unbalance violation risk in every LV feeder. Currently, the DSO evaluates the LV network operation using deterministic analysis tools: the energy exchanges at the nodes of a network with distributed PV generation are determined based on worst-case scenario. For example, as far as the evaluation of overvoltage risk is concerned, the DSO makes its calculations considering the scenario of the highest expected PV injection and the lowest consumption load along each specific feeder. Although worst-case approach is safe for the protection (100% security level) of the electrical system, it focuses on rare extreme operation states of the network instead of the most possible ones. As a result, the worst-case approach often leads to oversized and costly technical solutions that do not consider the time fluctuation of PV injection and the randomness of consumption loads. Taking this time dependence into account will allow a refined optimized design of mitigation techniques in terms of efficiency and investment cost, closer to the optimal level that is roughly represented in Figure 1. For the above reasons, a doubt concerning the effectiveness of the deterministic worst-case models has recently arisen in literature [4], [5].

In order to take into account the time variation of the PV injection and the random behaviour of the loads and PV installations along an LV feeder, probabilistic analyses were introduced in late research works [6, 9]. These methodologies are based on analytical or numerical approaches, such as the Monte Carlo simulation, aiming at simulating the uncertainty of PV injection and residential loads. Nevertheless, most of these studies propose advanced probabilistic models based on solar irradiation data for the PV panels and meteorological data for the consumption loads. Such data are rarely directly accessible to the DSO and most of them do not consider the efficiency of the PV cells. Currently, DSOs in several countries are installing smart metering devices that record voltage, current as well as active and reactive powers with a high time resolution (10 or 15 min), even for domestic customers. According to European Photovoltaic Industry Association (EPIA), large amounts of such data will be available at the horizon of 2020 [10]. The processing of these data is, nevertheless, still a challenging task that will have to be addressed.

2.1. Statistical modelling of the energy flows at LV nodes

A procedure for building statistical profiles of energy flows at LV nodes and of the voltage at the MV/LV substations is presented in references [11, 13] and will be summarized here. The data are recorded by SM devices that have been installed by the DSO in the Belgian grid but the procedure can be extended to any LV grid with such metering devices. The SM configuration of every PV customer is presented in Figure 3.

The SM1 records the total quarter-hourly (15 min) injected energy towards the network (E_{inj}) and consumed energy by the customer (E_{cons}). It is therefore the metering device that records the energy flow at the interface between the customer and the LV network. The SM2 records the total 15-min energy generated by the PV unit ($E_{\mathrm{PV,inj}}$) and consumed energy ($E_{\mathrm{PV,cons}}$) by the power electronic devices that are necessary for its connection to the network. These four values have been recorded on a 15-min basis for all PV customers over a long period (>2.5 years).

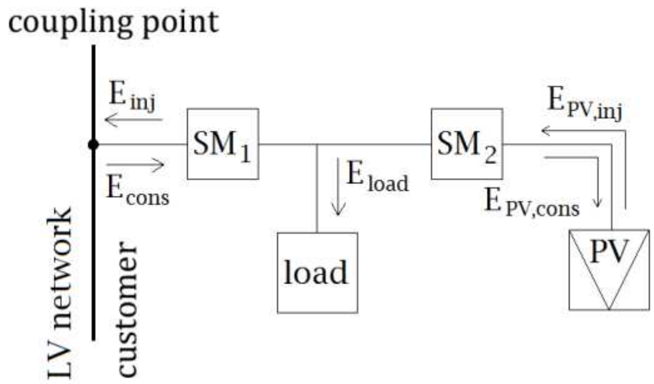

Figure 3. Smart metering configuration of every customer with PV unit, connected to the LV feeder.

For the purpose of evaluating the overvoltage risk along a feeder, the SM1 data, namely the energy flows at the coupling point of the PV customer to the network, are most preferably used. These 15-min values are therefore used for the creation of typical day profiles (TDPs) for every individual quarter of an hour in a day (96 quarters of an hour). Created independently for each node (customer), the TDPs reflect the variation of energy flow, separately for injection and consumption, for every 15-min interval in a day, during the studied period. Similar TDPs are also created to reflect the variation of the voltage at the head of the feeder, based as well on 15-min SM voltage data recorded at the LV side of the MV/LV transformer. It is worth noting that such profiles can be very easily created for various averaging time steps of SM devices. In most cases, SM devices in LV networks in Western Europe record energy flows on a 15- or 10-min time resolution.

The TDPs are then statistically transformed into 96 cumulative distribution functions (CDFs), that is, one for each quarter of an hour of the typical day, and they will be used in the framework of an MC probabilistic load flow.

2.2. Probabilistic load flow using a Monte Carlo method

The Monte Carlo simulation is a mathematical technique that allows accounting for the random behaviour of some variables within the studied system. In our case, the stochastic variables are the consumption and the generation of each customer of the LV grid during the day. The principle relies on the repeated random sampling of these variables in order to accurately simulate the system and to obtain numerical outcomes (i.e. probability of overvoltage at each node of the LV grid).

The above-mentioned CDFs are sampled under an MC framework in order to generate randomly 15-min network states. A balanced power-flow algorithm then computes the voltage profile along the feeder considering the sampled energy flow values at each node and the sampled voltage at the head of the feeder. The procedure is repeated numerous times in order to test a large amount of possible combinations. For obtaining a good convergence threshold (<0.1%) on the results, it is shown that 10,000 simulations is a good trade-off to keep acceptable computation times [11].

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However, for performing the power-flow computation, the total 15-min energy-flow values must be transformed into instantaneous power values at each node. The injected or consumed power is rarely stable during the 15-min interval, which means that the total recorded energy is very often injected or consumed in a very short (<<15 min) period of time. Indeed, it has been shown in reference [12], thanks to advanced grid analysers installed by the DSO at critical network points that the power flow at the coupling point of a grid customer is highly fluctuating within the 15-min intervals. Therefore, the peak values of injected or consumed power might be much higher than the average ones that consider a stable power flow.

In the proposed probabilistic framework, for the sake of security, these instantaneous power values are not considered equal to the average values, which would be computed by dividing the total injected or consumed energy by the respective period of time. As explained in reference [12], TDPs are also created for the time repartition of the energy flow within the 15-min intervals based on 3-min recordings of advanced grid analysers at limited critical points of the network. These TDPs are also integrated in the MC algorithm, once they have been transformed into CDFs, in order to provide the sampling frame for the time repartition factor f_i for each node i. This factor practically defines the peak injection or consumption power values.

The computed peak power values are therefore the ones considered in the power-flow algorithm. The rms voltage in this way is calculated node by node for each 15-min network state, which is therefore characterized by the following values:

$$\begin{gathered} E_{\mathrm{cons},i}, E_{\mathrm{inj},i}, f_i \text{ for nodes } i = 2:N \\ V_{\mathrm{MV/LV}} \text{ for node } i = 1 \\ P_i = \frac{E_{\mathrm{inj},i}}{f_i} \text{ for nodes } i = 2:N \end{gathered} \tag{1}$$

These 15-min values are compared to the voltage band that is imposed by national, regional or local values. In the case of Europe, such limits are imposed by the EN 50160. In this way, the overvoltage probabilities can be determined, node by node, for the studied period.

2.3. Illustration on an LV-Belgian network

The LV feeder, which is illustrated in Figure 4, makes part of the LV-Belgian distribution network. This feeder (technically described in reference [12]) is simulated with the presented probabilistic framework for every month of a typical year, considering the 15-min SM data recorded over a period of two years. In total, 16 clients are connected to the feeder, among which three are equipped with a PV installation (5 kVA at node 4, 2.65 kVA at node 12 and 5 kVA at node 13). In order to clearly demonstrate the influence of the PV generation on the voltage variation, six more PV clients have been considered at nodes 5, 6, 8, 10, 11 and 14 for this simulation. For these additional units, the same PV injection SM data as for the PV unit at node 13 were considered.

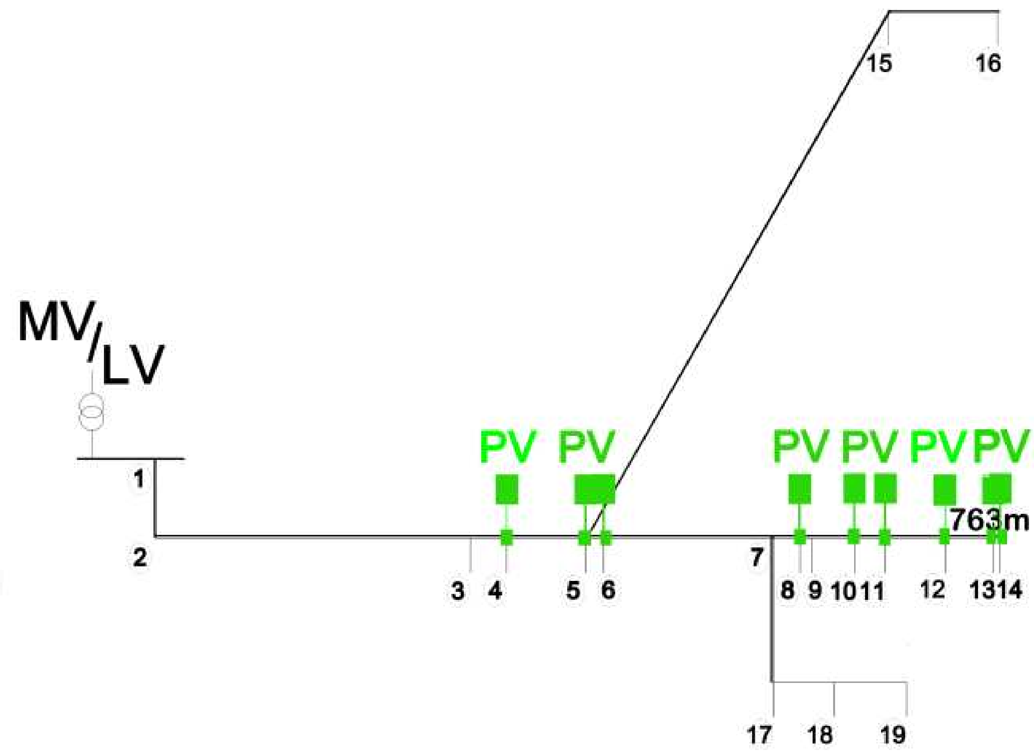

Figure 4. The simulated LV feeder.

Time variation for a given MC simulation of the voltage profile at node 14 is shown in Figure 5. Calculated with a deterministic analysis, the voltage would have been a stable worst-case value that would characterize the whole period of a day. However, based on the current analysis and the use of SM data, it is clearly shown that the voltage rises only during certain hours of the day, usually between 11:00 A.M. and 16:00 P.M.

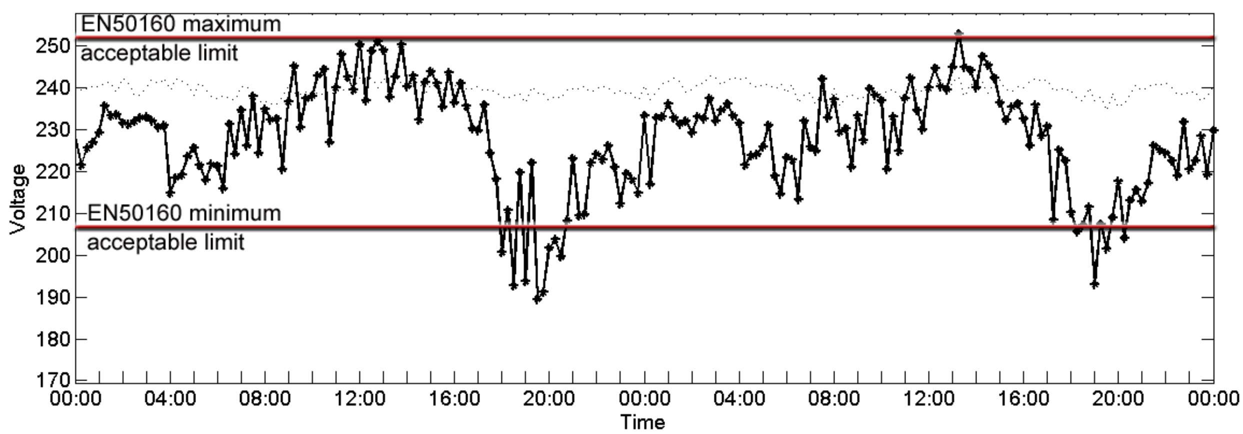

Figure 5. Voltage at PV node 14 during two typical days in April, calculated on a 15-min basis.

Thanks to the probabilistic simulation, the overvoltage risk can be defined for each node during the studied period. This risk is defined as the probability of exceeding the limit (>1.10 V_{nom})

suggested in the European standard EN 50160. According to the latter, the PV unit must be instantaneously disconnected in case the mean node rms voltage during the last 10 min exceeded the 1.10 V_{nom} limit, or in case the node rms voltage instantaneously exceeded the 1.15 V_{nom} limit. In general, these events must not take place for more than 5% of the time. Based on Figure 6, it is clear that the overvoltage risk is higher during months with high solar irradiation (June to August) or with long sunny periods (March to June). Such events are expected for hours usually characterized by low energy consumption along the feeder and high PV generation, since reverse power flows can lead to instantaneous rise of the voltage profile towards the end of the feeder.

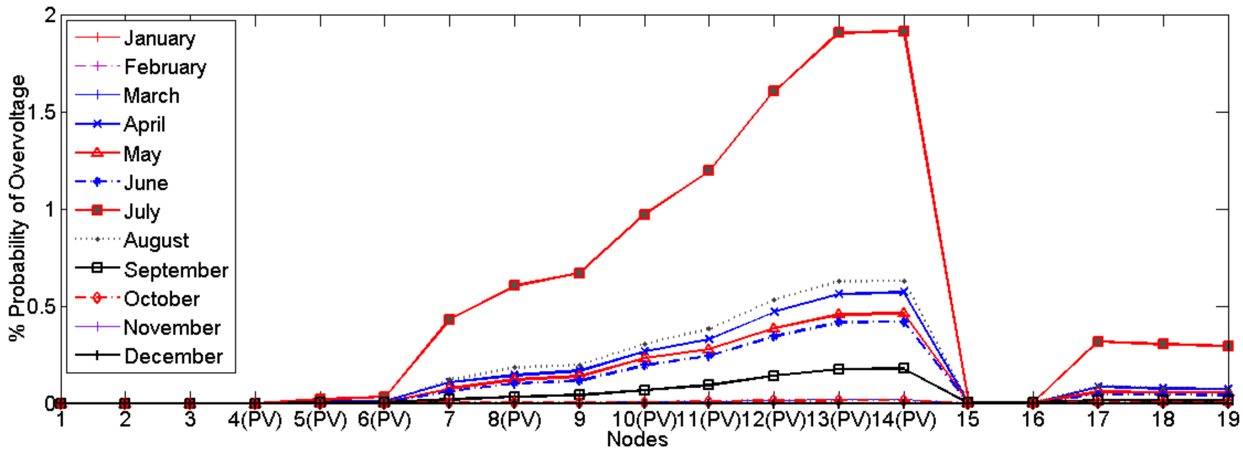

Figure 6. Overvoltage risk at the nodes of the simulated feeder for every month of a typical year.

A significant voltage drop takes place between 18:00 and 21:00 hrs, due to peak electricity demand, which increases undervoltage risk (<0.90 V_{nom}) during this period. Based on the probabilistic simulation of the same network for the period of a 'typical year', the average undervoltage risk for each node is illustrated in Figure 7. As expected, this risk rises between November and March due to higher electricity demand for heating.

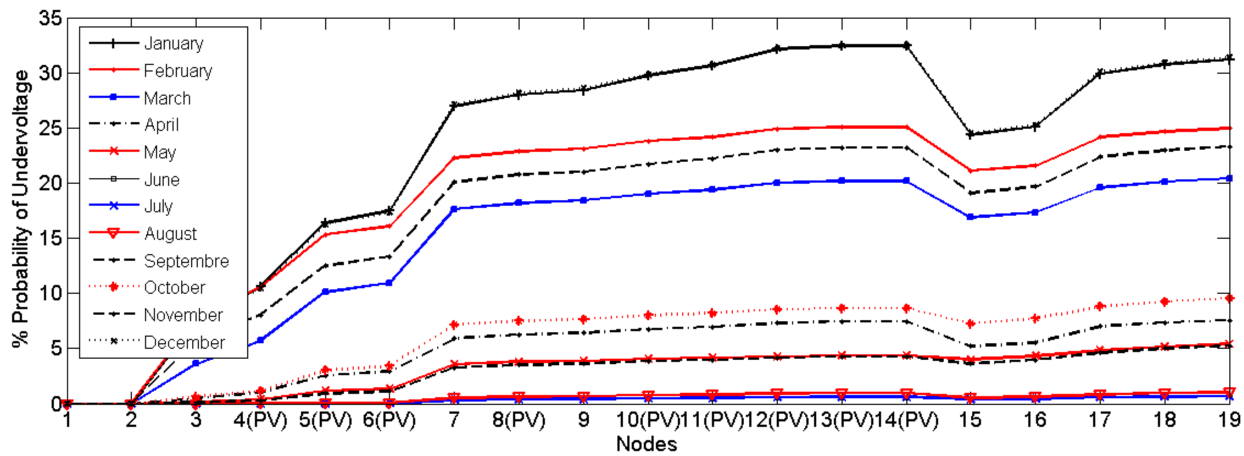

Figure 7. Undervoltage risk at the nodes of the simulated feeder for every month of a typical year.

In Figure 6, it can be seen that nodes adjacent to PV units are also affected by rapid voltage variations and oscillations (caused by the on–off control of the units), which tend to accelerate the degradation of many network components. On the other hand, it has been shown in reference [14] that the number of line congestions and the transformer load are significantly impacted with the emergence of PV generation and electric vehicle (EV)-charging devices. In this way, Figure 8 illustrates the decrease of line congestion when PV generation is included into the grid. Indeed, the power produced by these units is consumed locally by the neighbouring loads, which reduces the line power flows. Conversely, the introduction of EV-charging devices has an adverse impact on the grid. Indeed, these are powerful appliances (typically 230 V and 16 A) that significantly increase the current in different lines. Figure 9 shows the statistical distribution of power flows at the MV/LV substation. One can see that the power at the MV/LV interface decreases when generation is installed into the grid and substantially rises with the integration of EV-charging appliances. Therefore, three different scenarios are investigated in this study. Scenario 1 considers the feeder represented in Figure 4 but with no PV generation. Scenario 2 considers the same feeder with PV units at nodes 4, 5, 6, 13, 14 (rated power 5 kVA) and at node 12 (rated power 2.65 kVA), whereas scenario 3 considers also the EVs connected to the same households than those with PV panels. It should be noted that the EVs are simulated based on typical EV-charging profiles and on the statistical behaviours of current EV owners.

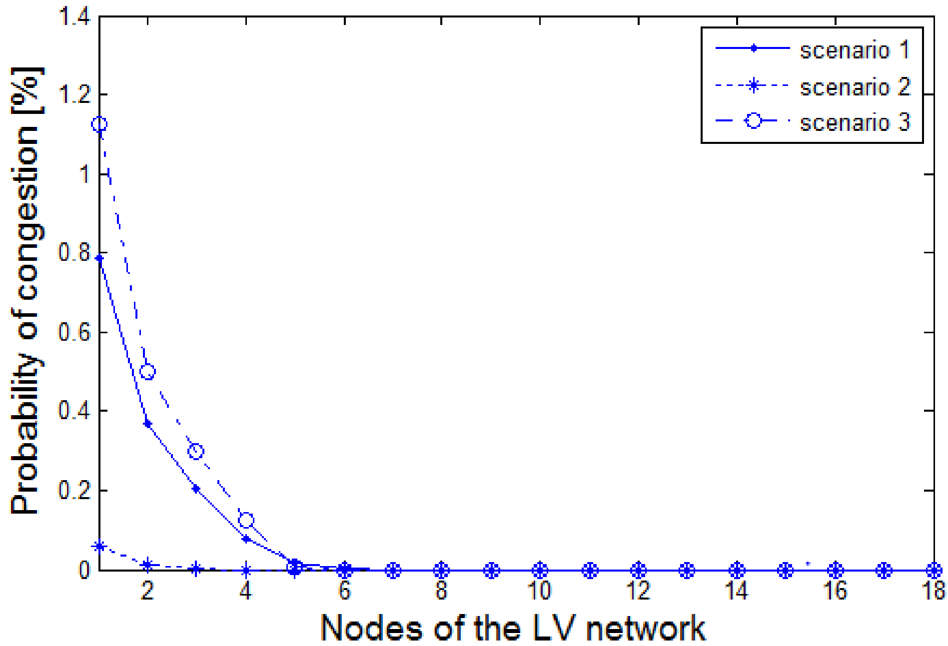

Figure 8. Probability of congestion for each line section of the first feeder with 19 nodes for the month of June.

The previous results highlight the necessity to adopt strategies aiming at limiting these important voltage and current variations. Otherwise, actions can be too restrictive for potential PV hosting capacity of the network or much less optimized in terms of efficiency and cost as roughly represented in Figures 1 and 2. Moreover, the probabilistic framework can also

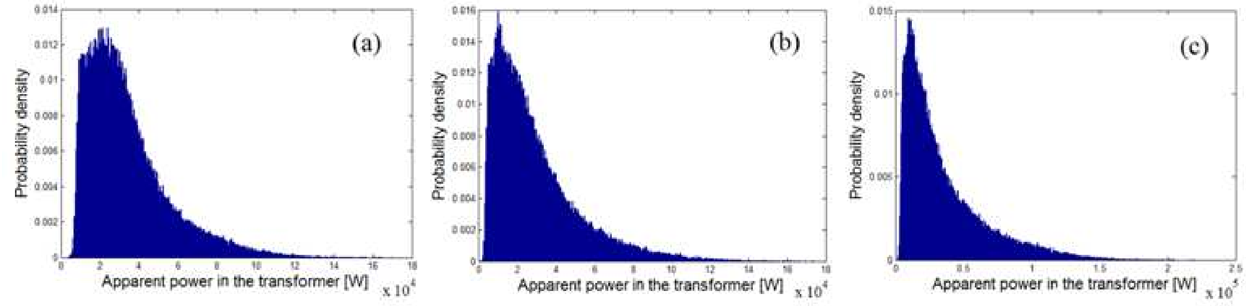

Figure 9. Yearly loading distribution at the transformer for (a) the traditional LV grid, (b) current grids with PV units (b) and (c) future grids with the introduction of EV-charging devices.

simulate future scenarios of PV integration increase, or techno-economically evaluate multiple solutions to network operational problems. It can therefore provide answers for an efficient and secure operation of LV networks, taking into account the optimal level that is represented in Figures 1 and 2.

2.4. Evaluation of the strategies for mitigating the overvoltage risk

Currently, certain DSOs evaluate the potential benefit of load-shifting strategies on mitigating overvoltage risk and increasing the PV energy capture. Incentives that promote self-consumption of the generated PV power by its producer should be designed based on the time variation of the network states. In line with this assumption, the self-consumption rate of 20 residential PV customers has been studied by using the 15-min recordings of the SM2 devices. The self-consumption ratio of each PV customer can be calculated for each quarter of an hour in a day by using both the SM1 and SM2 data and applying the following relation:

$$\text{Ratio}_t = \frac{\left(E_{\text{PV,inj},t} - E_{\text{inj},t}\right)}{E_{\text{PV,inj},t}} \text{ with } t = 1:96 \tag{2}$$

The average self-consumption ratio of three residential PV customers is shown in Figure 10 for each quarter of an hour, based on SM1 and SM2 data for the month of July. According to this diagram, the self-consumption ratio decreases during hours of peak PV injection, differently for each one of the clients. One could therefore assume a quite high potential for strategies that could shift consumption loads towards high PV injection hours. Such strategies could achieve an important mitigation of the overvoltage risk that usually increases during these hours as shown in Figure 5. The design of incentives could be therefore based on a thorough study of the self-consumption behaviour of customers connected to similar LV feeders, by using SM recordings and suitable clustering methodologies.

Apart from load management strategies, certain power or voltage control strategies are currently discussed by the DSOs for facilitating the integration of renewables in the LV network. Among them, reactive power control is a strategy that has been recently implemented

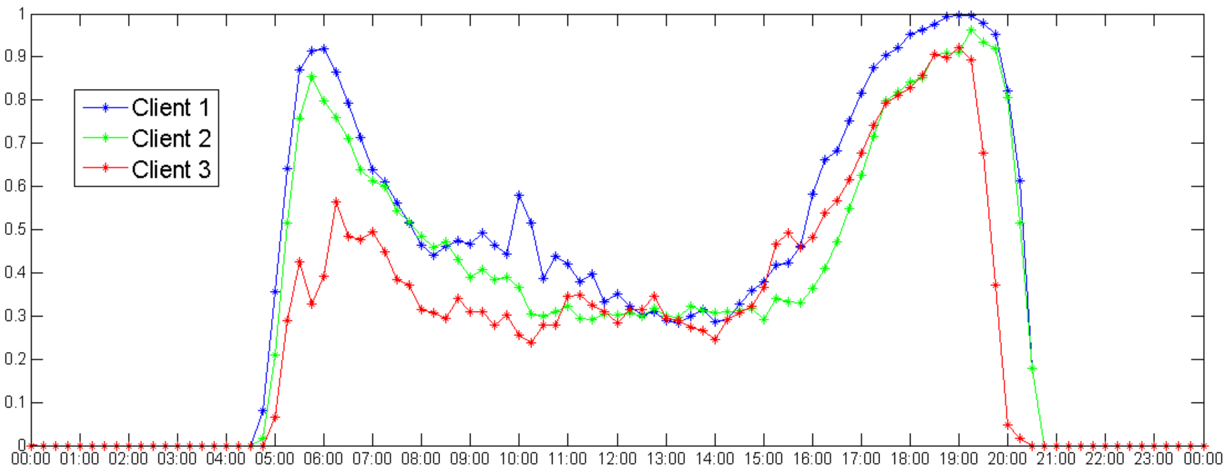

Figure 10. The quarter-hourly average self-consumption ratio of three PV residential PV customers.

in the LV networks of some European countries. In these cases, the distributed PV units have to be equipped with Q/V droop functions in order to provide voltage support as the conventional large power plants. The reactive power of the PV inverter is then adjusted, based on the local voltage, according to a $\cos(\varphi) = f(P)$ function that is defined by the respective national regulations [15].

In this study, a simpler application of this control scheme, that does not consider the actual local voltage, has been simulated in order to evaluate its benefit on the mitigation of the overvoltage risk. The purpose of this example is to illustrate the potential of this probabilistic tool in order to constitute a benchmark for evaluating and comparing voltage control solutions. In the previously presented results, the reactive power generated by PV inverters has been set equal to zero in order to minimize power losses. Turytsin et al. demonstrate that the optimal adjustment of PV inverter reactive power could reduce voltage variations. The maximum available reactive power at each PV node i is calculated as follows [16]:

$$Q_{\text{inv,max},i} = \sqrt{\left(S^2_{\text{rated},i} - P^2_{\text{inj},i}\right)} \tag{3}$$

where S_{rated} is the nominal active power (equal to the apparent power) of the PV unit at node i, whereas $P_{\text{inj},i}$ is the PV active power injection at node i for the system considered state. In order to evaluate the benefit of such a control, the same LV feeder has been simulated with the probabilistic framework, but this time considering that the reactive power of each PV inverter i is equal to 0.1 $Q_{\text{inv,max},i}$. As shown in Figure 11, the overvoltage risk for the scenario with reactive power control has decreased for the month of July.

In European countries where such a control scheme has been implemented in the LV network, the value of the power factor ($\cos(\varphi)$) cannot be lower than 0.95 for an installed power smaller than 6 kVA. Hence, such a voltage support through reactive power can often be inefficient as

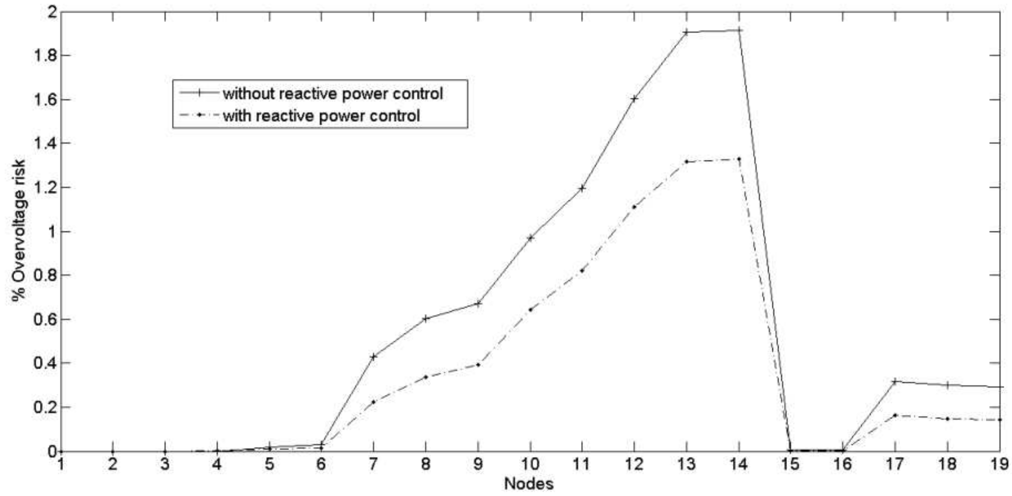

Figure 11. Reactive power control effect on the overvoltage risk for the month of July.

the network voltage is principally influenced by the active power due to the low X/R ratio of the lines [17], [18]. Large amounts of reactive power would be therefore required to influence the voltage. In this context, P/V droop controllers are more efficient and straightforward to provide voltage support in an LV network [19, 21].

Presently, the PV power injection towards the network is solely subject to the maximum power point (MPP) of the PV units. In case of voltage violation, the PV inverters passively undergo the on–off control that is required by the European or national standards, without considering the current network state. In order to address this operational issue, T. L. Vandoorn and colleagues developed a fast-acting primary control scheme based on voltage droops [22]. The droops are applied by P/V controllers requiring neither inter-unit communication nor voltage tracking for synchronization. In this study, P/V droop control is evaluated with the proposed probabilistic framework in the same LV feeder in order to analyse its benefit on the voltage level, the captured renewable energy and the on–off oscillations of the PV inverters. The evaluation considers the time variation of nodal injection and consumption and is therefore based on the analysis of multiple network states and not only the worst-case ones.

The P/V control scheme modifies the injected active power of the PV unit in function of the local voltage in order to prevent and eliminate overvoltage situations. In this way, the total cut-offs of PV units, applied in the conventional on–off control, and their subsequent effects (voltage and current transients as well as significant PV power loss) are avoided. The P/V droop controller adapts P according to the scheme in Figure 1 [22].

For the purpose of evaluating the benefit of the P/V droop control, all PV inverters were considered equipped with a P/V controller. The application of this control in the studied LV feeder, considering SM data for the month of July, demonstrated its efficiency for eliminating the overvoltage risk along the feeder [23]. In Figure 13, the voltage profile at node 14 for the droop control and for the on–off control scenario is indicatively presented for a period of two typical days of July. Generally, the voltage profile of the P/V control scenario coincides with one of the on–off scenarios apart from the three 15-min intervals of the first day and two 15-

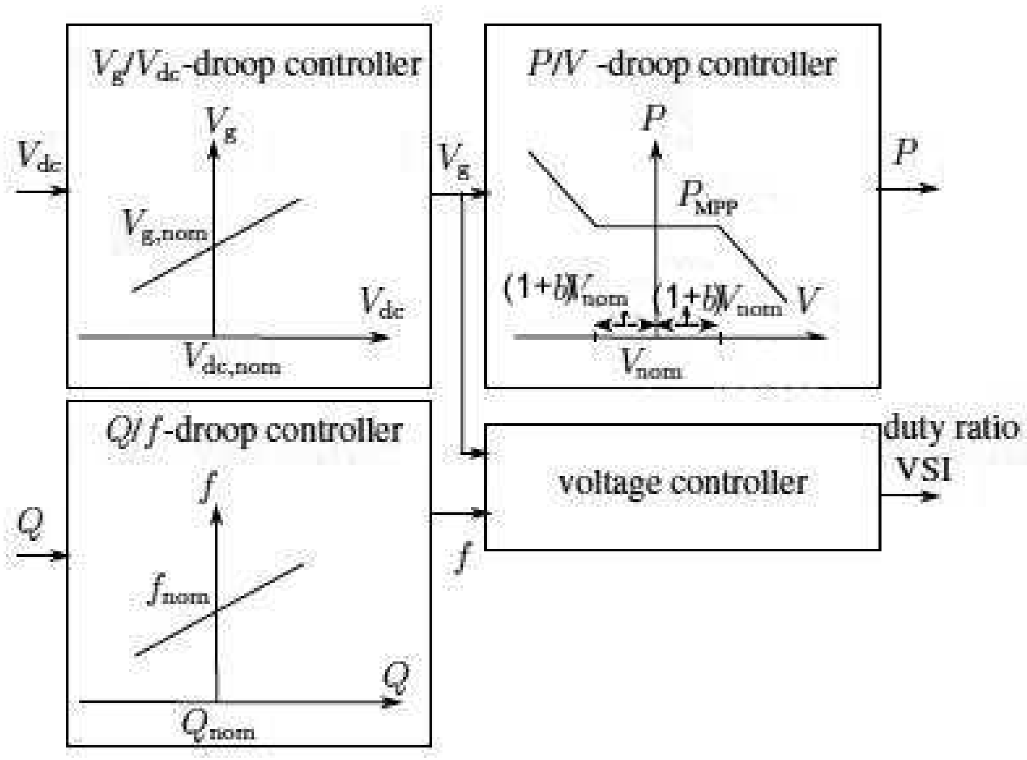

Figure 12. VBD control, active and reactive power controls. Combined operation of the droop controllers to determine the set value of the grid voltage [22].

min intervals of the second day during which the P/V control was enabled. Indeed, during these periods, the rms voltage at node 14 exceeded the reference value of the droop control V_{up} and due to this, the control was enabled in order to modify the injected P of the unit. As a result, the nodal voltage during these intervals was gradually smoothed in order to avoid an eventual cut-off of the unit.

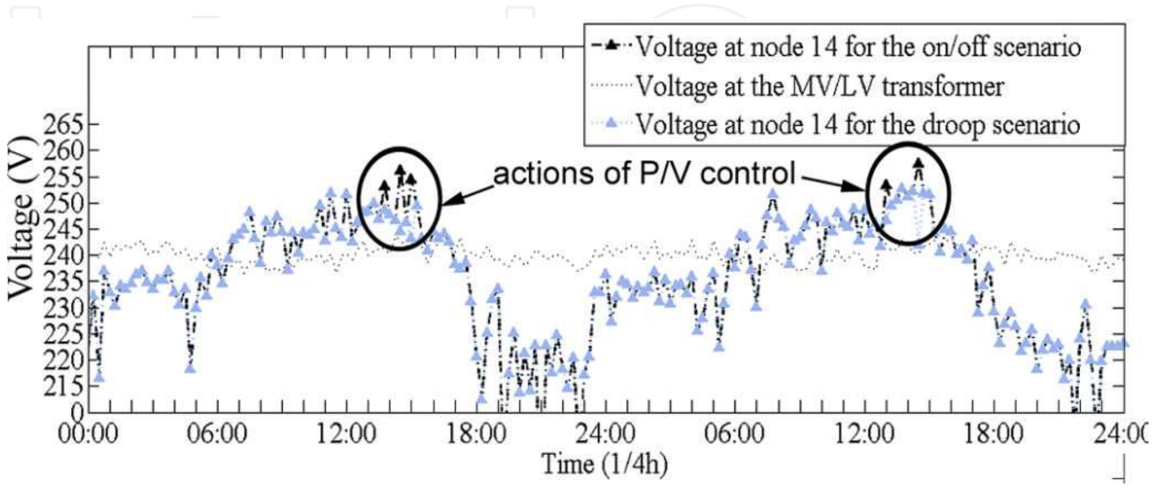

Figure 13. The 15-min voltage at node 14 for the on–off control and the droop scenario during two typical July days.

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Obviously, this gradual smoothing of the voltage profile induces the curtailment of an amount of active PV power. As demonstrated in reference [23], the instantaneous curtailed PV energy can often be much more direct and higher for the on–off control. This argument can foster the acceptance of a certain control strategy, such as the P/V droop control, by the concerned PV customers. The long-term impact of such mitigation solutions on the income of the PV producer and on the operation and maintenance cost of the network, which is currently assigned to the DSO, should be evaluated keeping in mind the principle of Figures 1 and 2.

The presented evaluation that takes into account, in a fast optimized manner, multiple network states and not only the worst-case ones can lead to technical solutions that should be tailored to the special needs and necessary security level of each individual network. Moreover, the analysis and design of the LV distribution network with the presented probabilistic framework contribute to a more rigorous analysis of the MV distribution network. Indeed, when studying the MV network, downstream LV feeders are reduced to P–Q buses defined by the power flow at their root nodes. Most often, the time variation of this power flow, due to PV injection and random loads, is not taken into account. Section 2 introduces a probabilistic methodology that aims at analysing the MV distribution network and uses aggregated load and generation profiles at the MV/LV interface obtained thanks to the presented probabilistic framework. The impact of time variation of load and generation profiles in the LV network in this way is considered in the analysis of the MV network as well.

3. Investment planning at the MV level

Originally, distribution networks were oversized in order to easily ensure the connection of new clients without requiring the upgrade or the replacement of the equipment. However, the constant increase of load and generation, although the network infrastructure has not increased accordingly, induces a global system operation closer to its limits. In particular, this may lead to excessive line power flows that can be destructive not only for the network equipment but also for the end-user material. Indeed, important current flows may infer unintended line congestions as well as an extensive increase of the transformer load that can potentially reduce its lifetime [24]. Moreover, as the voltage drop depends not only on the impedance of the line but also on the line power flows, the voltage profile can locally fluctuate outside its acceptable limits. Although the overvoltages are more dangerous for electrical devices, both low- and high-voltage issues have to be taken into account in the regulation of distribution networks. However, this objective of ensuring a good voltage profile can be in conflict with the minimization of line losses that are very costly for the DSO, in the range of 50 euros/MWh, concerning the Belgian situation. Indeed, for a same demand of power, the reduction of line losses is obtained by a voltage rise. Consequently, the DSO will look for a trade-off between the quality of the delivered power and the economic losses.

Currently, several strategies can be used to improve the real-time operation of the grid. The most popular method is the use of on-load tap changer (OLTC) of transformer. The principle is to mechanically adjust the turn ratio of the transformer winding, usually with regard to a local measurement of the current. It should be noted that the dynamic of an OLTC is relatively fast with a total operation time between 3 and 10 s, depending on its design [25].

Then, the reactive power compensation devices are also very useful to get a better voltage profile in a power system with an X/R ratio higher than one. Devices such as the static VAR compensator or static synchronous compensator (STATCOM) have the interesting ability to work in both inductive and capacitive modes. Furthermore, the technology is well developed and financially affordable compared to other techniques [26].

In recent years, the possibility of investing in storage is gaining credibility [27]. Indeed, although the most mature technology (i.e. the pumped hydro) is not appropriate for the needs of distribution systems, other technologies are expected to become increasingly important in the near future. In this way, stationary batteries seem really appealing due to their good flexibility regarding the input and output power. Nonetheless, the cost is still very high and their success will largely depend on the cost reduction. Then, the compressed-air energy storage (CAES) could be a solution in the coming years, but its integration is hampered by its low efficiency and limited operational flexibility. Finally, the hydrogen storage technology is showing promise but is not expected to be sufficiently developed to be competitive before 2020.

Then, the possibility to use the reactive power produced by distributed generation (DG) units is also an investigated alternative [28]. However, this method has a limited margin due to the current legislation restricting the reactive power flows at the connection node of each client (generators as well as industrial customers). Moreover, as there is currently no market for ancillary services at the distribution level, the customers have no incentive to help the DSO in its task of maintaining optimal operating conditions.

Finally, if the power flows far exceed the network capacity, the system reinforcement may constitute the most viable solution.

Note that the DG units connected to the distribution grid are automatically disconnected when the network frequency or the local voltage exceeds the limits defined by the legislation. Therefore, another major asset of a local control of the network operating conditions is the avoidance of such disconnections, which may have to be financially compensated, depending on the contract between the producer and the DSO.

In this study, a new procedure aiming at ensuring the respect of the operational constraints of the distribution grid at any time is implemented. This amounts to avoiding any congestion or voltage violation. The crucial role of maintaining the frequency balance is indeed assigned to the transmission system operator (TSO). The general structure of the proposed method is represented in Figure 14 and is divided into three parts. First, a two-step planning procedure is conducted for identifying the optimal strategies that the DSO has to implement in order to optimally improve the long-term operation of the MV network. As most of the Belgian HV/MV transformers are already equipped with OLTC devices, and given the current context not fostering the reactive control of DG units, the study is mainly focusing on the installation of VAR compensators and storage utilities. In this way, the first part of the planning process evaluates the best positioning of these network regulation devices, whereas the second part consists in sizing the devices by taking cost constraints into account. Obviously, the final choice of the positioning will depend on the geographic and administrative considerations, which will not be considered here, as they have no repercussions on the philosophy and the principle of the method. The second part consists in simulating the real-time centralized control of the system, which is performed by optimizing the command of the network regulation devices in function of the network state. This operation is thus carried out for a large number of simulated states. Finally, the last part is post-processing whose purpose is to compare the probability of constraint violations as well as the total line losses before and after the installation of the network regulation devices.

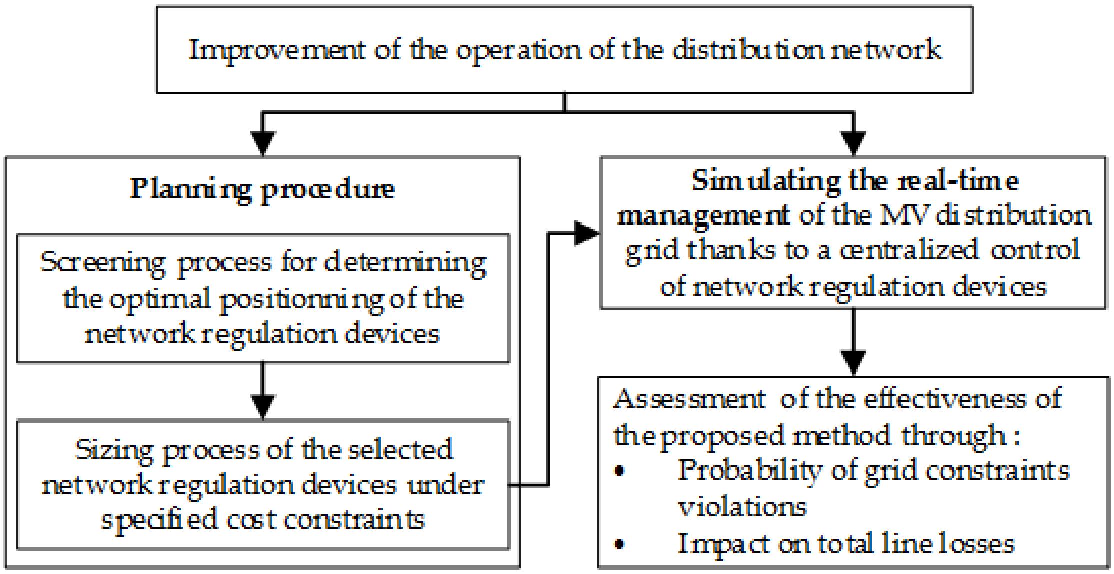

Figure 14. Structure of the proposed procedure for the improvement of operational efficiency in MV distribution grids.

The developed methodologies for the planning procedure and the real-time simulation of the network states are both developed in a non-sequential Monte Carlo procedure due to the lack of real-time measurements, especially at the MV/LV interface. This issue concerns less the industrial area, as quarter-hourly energy flow recordings are mandatory for the Belgian consumers with an installed power higher than 100 kVA. Indeed, these clients are not only invoiced for their actual energy consumption but also for their peak power, regardless of its duration.

When working in a Monte Carlo environment, it is essential that the underlying simulations are fast and efficient in order to avoid an excessive simulation time. Therefore, because of its excellent trade-off between simulation time and quality of the results, the experimental design method was privileged. Indeed, as explained hereafter, this method, which is also referred to as design of experiments, is perfectly suited for conducting the desired studies (i.e. planning procedure and simulation of the centralized control of network regulation devices). Then, as both proposed studies require performing load-flow studies in order to determine the voltage profile and the power losses within the system, a fast, simplified computation, based on the analytical approach presented in reference [29], was implemented. However, in its initial form, this algorithm was designed for a single radial feeder without ramifications; it had to be thus adapted in order to be used on the traditional tree-shape structure of MV distribution networks.

Since the first issues originating from the progressive introduction of renewable energy generation over the past years, the improvement of MV network operation has become a real matter of concern. In this way, in recent studies [30], [31], new voltage-control methods combining the advantages of OLTC action and D-STATCOM response were proposed. However, in practice, this procedure can hardly be implemented as the transformers are not necessarily directly managed by the distribution system operator (i.e. most of the Belgian transformers, even those installed at the distribution level, are the property of the TSO).

This study is intended to be more complete and takes into account the reality of the economic and technical constraints by evaluating the impact of a local centralized control downstream each of the HV/MV transformers. The control is thus at the interface between a decentralized control performed at each connection node of the network regulation devices and a centralized control applied on a national scale.

Practically, this work is structured as follows. First, the principle and the basic concepts of the DOE method are introduced. Then, the proposed methodology is fully presented and applied to an existing MV-Belgian network. Finally, the collected results are exposed and discussed.

3.1. General principle of the DOE method

Design of experiments constitutes a powerful tool to establish and study the effects of multiple inputs on a desired output. The method thus involves two types of variables, the response of interest (y) and the k predictor variables (ξ_1, ξ_2, ..., ξ_k), which are referred to as factors. These are chosen by the experimenter as variables that are supposed to influence the response. The aim of the method is to establish a mathematical description of the system of the form [32]:

$$y = f(\xi_1, \xi_2, \ldots, \xi_k) + \varepsilon \tag{4}$$

where ε is the error between the real observed response y and the result given by the model. In order to simplify future calculations, the natural variables (ξ_1, ξ_2, ..., ξ_k) expressed in physical units are transformed in coded dimensionless variables (x_1, x_2, ..., x_k). Moreover, bound constraints need to be defined for each factor. These lower and upper bounds are, respectively, called 'low' and 'high' levels and are characterized in coded variables by '—1' and '+1'.

There are different experimental designs, which are commonly divided into two main categories, given the desired objective. The first one constitutes a screening study, which is used to determine the factors that really influence the outcome. This procedure allows therefore keeping only the most influential factors in the context of a selection process. The second one, which is called response surface methodology (RSM), is performed when the objective is to find the optimal settings of the factors in order to obtain the desired system optimization. Both methods can therefore be used in a complementary way.

Each design is characterized by its own mathematical approximation of the response y. Typically, the experimental designs engineered for a screening process are first-order models including the interactions between factors. On the other hand, the designs used in the context of an optimization procedure require flexibility for modelling curvatures in the response surface. Mostly, these are thus second- or even third-order models containing a small number of interactions. Overall, the general form of the model is the following:

$$y = a_0 + \sum_{j=1}^{k} a_j x_j + \sum_{j=1}^{k} \sum_{l=1}^{k} a_{jl} x_j x_l + \ldots + a_{jl\ldots k} x_j x_l \ldots x_k + \varepsilon \tag{5}$$

The parameters $a_0, \quad a_j, \quad a_{jl}, \quad \ldots$ are called the regression coefficients of the model and constitute the unknowns of the problem. In order to solve it, the model (5) is usually written in matrix notation. Considering that n experiments were performed and that the mathematical model encompasses p coefficients, the model can be expressed as:

$$\underbrace{y}_{(n\times 1)} = \underbrace{X}_{(n\times p)} \cdot \underbrace{a}_{(p\times 1)} + \underbrace{\varepsilon}_{(n\times 1)} \tag{6}$$

where, y is called the response vector, X the full design matrix, a the regression coefficients vector and ε the residuals vector. This system consists of n equations for $n + p$ unknowns (p regression coefficients and n residuals). The desired regression coefficients are determined thanks to the least squares method, whose principle is to minimize the sum of squares of the residuals [32]. These estimated coefficients, noted $\bar{a}$, are then given as follows [32]:

$$\bar{a} = \left(X'X\right)^{-1} X'y \tag{7}$$

Finally, the fitted regression model is:

$$\bar{y} = X\bar{a} = X\left(X'X\right)^{-1} X'y \tag{8}$$

where y represents the real value of a response measured following an experiment and $\bar{y}$ the value of the response calculated based on the mathematical model of y (where the least-square estimators $\bar{a}$ were previously determined). The residual ε of the model, that is, the differences between the actual observations y and the corresponding fitted values $\bar{y}$, can be computed as follows:

$$\varepsilon = y - \bar{y} \tag{9}$$

3.2. The screening of significant parameters

The screening study is used to quantify the significance of each factor on the response and is therefore very useful in the context of selection procedure or reduction of the problem size. Here, this method is applied in order to find the best area for installing the network regulation devices. Note that the goal is not to precisely determine an exact location, since the probability that this node can really be used in practice is highly insignificant. Furthermore, this approach allows to substantially decrease the number of factors and to generate important time savings. The underlying aim of the study is thus to avoid the upgrading of the feeders, as such a solution is not economically viable for DSOs, especially considering the current trend to install underground power cables. Practically, two different screening studies are carried out, one for each of the two envisaged control means (i.e. VAR compensators and storage devices). Recall that, due to the relatively low extra costs compared with normal transformers as well as their high efficiency, OLTC devices are already installed in HV/MV substations. Moreover, the control of the reactive power of DG units does not seem feasible at the present time. At the end of the screening study, we will therefore obtain the most favourable areas for installing VAR compensators and storage facilities.

The response y must quantify the effect of the factors on the violations of the operating conditions. The response is thus defined as a weighted sum of the violated constraints within the network. More precisely, the computation consists in the summation of three contributions y_{1a}, y_{1b} and y_2. The first two terms relate to the voltage violations, which are defined according to the European EN 50160 standard and are computed as follows:

$$
\begin{aligned}
y_{1a} &= \sum_{i=1}^{N} \left(V_i - 1.1V_{\text{nom}}\right)^2 \qquad \forall\, V_i > 1.1V_{\text{nom}} \\
y_{1b} &= \sum_{i=1}^{N} \left(V_i - 0.9V_{\text{nom}}\right)^2 \qquad \forall\, V_i < 0.9V_{\text{nom}}
\end{aligned}
\tag{10}
$$

where N is the number of nodes of the studied network. The third term concerns the line congestions, which depend on the thermal limits of the cables.

$$
y_2 = \sum_{l=1}^{L} \left(S_l - S_{\max}\right)^2 \qquad \forall\, S_l > S_{\max} \tag{11}
$$

where L is the number of lines. Finally, the response can be expressed as:

$$
y = w_1(y_{1a} + y_{1b}) + w_2 y_2 \tag{12}
$$

where w_1 and w_2 represent the respective weights associated to the voltage and power flow violations with $w_1 + w_2 = 1$. When the system is not at risk, the response is therefore equal to zero.

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Beyond its simplicity of implementation, the DOE approach presents another highly interesting asset. The coefficients of the mathematical model have indeed a physical meaning, and their values can be interpreted as a quantitative reflection of the effect of the factors on the response. This interesting and useful property is illustrated in Figure 15 for $k = 2$ (factors x_1 and x_2).

$$y(x_1, x_2) = a_0 + \underbrace{a_1}_{\substack{\text{Effect of the factor } x_1 \\ \text{on the response } y}} x_1 + a_2 x_2 + \underbrace{a_{12}}_{\substack{\text{Effect of the interaction} \\ \text{between } x_1 \text{ and } x_2 \text{ on } y}} x_1 x_2$$

Figure 15. Representation of the physical meaning of the coefficients of the model as the response of interest.

The number k of factors of the analytical model is thus equal to the number of sub-areas defined within the studied distribution grid. The first step is to arbitrarily divide the network into a small number of representative geographic areas based on its topology. The sensibility of each area for both network regulation devices is evaluated through the impact of a device installed at the closest node of the centre on the considered section. For consistency, the same pre-sizing is considered for all devices of the same type. The general principle of the screening study is shown in Figure 16.

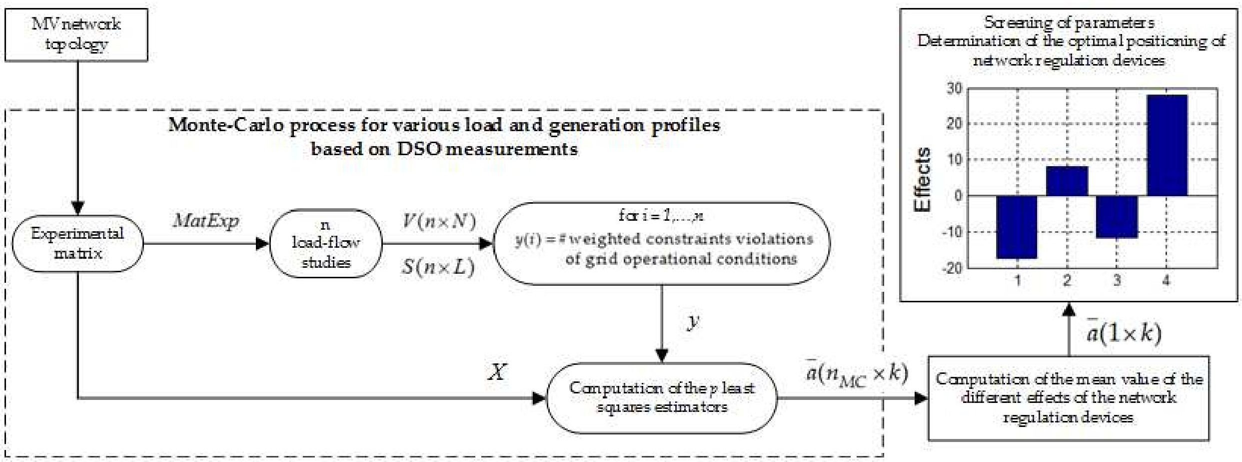

Figure 16. Flowchart of the principle of the implemented screening study.

First, the network topology is used to define all the possible positioning configurations of the network regulation devices. In this study, these are either reactive power compensators or storage devices. This leads to the definition of the experimental matrix $MatExp(n \times k)$, which contains the real values of the k factors and thus defines the n experiments to be performed. An experiment consists in a load-flow calculation, so as to obtain the voltage profile and the power flows in each line. Each experiment is carried out for specific values of the k factors (i.e. network regulation devices), which are defined by the considered experimental design. The full design matrix X is easily inferred from the experimental matrix [32], and knowing the response vector y, the regression variables can be determined by (7).

In order to take the non-deterministic effects of the load and the generation into account, the screening process is implemented in a non-chronological Monte Carlo environment. Such a study allows simulating a large number of operating states of the network. For each of them, the influence of the network regulation devices is evaluated. The process thus simulates the random behaviour of the different MV clients as well as the MV/LV substation by the means of a random sampling of the consumed and/or injected power at each bus. More details about the procedure are given in Section 3.5.1.

The importance of the location of each area for installing network regulation devices is then computed by averaging the effects provided by the screening procedure conducted for each of the n_{MC} Monte Carlo iteration. The results can then be plotted and analysed.

3.3. Sizing procedure of the selected devices

After the determination of the most favourable areas for respectively installing a reactive power compensator and a storage utility, the sizing of these devices is carried out. As one of the objectives of the method is to illustrate the assets of implementing a centralized control at the MV level, the sizing procedure is applied for more than one network regulation device. For simplicity as well as economic reasons, only two devices are considered in this work. Moreover, as the storage technology is still too expensive, the possibility to install two storage utilities is not considered. As a result, two different scenarios are investigated. The first one focuses on the combined installation of a VAR compensator and a storage device, whereas the second one evaluates the possibility to invest in two reactive power compensators.

The sizing of the storage utility concerns only its output power. Indeed, the energy sizing is less critical for the DSO than it would be for an operator eager to maximize its return on investment, since the DSO is not to take the market considerations into account. Its only focus is to use the storage device when it is necessary for alleviating stressed conditions within its grid and to take advantage of the non-critical situations to adjust the amount of stored energy. However, such a control strategy is outside the framework of this study.

As in the screening process, the sizing procedure makes use of Monte Carlo simulations for modelling the different network states. For each simulation, an optimal control of the selected network regulation devices is carried out. Thus, this requires the use of a fast optimization tool, which led to the choice of the response surface methodology. The response is the same as the one used in the screening process (i.e. a weighted sum of the constraints violations); and the response surface thus models the variation of this response with regard to the output power of the two selected regulation devices. The mathematical model used for the study is of the form:

$$y = a_0 + \sum_{j=1}^{k} a_j x_j + \sum_{j=1}^{k} \sum_{l=j+1}^{k} a_{jl} x_j x_l + \sum_{j=1}^{k} a_{jj} x_j^2 + e \tag{13}$$

where y is determined by (7) and the x_j and x_l values are the output powers of the network regulation devices.

The purpose of optimization is to find the configuration of the control devices that eliminates all constraint violations while minimizing their interaction (i.e. power exchanges) with the grid. Mathematically, it amounts to find the intersection between the response surface and the plane $y = 0$. The result is thus a line segment and the choice of the optimal point then depends on the considered scenario. In the first scenario, as the storage is currently a much more expensive solution, the optimal configuration is the segment point with the lowest value of active power provided by the storage device. In the second scenario, the aim is to minimize the sum of both reactive power contributions. Indeed, according to the Siemens database [33], the installation price increases approximately linearly with the maximal installed reactive power.

The optimal values given at the end of each Monte Carlo simulation are logged. In this way, at the end of the simulations, the DSO disposes of useful information. Indeed, the output power of devices can be directly translated in installation costs and, given the different values of the regulation devices, the DSO is then able to adapt its investment decision as regards the technical and economic considerations.

3.4. Centralized real-time management of the distribution grid

The method proposes to use a centralized control of each of the network regulation devices of the considered distribution grid. Indeed, the current SVC/STATCOM devices compare the voltage at their connection node to a fixed reference voltage in order to bring back the voltage at the defined reference level. But sometimes, it could be interesting to change that reference depending on the location of the device in the grid. For example, to lower it when there is an increased power generation coming from DG units combined with a low demand. In this context, the output power of the storage devices would be adapted by a remote control of power electronics.

The strategy of the control depends directly on the presence of operational constraints violations. On the one hand, if there are such violations, the aim is to overcome the issue with an optimal use of the network regulation devices. However, with several devices, several configurations can potentially solve the problem. In such a case, the DSO is interested to opt for the configuration that minimizes the line losses. On the other hand, if there is no problem, different strategies can be envisaged. The most straightforward option is to do nothing, which will minimize the number of cycles of the devices and, as a result, increase their lifetime. For the sake of simplicity, this strategy was implemented in this study. The second one is to use the control devices for reducing the line losses. Such an action has to be carried out only if it generates worthwhile financial profit. Finally, if a storage facility is available, its energy level can be adapted in anticipation of the future needs.

The optimization is carried out by using the same response surface methodology than the one used in the sizing procedure (i.e. same response and same variables).

3.5. Application of the DOE method to an existing radial MV grid

3.5.1. Modelling of the MV network

The simulation of the statistical behaviour of the different industrial loads comes from energy flows directly collected at the connection node by the DSO. The power injections at MV/LV substation is provided by the aggregated power profiles determined in the LV planning tool in Section 1. As the PV installations are the property of industrial companies, these are also equipped with SM. This is not the case with most of the wind farms that often belong to independent operators that directly participate in the electricity market and do not depend on the DSO. Consequently, the power generated by wind farms is inferred from openly accessible wind speeds. As data for a large number of years are available, those are perfectly adapted to a Monte Carlo procedure. The wind speed values can then be converted into a value of active power according to the following power curve [34]:

$$\begin{cases} P = 0,\, W_t < v_{\mathrm{ci}} \\ P = a + b \cdot W_t^2,\, v_{\mathrm{ci}} < W_t < v_{\mathrm{r}} \\ P = P_r,\, v_{\mathrm{r}} < W_t < v_{\mathrm{co}} \\ P = 0,\, W_t > v_{\mathrm{co}} \end{cases} \tag{14}$$

where W_t is the wind speed and v_{ci}, v_{r}, v_{co} are, respectively, the cut-in, rated and cut-out wind speeds of the power curve. P_r is the nominal power of the wind generator and the parameters a and b are defined as in reference [34].

Therefore, considering the theoretical number of the data available, the same pseudo-chronological Monte Carlo procedure as the aforementioned LV planning tool could be performed. However, several impediments such as the difficulty to gather the data of all clients combined with the noticeable loss of data and measurement errors led to the implementation of a non-sequential Monte Carlo.

Concerning the reactive power of DG installations, it must comply with the operating point of DG as well as the national legislation. This work is based on Belgian rules [3], but could easily be adapted in order to suit other legislation.

The reactive power compensators are modelled by their reactive power consumed (inductive mode) or injected (capacitive mode) into the grid. Then, given the price and the maturity of other storage technologies, the battery is currently the most appropriate solution for the desired application of providing ancillary services to the distribution grid. The pricing of these devices is determined by manufacturers, which will not be revealed here for confidentiality purposes.

As previously mentioned, the permitted range of voltage fluctuations is defined by the EN 50160 standard that allows a variation of ±10% around the nominal value. The thermal limits of power cables are defined as the maximum current that can flow in the conductors without

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inducing excessive heating. Indeed, the current flowing in the conductors generates heat that needs to be eliminated in the surrounding environment. This diffusion is made difficult by the important thermal resistances of the insulating materials in cables and by the surrounding environment, especially in the case of underground cables. In order to preserve the network security, the DSO must ensure that such situations do not occur.

3.5.2. Definition of the network and of the factors

The DOE method is used on a 28-bus radial network, which is highly critical regarding the risks of congestion and voltage violation, because of the high penetration rate of DG units such as wind farms or large PV plants. These are installed at nodes 6, 10, 15, 23 and 28. This situation is indeed stimulated by the current financial attractiveness of investing in renewable energies. Consequently, in order to avoid an expensive reinforcement of the grid, the introduction of network regulation devices constitutes an interesting solution to investigate. The single-phase diagram of this 20-kV system is shown in Figure 17. The representation of the grid is purposefully divided into eight different sub-areas, which are arbitrarily chosen and correspond to the areas whose influence is evaluated in the screening process. The resistance and reactance per kilometre of each line section are, respectively, 0.098 and 0.106 Ω/km, whereas the distance between nodes varies from 2 to 10 km. The definition of the rated power of each load and DG unit is shown in Table 1.

bus	P_L (kW)	P_G (kW)	bus	P_L (kW)	P_G (kW)
01	0	0	15	0	3900
02	240	0	16	190	0
03	190	0	17	160	0
04	220	0	18	150	0
05	100	0	19	230	0
06	0	2700	20	100	0
07	160	0	21	160	0
08	100	0	22	140	0
09	180	0	23	170	2700
10	260	3900	24	110	0
11	190	0	25	260	0
12	130	0	26	170	0
13	90	0	27	160	0
14	180	0	28	140	3900

Table 1. Data of the 28-bus grid.

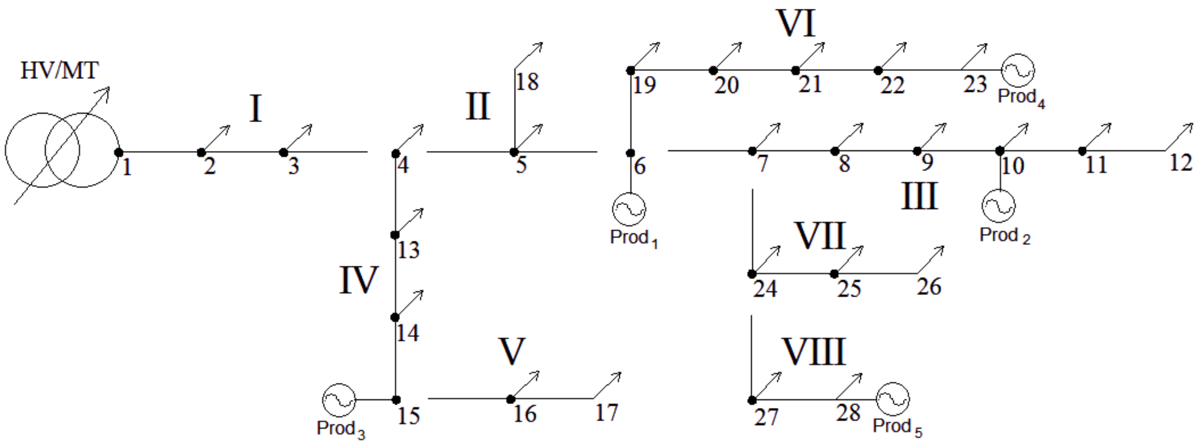

Figure 17. The single-phase diagram of the investigated 28-bus grid.

3.5.3. The screening step

A preliminary analysis of the network behaviour showed that the congestion issues are exclusively observed in areas I and II of the grid, whereas the voltage issues tend to occur at the most distant nodes of the HV/MV substation. This gives useful information even before starting the screening procedure. However, the intuitive solution that consists in positioning one control device at the beginning of the grid and the other one at the extremity is likely to be inefficient. Indeed, the power flows originating from the transformer are representative of the power demand of the downstream loads. Therefore, the benefit of a control device installed in the neighbourhood of the substation is highly localized (i.e. area between the transformer and the control device) and this solution has a good probability to be suboptimal. The determination of the best solution is thus not trivial and requires a more thorough study.

Two screening studies are therefore carried out, both aiming at finding the optimal location to install respectively a reactive power compensator and a storage device. The influence of the eight areas represented in Figure 17 is investigated. For consistency, the same sizing is considered for all devices of the same type. In this way, the maximal sizing of the VAR compensators is adapted to the maximum reactive load of the case study and the maximal output power of the battery is 1 MW, which corresponds to the current upper limit proposed by the manufacturers.

The results of both screening studies are represented in Figure 18. The bar chart representation of the effects is privileged for its simplicity of interpretation. The height of a bar associated to a factor represents indeed the effect of this factor on the response. Therefore, the highest bars correspond to the most influential (and thus efficient) factors.

As expected, the results are quite similar for both scenarios. Indeed, the areas located near the end of the grid are more appropriate than those near the HV/MV transformers in the context of investing in network regulation devices for improving the MV grid operation. This can be explained by the importance of the line impedance. However, while the best place for the

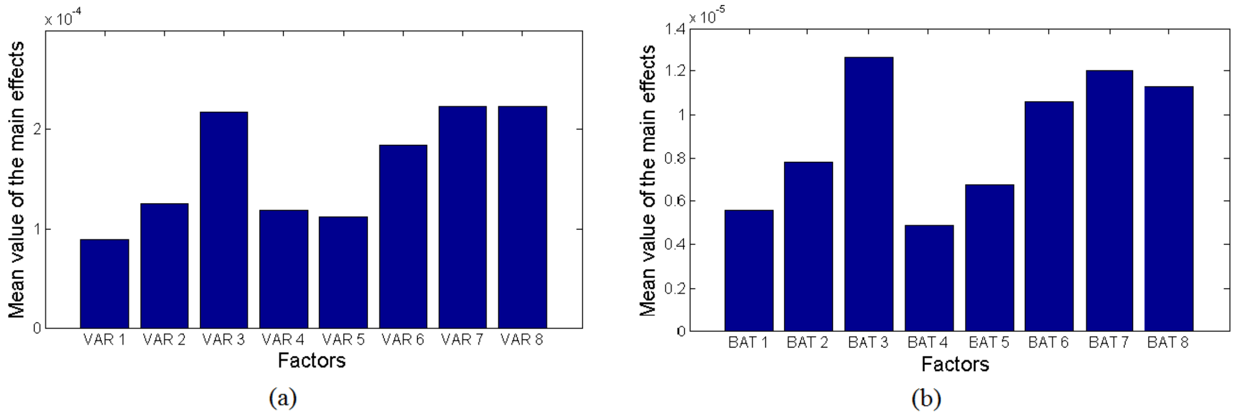

Figure 18. Influence of the eight selected areas for the installation of a VAR compensator (a) and a storage device (b).

storage device is the end of the main feeder in area III, the VAR compensator will have more effect if it is installed near node 28 in area VIII.

3.5.4. The sizing step

The purpose of the sizing step is to use the network regulation devices in order to improve the operation of the grid for a large number of simulated network states. All the optimal values of these devices are then collected as they will constitute the basis for the sizing decision. Indeed, thanks to manufacturer offers, the output power can be associated to a price. The objective is to allow the DSO to make the best decision with regard to the investment costs and the resulting effects on the network operation.

For each network state, the centralized control strategy is carried out by using the aforementioned response surface methodology. The goodness of fit of the model (13) is quantified through the coefficient of determination R^2 [32]. This R^2 coefficient is included in the [0, 1] interval and is equal to one when all the experimental points correspond exactly to those determined by the fitted model. Conversely, if the quality of the model is decreasing, the value of R^2 will drop accordingly.

As previously mentioned, two scenarios are considered here. In the first one, the combined control of a VAR compensator with a storage device is studied while the second one focuses on the optimal regulation of two reactive power compensators. It should be noted that the range of variation of the reactive power compensator is symmetrical ($-Q_{max}$, $+Q_{max}$).

The general model of the polynomial approximation of the response for the first scenario becomes:

$$y = a_0 + a_1.P_1 + a_2.Q_{C2} + a_{12}.P_1.Q_{C2} + a_{11}.P_1^2 + a_{22}.Q_{C2}{}^2 \tag{15}$$

The optimal values of network storage devices for both defined scenarios are represented in Figure 19.

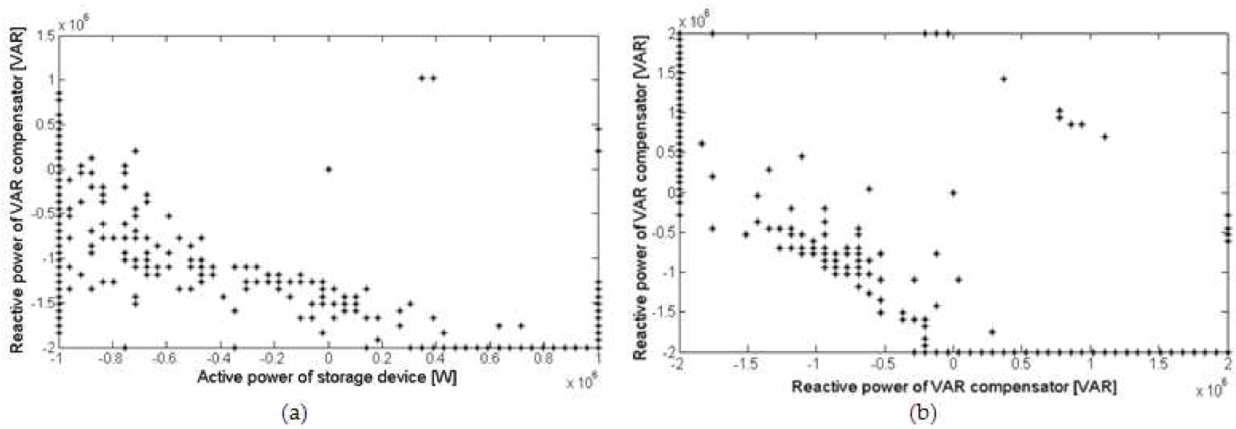

Figure 19. Mapping of the optimal values of the control devices for all simulated network states.

Before interpreting the results, it is important to focus on their accuracy by evaluating the quality of the model used to determine the optimal values of the control devices for each of the Monte Carlo simulation. To that end, the parameter R^2 is assessed for each iteration and the averaged value for both scenarios is then computed. These values are, respectively, equal to 0.88 and 0.89, which indicates a good adjustment of the fitted model with the experimental data.

In the first scenario, as the current maturity of the battery technology does not allow having an output power higher than 1 MW, a significant part of the optimal value is close or equal to the maximum value. However, if the sizing of the VAR compensator is limited to 1.6 MVAR, more than 85% of the constraint violations are eliminated and this solution can therefore constitute a good compromise for the DSO. In the second scenario, it can be seen that a large part of the optimal point corresponds to opposite operating modes of the two VAR compensators (i.e. one is injecting reactive power while the other one is in inductive mode). This can be explained by the conflicting nature of the concurrent elimination of voltage and congestion issues. Indeed, as the line currents are fixed by the power demand, the removal of line congestions requires increasing the voltage. However, if overvoltages are already observed in other parts of the grid, the issue can hardly be solved and necessitates opposite actions of control devices. The nature of their actions then depends on their positioning with regard to the operational constraints violations.

3.5.5. The simulation of the real-time management of the grid

In this method, network regulation devices are used in order to ensure an optimal operation of the network. This objective is translated in the removal of all constraint violations of network operational conditions. The process consists therefore in a state-by-state optimization based on the response surface methodology carried out for a large number of typical years. The effectiveness of the proposed methodology is then tested by taking as evaluation criteria the probabilities of voltage violation and the presence of congestions. The total line losses with and without the centralized control are also compared.

The simulation of the real-time management of the grid is performed for both defined scenarios with their predetermined sizing. In scenario 1, the battery has a maximum output power of 1 MW and the VAR compensator can vary between +1.6 and −1.6 MVAR. The second scenario simulates the centralized control of two reactive power compensators of 2 MVAR. Figures 20 and 21 show the comparison of constraint violations with and without the implemented control for the first and second scenario, respectively.

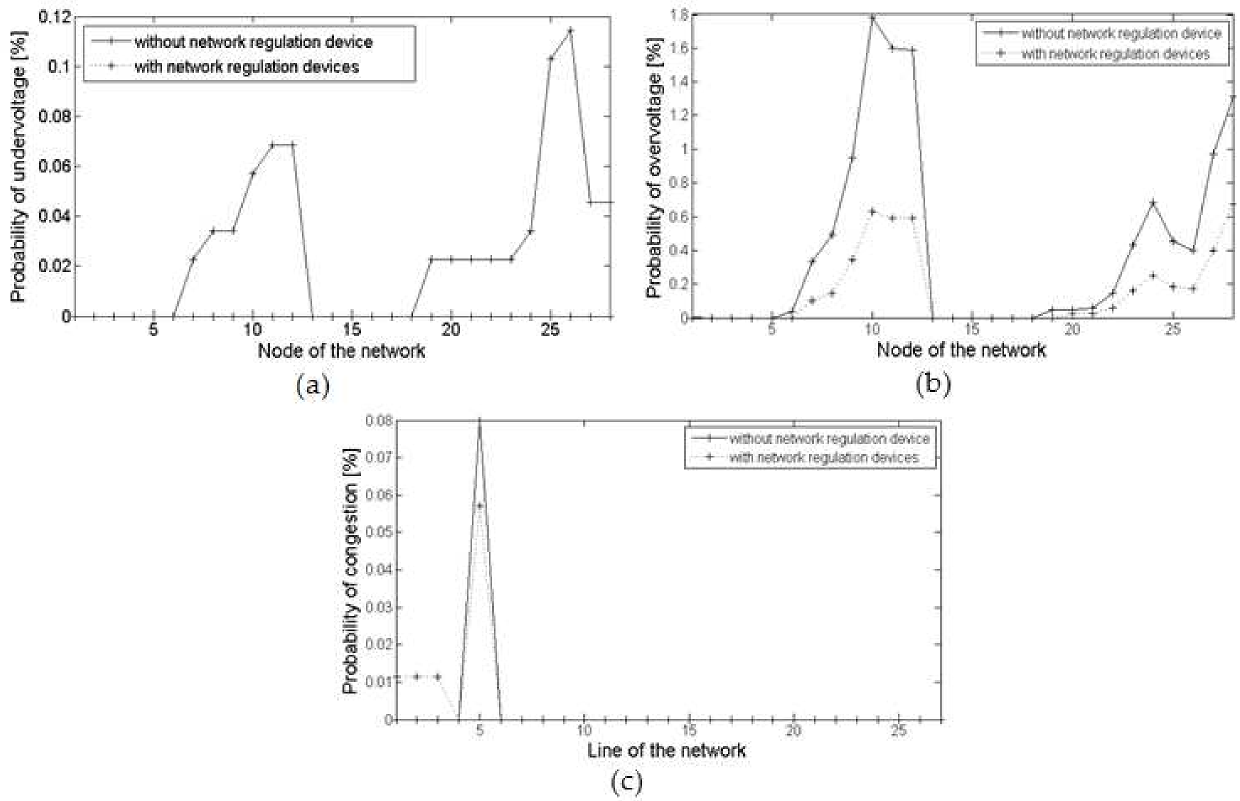

Figure 20. Probability of undervoltage (a), overvoltage (b) and congestion (c) for scenario 1.

In both investigated variants, the undervoltage issues have been completely removed. However, the number of overvoltages has significantly decreased, but they could not be totally eradicated. The probability of congestion has even increased for some nodes, which highlights the difficulty to combine the objectives of simultaneously alleviating overvoltage and congestion issues. In such a case, the DSO would have no other choice than to have recourse to a curtailment of DG units, which may be very expensive. In this context, the research concerning the implementation of load-shifting strategies (e.g. with financial incentives in order to drive customers consuming when there is a lot of generation within the system) is of major importance.

The impact of control strategy on the line losses is represented in Table 2. The results are averaged to represent the total losses of a representative year. Recall that their minimization was not included in the objective function of the study since the reduction of the number of operating cycles of the control devices was privileged.

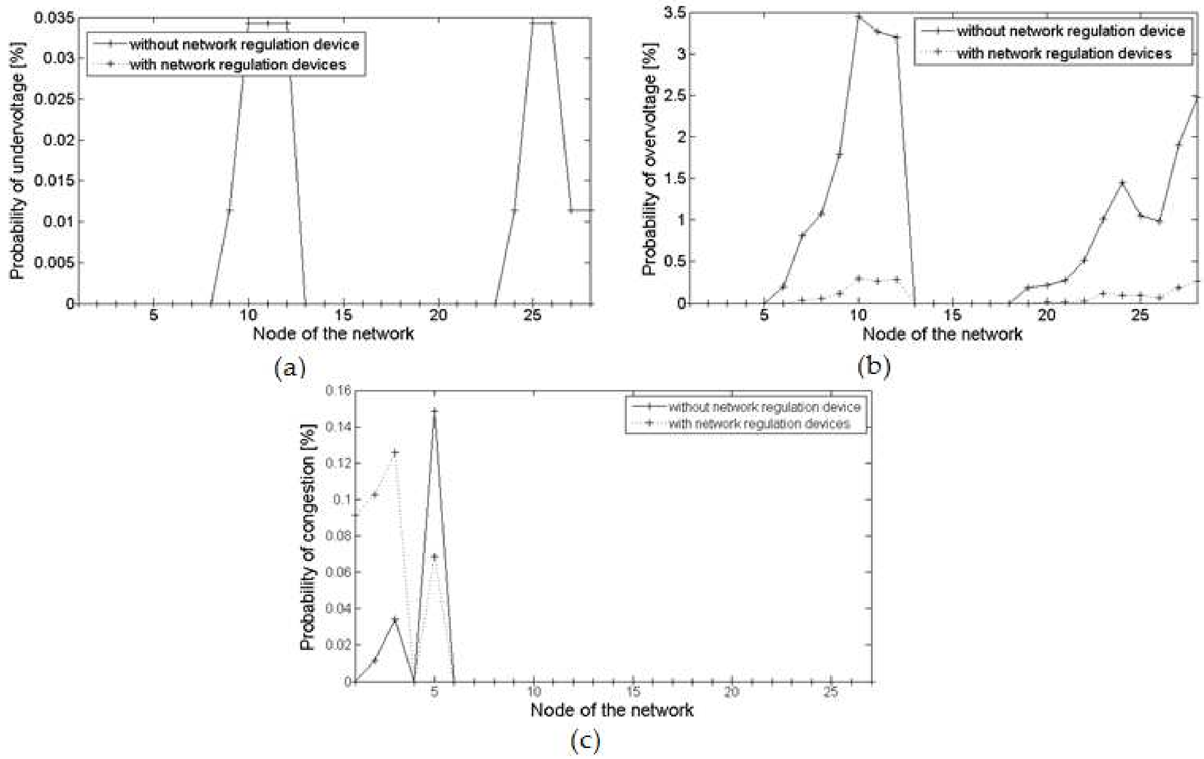

Figure 21. Probability of undervoltage (a), overvoltage (b) and congestion (c) for scenario 2.

	Scenario 1		**Scenario 2**	
	Without control	With control	Without control	With control
Total line losses [MW]	632.89	822.73	665.30	843.07

Table 2. Comparison of the power losses with and without network regulation devices for both scenarios for a typical year.

It can be seen that the amount of power losses increases with the network regulation devices. This can be explained by the presence of several DG units near the end of the grid. Indeed, in order to avoid the overvoltages inferred by the generation of these installations, the storage and the VAR compensators consumed locally active or reactive power. This energy was used by some loads that consequently need to be supplied by the HV/MV transformer. The power flows at the MV output of the substation are thus increased and, as the line losses are proportional to the square of the electrical current, these losses, together with the probability of congestion, rise significantly.

4. Conclusions and perspectives

The natural evolution of distribution networks with high integration of distributed renewable energy sources and random nature of consumptions loads, both uncertain and time variable

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parameters, requires the development of new accurate optimized methodologies for their analysis. To this end, probabilistic approaches are highly recommended since they can simulate distribution networks taking into account the time variation of renewable generation and consumption loads. This chapter introduced two probabilistic planning tools, both developed in a Monte Carlo algorithm environment, for the analysis and planning of LV and MV distribution networks. Section 1 presented a probabilistic framework that analyses in a fast, optimized way the voltage profile along LV feeders, taking into account the uncertainty of their loading parameters node by node, based on real SM data. It can therefore be deployed for the techno-economic evaluation and refinement of solutions to operational problems in LV feeders with high PV penetration. The only prerequisite for its deployment is the availability of SM measurements in the studied LV feeder. This prerequisite goes along with the perspective of a wide rolling out of SM devices in the European LV networks. Section 2 introduced a new method intended to constitute an efficient and realistic planning tool for the DSO. In this way, the study takes three of the main objectives of the DSO into account. Indeed, the screening study aims at finding the best area for installing network regulation devices for minimizing the probability of violations of the operational constraints. Then, the sizing procedure is more complete by accounting for the investment costs. Finally, the centralized control of the number of operating cycles could also easily be implemented for reducing the line losses if such an action turns out to be financially worthwhile.

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