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Solar PV hosting capacity: grid-based vs. market-based scenarios

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***Abstract*—Assessing the capability of a distribution grid to accommodate new solar PV installations, namely its hosting capacity (HC), has been a prevalent research topic. Although providing a technical limit to how much additional solar PV can be integrated into a distribution grid without trespassing operational limits, commonly used HC analysis (HCA) does not consider consumer preferences or the economic feasibility of installations. Using a market-based optimal power flow (MBOPF) and HCA, we compare the economic and technical limits of solar PV capacity integration in low voltage distribution systems (LVDS). Findings illustrate that (1) the PV HC computed using grid limits only does not give a complete picture of solar PV capacity integration potential, (2) linear, deterministic power flow is not a foolproof method for assessing the network-secure amount of PV, and (3) the number of technically feasible installation sites supersedes the economically feasible ones.**

Keywords*—*distribution locational marginal price, hosting capacity, low voltage distribution system, distribution energy market, solar photovoltaic.

I. Introduction

In most of the world, solar photovoltaic (PV) is becoming the lowest-cost option for new electricity generation. An increasingly important role is being played by distributed solar PV systems, which, in 2020-21, saw record capacity additions, constituting 28% of solar PV capacity additions worldwide [1]. In Low Voltage Distribution Systems (LVDSs), high levels of solar PV penetration, with large amounts of power exports into the grid, can result in significant adverse effects pertaining to violation of voltage limits, thermal overloading and power quality deterioration [2].

A network's hosting capacity (HC) reflects the technical limitations imposed by grid infrastructure on the solar PV capacity that can be installed without violating operational limits. For example, studies, such as [3] and [4], have, using power system data, found that Swedish low voltage grids can sustain solar PV systems with capacities between 2.5 and 5.5 kW per household, prior to the need for network reinforcements. While the former study uses a deterministic approach, the latter performs a stochastic hosting capacity analysis (SHCA). In practice, there exist a multitude of methods; a benchmark is provided in [5]. It was found that stochastic PV HC calculation methods, accounting for the stochastic variables and risk of congestion in an LVDS, represent a more realistic overview of grid performance compared to deterministic approaches. However, stochastic methods are usually iterative Monte Carlo based, requiring sizeable computational effort. Moreover, HCAs typically do not care about other practicalities such as roof-top availability or consumer preference because of the high, additional computational burden these entail [6].

In [7], it was found that, in a country like Sweden, HC will unlikely be the limiting factor for the deployment of residential solar PV. Furthermore, in [8], the authors highlight the relevance of socio-economic factors, finding that the likeliness to install solar PV differs among household groups. So while PV HCA can provide a technical limit, guaranteeing network reliability, it is relevant to investigate whether there does not exist an antecedent economic limit considering consumer preferences.

Market-based optimal power flow (MBOPF) approaches can, while considering simplified network constraints, reveal consumer preferences regarding solar PV investments and disclose the effect of economic limits for solar PV integration. In such approaches, nodal prices express the marginal cost of delivering an increment of power to a specific node in the network, reflecting factors such as congestion. Such pricing incentivizes the optimal siting, sizing and operation of distributed generation [9] and, as such, provides an upper bound to economic HC. This price signal is known as the distribution locational marginal price (DLMP) in distribution systems. In [10], the authors propose a joint active and reactive power distribution market in which social welfare is maximized to determine the optimal capacity of pre-located wind turbines and solar PVs under linearized power flow constraints. In [11], the authors apply a similar approach and maximize social welfare under different wind turbine plus solar PV configurations, assessing ramifications on DLMPs and total cost. In both studies, the distribution network operator (DNO) allocates renewable distributed generation (DG), accounting for consumers' benefits and cost reduction.

To compare economic and technical limits to solar PV integration, we perform an MBOPF and an SHCA on 130 non-synthetic, low voltage, European distribution feeders taken from [12]. This is the network of a sub-urban city in Northern Spain, having a European west-coast climate, as in Northern France, UK and Belgium. In the distribution market, we account for active and reactive power trading for an entire year. We assess consumer preferences by specifically modeling heterogeneous energy customers, encompassing both single-household and multi-household consumers, all having the possibility to invest in solar PV considering a perceived investment cost. To endogenize electricity prices and provide feedback between consumer decisions and prices, we include stylized versions of large scale generators and non-residential demand at the slack bus. A network-aware market operator guarantees that network constraints are respected and sets nodal prices. Such an approach enables a system perspective, revealing agents' investment and operational decisions. The overall PV HC calculations are done in two-stage. First, the box limit of each prosumer towards the PV size according to the market model. Thus, individual limits are fed to the stochastic optimal power flow (SOPF) based SHCA method that considers the uncertainties in load and PV generations and chance constraints in bus voltages and branch currents. This provides a sanity check on the feasibility of the PV HC obtained from MBOPF. Furthermore, a comparison with SHCA that considers only technical limits provides insight into which factor is more limiting for an LVDS PV HC, technical grid limits or consumers' preference based on the market parameters.

By comparing economic and technical limits to solar PV integration, we provide greater nuance to the HC literature, informing decision makers that factors beyond network capacity can confine solar PV adoption, warranting the need for apt incentives.

The paper is organized as follows: Section II presents how economic and technical limits are derived. Section III describes our case study, and section IV finds and compares these limits for a series of networks. Section V concludes the paper.

II. Approach

A. Market-based optimal power flow (MBOPF)

To attain the maximum, economically feasible solar PV penetration, we model the long-run Nash equilibrium between producers and consumers in an electricity market, assuming complete integration of wholesale and retail. In this market, all agents have perfect information, and no barriers to entry or exit are present: placing all on a level playing field. Using this modeling approach, agents individually compete in a strategic game. At the equilibrium, each player's strategy is an optimal response to the strategies of others. To solve the equilibrium problem, it is recast as a single optimization problem, as done in [13], with the objective of minimizing total system cost.

Within the market, agents trade active as well as reactive power with the grid. They are remunerated, for exporting, and debited for importing, according to nodal prices: $\lambda^P_{t,n,\phi}$, for active power and, $\lambda^Q_{t,n,\phi}$, for reactive power. The subscripts denote the timestep, node and phase. A network-aware market operator guarantees nodal power balance and determines prices on an hourly basis without imposing price caps. Moreover, the market operator uses linear power flow equations prescribed in [14] to have approximate boundaries in bus voltages and branch currents to avoid congestion.

Market agents encompass large-scale generators as well as consumers, entities comprising single or multiple households, i.e. an apartment block. Non-residential demand is also incorporated as a parameter. While households are located throughout the distribution grid, connected in either single-phase or three-phase, large scale generators and non-residential demand are located at the transmission level, embodied by the slack bus of the studied distribution feeders. The objective of the large scale generators is to maximize profits equivalent to revenues from selling active and reactive power minus operational and investment costs. Due to space constraints, in this work, we only explicitly include the consumer's problem, whose objective is to minimize costs, as shown in (1.1).

Consumers can export or import active and reactive power, at every time step t, on the set of phases they are connected to Φ, via variables $p^N_{t,\phi}$ and $q^N_{t,\phi}$. In the case of export, the corresponding variable will be negative. Additionally, all consumers may invest in solar PV capacity cap^{PV} subject to their perceived solar PV investment cost IC^{PV}. To avoid unrealistic installation sizes, the solar PV capacity that consumers may invest in is bounded by the parameter CAP^{PV}, (1.2), which is 15 kW for each household. Solar PV generation p^{PV}_t, cannot exceed maximum generation, embodied by installed capacity, cap^{PV}, times the solar PV availability factor, AF, as shown in (1.3). All solar PV installations are equipped with a smart inverter that can generate and absorb reactive power at a minimum power factor, κ_{min} , as exemplified in (1.4), based on [15]. Finally, (1.6) and (1.5) denote the consumer's behind-the-meter power balance, stating that their per-phase export (or import) has to equal their demand, denoted by $D^P_{t,\phi}$ for active power and $D^Q_{t,\phi}$, for reactive power, minus their generation from solar PV. The latter is assumed to be distributed equally across the phases they are connected to, hence divided by the number of connected phases: $|\Phi|$.

$$\min \sum_{t\in\mathcal{T}} \sum_{\phi\in\Phi_c} \lambda^P_{t,n,\phi}\cdot p^N_{t,\phi} + \lambda^Q_{t,n,\phi}\cdot q^N_{t,\phi} + IC^{PV}\cdot cap^{PV} \tag{1.1}$$

subject to:

$$0 \le cap^{PV} \le CAP^{PV} \tag{1.2}$$

$$0 \le p^{PV}_t \le cap^{PV} \times AF \qquad \forall t\in\mathcal{T} \tag{1.3}$$

$$\kappa_{min} \le \frac{p^{PV}_t}{\sqrt{(p^{PV}_t)^2 + (q^{PV}_t)^2}} \qquad \forall t\in\mathcal{T} \tag{1.4}$$

$$p^N_{t,\phi} = D^P_{t,\phi} - \frac{p^{PV}_t}{|\Phi|} \qquad \forall t\in\mathcal{T},\phi\in\Phi \tag{1.5}$$

$$q^N_{t,\phi} = D^Q_{t,\phi} - \frac{q^{PV}_t}{|\Phi|} \qquad \forall t\in\mathcal{T},\phi\in\Phi \tag{1.6}$$

B. Stochastic hosting capacity analysis (SHCA)

The most accepted definition of low voltage (LV) grid hosting capacity is *the amount of new generation or consumption that can be accommodated on a given feeder without impacting system operation under existing control and infrastructure configuration* [16]. The available grid PV hosting capacity calculation methods were evaluated and benchmarked in [5]. The study showed that the hosting capacity calculation of an LVDS is a multidimensional stochastic problem and requires a stochastic hosting capacity analysis (SHCA). SHCA methods

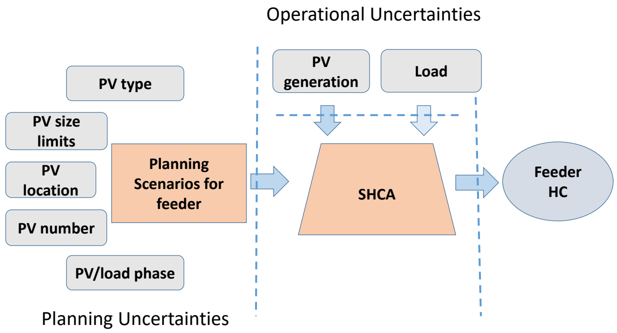

Fig. 1: Decoupling of planning and operational uncertainties to calculate stochastic PV HC using SHCA

in literature use iterative methods of PV scenarios increment, and the use of Monte Carlo based approach makes the computation very expensive. Furthermore, many LV feeders (millions for a small country like Belgium) requiring individual study motivates us to build a faster method.

The uncertainties in LV feeders affecting PV HC can be split into three parts: a) planning, e.g., location, size and type of photovoltaics (PV) installations, b) operational, e.g., load and PV generation and c) feeder, e.g., feeder length, consumer phase. These uncertainties are different, e.g., the operational uncertainties are usually represented by continuous distributions while the planning uncertainties are represented as unknowns [17] (Fig. 1). These uncertainties have to be considered while computing the grid hosting capacity. Furthermore, the operation criteria of LVDS are not very strict, and the grid limits for power quality can be violated momentarily [18]. For LVDS planning problem such as hosting capacity (HC), risk-based stochastic HC calculations enables more informed decision-making [5].

An Stochastic Optimal Power Flow (SOPF) based SHCA is presented in [19], where the planning uncertainties are taken as the decision parameter, and the chance constraints are applied to the voltages and currents in the feeder. The general outline is as follows:

$$\mathrm{HC} = \max \sum_{p \in \mathcal{P}} P_p^{\mathrm{kWp}} \tag{2.1}$$

subject to:

$$\underline{P^{\mathrm{kWp}}} \leq P_p^{\mathrm{kWp}} \leq \overline{\mathrm{P}^{\mathrm{kWp}}} \quad \forall p \in \mathcal{P} \tag{2.2}$$

$$h(x) = 0 \tag{2.3}$$

$$\mathbb{P}(\mathsf{x} \geq x^{\min}) \geq (1-\varepsilon) \tag{2.4}$$

$$\mathbb{P}(\mathsf{x} \leq x^{\max}) \geq (1-\varepsilon) \tag{2.5}$$

The objective is to maximize the total PV installations in a given feeder where each consumer installation p can have ratings between $\underline{P^{\mathrm{kWp}}}$ and $\overline{\mathrm{P}^{\mathrm{kWp}}}$. Equation (2.3) represents Ohm's law and Kirchoff's law forming the power flow equations. Equations (2.4) and (2.5) are the probabilistic chance constraints. The application of chance constraints enforces that the probability of congestion is less than the limit ε.

A polynomial chaos expansion based reformulations are used to convert the chance constraints (2.4) and (2.5) to a linear constraints [20], [21]. SHCA based on polynomial chaos expansion: a) considers the LVDS norms where the voltages or currents limits can be violated for certain instances, b) the planning variables, such as the size of PV, are given as box constraints, and c) the operational uncertainties, i.e., load and PV generations, are represented by known continuous distributions. Furthermore, this method does not rely on sampling, linearization of power flow equations, and iterative deployment of PV, making the solution faster and more accurate than the conventional method. A simple illustration of this method is provided in Fig 1. It is assumed that all consumers can install up to a 15 kWp of PV capacity [19]. For the mathematical details on SOPF based SHCA, readers are pointed to [19].

C. Combination

The MBOPF model gives an economically feasible solar PV for a future scenario, for example, 2030. However, this model uses a simplified power flow and deterministic evaluation. The HC calculated using SHCA is the best PV installation scenario considering the grid constraints only, neglecting the rooftop availability or willingness to invest. To see if the PV installation boundaries obtained from MBOPF require no extra investment in the grid, the box constraints for PV installation size, i.e., $\overline{\mathrm{P}^{\mathrm{kWp}}}$ and $\underline{\mathrm{P}^{\mathrm{kWp}}}$ in (2.2) are replaced by cap^{PV} and 0, and SHCA is performed. Thus obtained PV HC represents the actual PV HC considering both market and grid feasibility.

III. Case Study

We assume costs for 2030 and model an entire year by means of representative days, found as outlined in [22]. All agents are given annualized investment costs. We include four large scale generators, three conventional and one renewable. For large scale generators, we utilize the costs found in [23]. For consumers, the solar PV investment cost is 577 EUR/kW. We arrive at this figure utilizing the learning curve approach based on initial costs found in [24] and learning parameters found in [25]. The perceived solar PV investment cost is rendered heterogenous across consumers by assigning them a random discount rate between 3-6%.

IV. Results and Discussion

A. Total installed solar PV capacity

To evaluate how distributed solar PV integration varies between MBOPF and SHCA, we first take a look at how total installed solar PV capacity differs between the two. The percentage of total solar PV capacity installed in MBOPF, with respect to that installed in SHCA, can be seen in Figure 2, in which mean and standard deviation are also depicted. From the figure, it is possible to see that for the large majority of investigated distribution feeders, the total installed solar PV capacity determined by MBOPF is lower than that found by the SHCA. The SHCA is typically optimistic, and the economic feasibility of installations is the limiting factor regarding the integration of distributed solar PV. Moreover, in four cases, in MBOPF, no consumer decides or finds it beneficial to install solar PV. So while the SHCA is pivotal in providing an upper bound of solar PV capacity, a safety margin that should not be trespassed, in practice, consumer preferences and their willingness to pay for solar PV restricts capacity additions. It is found that, on average, across feeders, 38% of total solar PV capacity installed in SHCA is installed in the MBOPF approach. However, a standard deviation of approximately 30% indicates a significant variance in the observed data. From this, we can conclude that the relative percentage of solar PV capacity is highly feeder specific, and we cannot derive one generalised value.

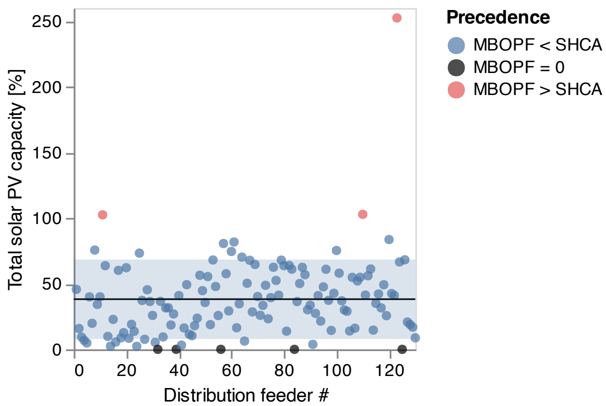

Fig. 2: Percentage of total solar PV capacity installed in MBOPF approach with respect to that installed in SHCA. Line and shaded area illustrate mean and standard deviation and each dot represents an LV feeder.

B. Outlier MBOPF-determined solar PV capacity

For a minority of feeders, three out of all those investigated, total installed solar PV capacity in the market-based approach surpasses that determined by the SHCA. While two feeders have an almost equivalent amount of solar PV capacity across the approaches, one outlier feeder exhibits a total solar PV capacity in the MBOPF method, which is 250% of that found by the SHCA. From this, we learn that the solar PV capacity found using an MBOPF approach is not always guaranteed to be grid feasible. For computational tractability, the predominant method, like ours, when performing an MBOPF, is to utilise a deterministic, linear power flow model. Since such a model cannot consider the stochastic norms and stochastic variables present in distribution grids, failing to capture uncertainties, it may not always present a realistic overview of grid performance in the case of solar PV penetration.

The SHCA using full AC provides an upper limit due to the grid infrastructure, using full AC SOPF. It provides an option to sanity-check the market-based OPF result. This is illustrated with, Figure 3, which presents the normalized, installed solar PV capacity for this outlier case, in which each bar, in total, represents how much capacity is installed per consumer in a market-based approach with shaded regions delineating how much of that capacity is practically feasible. The practically feasible amount is determined by performing the SHCA with box constraints equating the installation size to that found by the MBOPF. As can be seen from the figure, one of the larger installations, found to be economically feasible, needs to be decimated to ensure network operability.

C. Siting of installations

On top of total installed solar PV capacity, an important aspect in evaluating how solar PV integration varies between

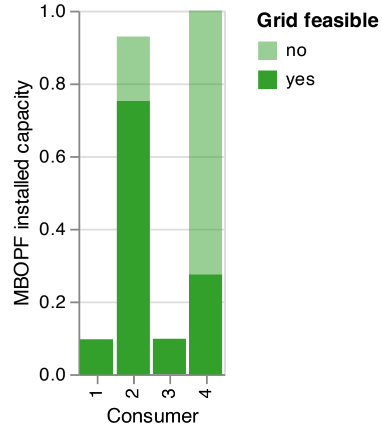

Fig. 3: Normalized, installed solar PV capacity in MBOPF for outlier case where shading denotes the grid feasible amount of capacity.

MBOPF and SHCA is to assess how the siting of individual installations differs. Figure 4 illustrates the percentage of total installation sites across all feeders fulfilled in MBOPF, SHCA, both, and neither. While Figure 5 illustrates the location and size of solar PV installations for one specific feeder. From Figure 4, one can see that 88% of all plausible installation sites are fulfilled in the SHCA. In other words, 88% of consumers own a solar PV installation. We obtain this number by summing the percentages of ‘SHCA only’ and ‘SHCA & MBOPF’. On the other hand, in the MBOPF, only 38.3% of consumers purchase solar PV, derived by summing ‘MBOPF only’ and ‘SHCA & MBOPF’. At the same time, 37% of installations are common across the two approaches. From this, we learn that the economically feasible sites are much fewer than the purely technically feasible ones and that the SHCA is able to capture most of the economically feasible sites based on the fact that it finds so many sites feasible. Moreover, if we look in more detail at the locations where solar PV is installed, by observing Figure 5, we note that in the SHCA, solar PV will be installed and concentrated closer to the transformer, while no installations are present at the end of the feeder. This is due to the fact that in SHCA, PV installations are placed at the most practically favourable locations, i.e., near the distribution transformer, as the installations further down the feeder are more likely to induce over-voltage events. On the other hand, this is not the case in the MBOPF, which, while accounting for the network’s operational limits, may find that an economically beneficial location for installing solar PV, is indeed, at the end of the feeder.

V. Conclusion

In this paper, we compare the technical and economic limits of solar PV integration across 130 LV European distribution feeders. The economic PV installations are derived through an MBOPF considering active and reactive power trading and in which all consumers may invest in solar PV capacity. The modelling approach allows feedback between consumer decisions, electricity prices and the wider energy system. The technical limit is evaluated using an SHCA that considers uncertainties in the load and irradiance and chance constraints in the voltages and thermal loading.

From the findings, we derive three main conclusions.

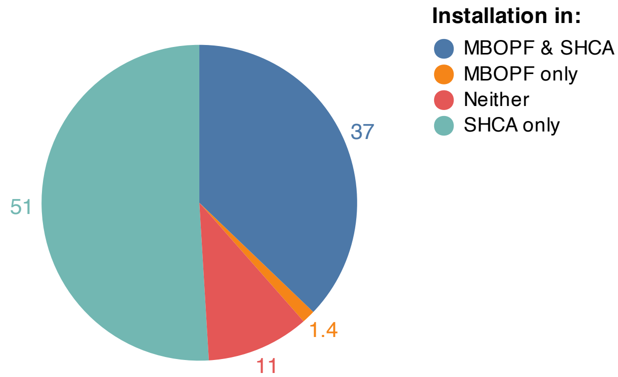

Fig. 4: Percentage of total installation sites, across all feeders, fulfilled in MBOPF, SHCA, both, and neither.

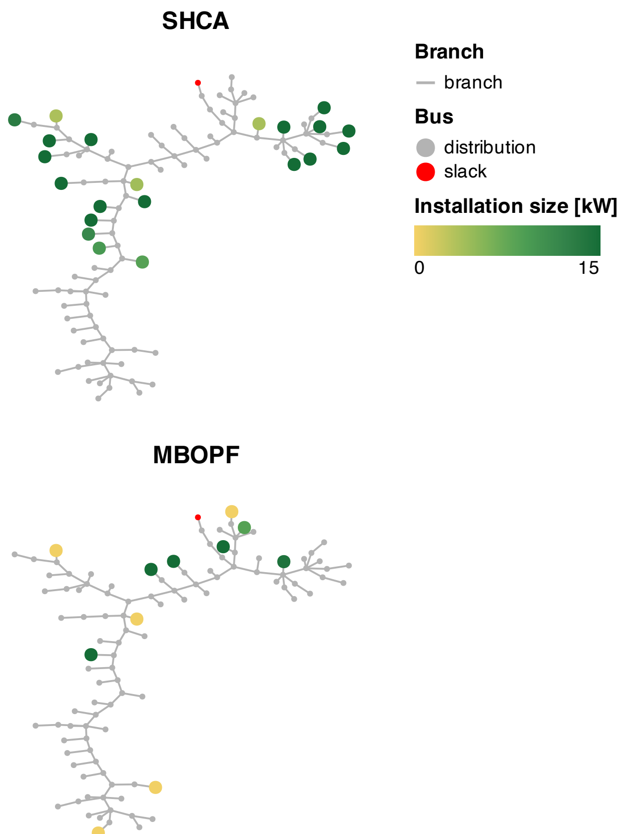

Fig. 5: Location and size of solar PV installations in SHCA and MBOPF.

Firstly, the technical limit for solar PV integration is overly optimistic, as the total solar PV capacity found by MBOPF, considering the economic feasibility of installations, precedes the technical threshold. On average, across feeders, only 38% of the total solar PV capacity found in the SCHA is installed in MBOPF. However, a large variation points out that the proximity of technical and economic limits is highly feeder specific. Secondly, we learn that deterministic, linear power flow utilised in MBOPF approaches is not a foolproof method for assessing how much solar PV capacity can be safely integrated into distribution systems. Lastly, we note that economically feasible installation sites are much fewer than technically feasible. Moreover, SHCA tends to favour concentrating installations at the beginning of the feeder, in order to minimize voltage rise, overlooking the fact that consumers at the end of a feeder may have a high willingness to pay for solar PV.

Overall, our analysis allows decision makers to understand how economic factors, beyond the purely technical value of hosting capacity, also pose a cap on the amount of solar PV capacity that can be integrated into LVDS. The future work will aim at integrating socio-economic factors, land/rooftop availability, and other non-financial drivers of investment in calculating the hosting capacity of the distribution systems.

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