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Hosting Capacity Estimation for Behind-the-meter Distributed Generation

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***Abstract*— Power utilities worldwide are facing a growing number of customers' requests to authorize the interconnection of behind-the-meter distributed generation.**

This paper presents a new practical methodology for power utilities to estimate the amount of small-scale distributed generation they can accommodate in the low-voltage level of distribution feeders without potential harm to the latter. It considers both medium-voltage and low-voltage levels limiting criteria to determine the locational hosting capacities.

The proposed method uses detailed models of distribution feeders extracted from the geographical information system of power utilities and the location of existing customers. A new tool based on the proposed methodology is also described in the paper to show how the methodology can be easily integrated into existing planning tools of power utilities. It reports the circuits' total hosting capacity and provides hosting capacity maps with results per medium-voltage feeder section, distribution transformer, and low-voltage system. Results for real large-scale distribution feeder models demonstrate the practicality and potential of this methodology.

Index Terms—Behind-the-meter, distributed generation, distribution systems, geographical information system, locational hosting capacity, planning, software development.

I. INTRODUCTION

The adoption of behind-the-meter Distributed Generation (DG) has increased in the last twenty years thanks to energy policy changes, technology improvements, cost reductions, and the rising interest of final users in producing electricity [1].

High penetration levels of DG impact the distribution system in terms of voltage rise and unbalance [2], [3], voltage fluctuations [4], short-circuit currents [5], and reverse power flows [6], among others.

Voltage rise above the statutory limits can damage customer appliances. Furthermore, voltage fluctuations may accelerate the wear and tear of load tap changers and line Voltage Regulators (VRs) [7], and rapid fluctuations may lead to flicker. Changes in short-circuit currents can affect the coordination and selectivity of overcurrent protection devices [8], whereas reverse power flows may disturb the proper operation of VRs and exceed the ampacity of conductors and the rating of transformers.

Some utilities have prevented such problems by limiting the feeder's DG capacity installation according to conservative thumb-based rules [9]. For example, several utilities around the world have limited the DG capacity installations to 15% of the feeder's annual peak load. However, this rule ignores the unique characteristics of each feeder and the scattered installations of small-scale DG units in many Low-Voltage (LV) systems. This restrictive measure has mitigated most operational risks at the expense of many customers not being allowed to connect their projects, no matter the size or minimal impact on the system. As the DG installed capacity grows, regulatory agencies in several jurisdictions have requested power utilities to determine how much capacity can be added to feeders before they reach conditions that reduce service quality and reliability. This includes publishing feeder maps with information about sections with availability to connect more DG and spots where no more DG can be authorized.

The term Hosting Capacity (HC) refers to the maximum amount of DG capacity that can be accommodated without compromising the operation, reliability, and power quality of the Distribution Network (DN) [9] [10].

The HC estimation methods rely on computer simulations of DNs models to evaluate power-quality related problems, system protection performance, and equipment overloading at different penetration levels of DG units [11]. These calculations estimate how much power can be installed without requiring major changes to the distribution system.

Dynamic Thermal Rating (DTR) systems [12], volt/var control [13], and active power curtailment [14] are known measures to improve power quality and system reliability in the presence of high DG penetration levels. However, these corrective actions are generally not considered when estimating the HC, as power utilities generally remain conservative during the planning stage.

According to [11], the HC estimation method should be scalable to large networks, clear regarding what is calculated, and repeatable to consider individual feeder modifications. Also, it should be available such that readily accessible data and distribution planning tools can be utilized.

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The HC estimations can be classified into deterministic, stochastic, optimization-based, and streamlined methods [15]. In the deterministic method, the DG production and location information are defined before the start of the HC calculation. As the randomness of load and DG is not considered, worst-case scenarios are commonly used in deterministic methods. The advantage of stochastic methods is that they can account for uncertainty [16]. However, the results are generally difficult to interpret and cannot be easily included in HC maps for the public. Moreover, the computational requirements often limit the application to small-scale distribution systems only. Optimization-based methods maximize the active power injection of DGs subject to the distribution network's operational limits. However, due to model complexities, network simplifications are generally used, which affects the accuracy of results. Finally, the streamlined methods rely on heuristics to speed up the evaluation process, but they do not consider the impact of DG in LV systems [11].

Reference [17] presents a Monte Carlo-based method to estimate the HC of distribution systems. The need of thousands of scenarios increases the computational burden and hinders the creation of HC maps. More recently, the work in [18] proposes an optimization-based HC analysis for active distribution systems. Despite the simplifications of the network model and size to fit in the optimization formulation, it is time-consuming and impractical for large-scale feeders with single- or two-phase laterals and split-phase LV systems. Similarly, the authors in [19] propose an optimal power flow formulation to estimate the HC with multitype distributed energy resources, only validated in small test systems.

The work in [20] proposes a possibilistic evaluation of large-scale DG hosting capacity under uncertainty. The authors in [21] present an HC calculation with correlated uncertainties and large-scale units. The work in [22] presents a method to compute HC with photovoltaic generation in the presence of electric vehicles. However, these methods are only validated in small test feeders and consider simplified network models.

Most HC methodologies that use real distribution system models focus on the HC of DG units at Medium-Voltage (MV) levels [11]. However, LV systems with dozens of customers cannot be overlooked, as they will also limit the amount of behind-the-meter DG that can be accommodated. While some research has studied the HC in individual LV systems [9], they do not simultaneously evaluate the HC with multiple LV systems and the upstream MV level.

HC methods applied to real distribution systems call for detailed network models and more practical methods, mainly when dealing with small-scale DG units. Moreover, the power utilities need methodologies that can result in HC maps to share with the public.

This paper presents a practical methodology for power utilities to estimate the HC for behind-the-meter generation while considering MV and LV limiting criteria. The article summarizes the work and software tool developed by the Electric Power and Energy Research Laboratory at the University of Costa Rica for The Costa Rican Institute of Electricity, a vertically integrated public utility in the country.

The proposed HC method uses detailed MV and LV systems information readily available in the Geographical Information System (GIS) of power utilities. The location and energy consumption of the existing customers is considered for identifying the potential hotspots where behind-the-meter DG needs to be limited. This method allows power utilities to compute the locational HC for small-scale units explicitly modeled in large-scale feeders. Therefore, it tracks down the limiting criterion that constrained the HC in each LV system and MV section. Power utilities can quickly identify network reinforcements or control actions to increase the locational HC when needed.

The methodology results in colored HC maps that report the feeder locations with the capacity to accommodate future DG units of the existing customers. Power utilities obliged to publish and update their HC maps will benefit from this approach.

The contributions of this paper are:

- A new practical methodology to estimate the HC for behind-the-meter DG that considers distribution systems' MV and LV levels. This allows evaluating the interactions between voltage levels and how DGs in one secondary system can affect and limit the HC of nearby secondaries.
- Evaluation of the proposed methodology in four large-scale feeders. The HC estimations rely on detailed network models extracted from the GIS of power utilities.
- A comparison of the HC results considering a) realistic allocation of behind-the-meter DGs based on the location and demand of existing customers in the secondary systems, b) all DGs lumped at the beginning of LV systems, and c) all DGs connected at the far end of the LV systems.

The remainder of this paper is organized as follows: Section II presents the proposed methodology with all the limiting criteria for the MV and LV levels. Section III introduces the developed tool to estimate the HC, and Section IV presents numerical results in several distribution feeder models. The concluding remarks are finally presented in Section V.

II. Methodology for HC estimation

The proposed methodology evaluates limiting criteria in both the MV and LV levels of the distribution system. An initial power flow and short-circuit calculation are carried out for the actual network conditions. This corresponds to the base case. Then, a cumulative DG installed capacity is increased by an established step and distributed among MV and LV nodes in the feeder. Power-flow and short-circuit calculations are carried out for each installed capacity, and the results are compared against those of the base case.

The iterative procedure stops when all the MV nodes have reached their locational hosting capacities, when the MV assets or LV nodes present an evaluation criterion violation, or when the maximum DG cumulative installed capacity, defined by the user, is reached.

A. Limiting Criteria

The limiting criteria relate to a set of operating characteristics in the distribution feeder affected by the integration of DG. The restrictions must comply with local regulations for the safe and reliable operation of the system.

The limiting criteria for the proposed HC estimation methodology were classified into voltage, thermal, and protection device constraints.

1) Voltage Constraints

- Overvoltage: since the increase of active power generation may lead to voltage rise conditions [23], the voltage magnitude in all nodes must remain below a threshold value to guarantee safe power delivery. This threshold depends on local regulations, taking a typical value of 1.05 p.u. [24].
- Voltage Deviation: the voltage magnitude in any node should not vary more than a threshold percentage with respect to the base case without DG [25]. This percentage is defined as 3% for MV nodes and 5% for LV nodes.
- Voltage Unbalance: since most DG units are installed in single-phase LV systems, voltage unbalance in three-phase nodes must be checked. Voltage unbalance is computed as the ratio of the negative sequence component to the positive sequence component, in percentage [26]. To ensure a safe operation, the unbalance must remain below an established threshold, which typically takes a value of 3% [27].

2) Thermal Constraints

Reverse power flows due to high penetration levels of DG units may result in overloading conditions of transformers, overhead lines, and underground cables. The static thermal constraints ensure that no power delivery element will exceed its ampacity.

3) Protection Devices Constraints

- Reduction of Reach: due to the presence of short-circuit current sources between an upstream protection device and the downstream fault location, the short-circuit current sensed by the protection device could be reduced. This may prevent or delay the activation of the protection device when needed. To avoid this, any short-circuit current sensed by any protection device in the presence of DG should not exceed a 10% reduction compared to the base case [28]. The fault is evaluated at the node furthest away from the protection device, within its operating zone.
- Forward Fault-Current Increase: when downstream faults occur close to the protection device, the fault current experienced by the protection device is increased by the upstream DG's fault contribution. This could cause a malfunctioning of the protection device. To avoid such eventuality, the increase in fault current compared to the base case must remain below a certain percentage. It is often recommended to keep such an increase below 10% [28]. The fault is evaluated in the closest node downstream of the protection device.
- Sympathetic Breaker Tripping: when two or more distribution feeders are fed by the same source (substation), sympathetic tripping in one DG-populated feeder can occur due to the fault-current contributions from DGs during a fault in an adjacent feeder [29]. To avoid this, the currents sensed at the feeder's head shall not exceed the pick-up currents of the corresponding protective device for faults simulated at the end of a short (100-m long) MV line connected to the substation [30]. This evaluates the near-worst-case scenario, where the fault current coming from the DG-populated feeder is highest.
- Breaker-Fuse Coordination: this criterion intends to keep the feeder's fuse-saving coordination scheme. The latter may be lost when the passing fault current in the fuse increases significantly while the breaker does not perceive it (due to fault current contributions from DG in between the devices). The criterion limits the difference between the increase in the currents seen by the fuse and the breaker in presence of DG. This value is often suggested to be 100 A [28]. The fault is simulated in the closest node downstream from the fuse, within its operating zone. During the fault evaluation, the currents in the fuse and the breaker are monitored.

B. DG sizing and allocation in the MV nodes

The proposed methodology assumes a customer-based DG allocation, i.e., the higher the customer demand and density, the higher the probability of having future behind-the-meter DG.

The load distribution along the feeder is known, and it fully depends on the power demand and location of each customer. Thanks to the detailed customer-based DG allocation, the method allows for a simple-to-implement HC evaluation that follows the most probable DG installations along the MV nodes and down to each LV node, as explained in section II-C.

Figure 1 depicts the DG sizing and allocation for the *n* MV nodes in the feeder at each iteration. The allocation is based on the actual power demand at each node. The nodes with higher demand will have higher installed DG capacity. Note that the sum of all MV nodes' installed capacity equals the cumulative installed capacity.

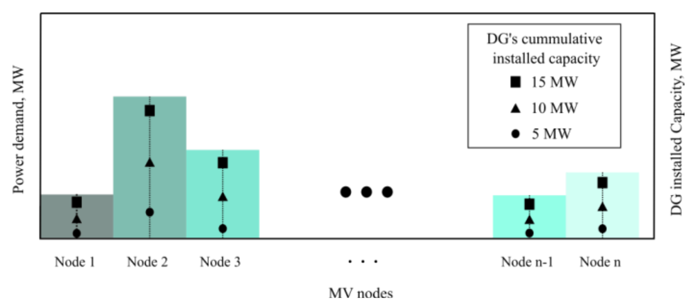

Fig. 1. Example of a loading distribution in a distribution feeder and its corresponding DG sizing allocation.

The percentage of the cumulative DG capacity to allocate at MV node i, $\%P_i^{DG}$, is calculated based on the ratio of the node's demand P_i and the total feeder demand P_D, as follows:

$$\%P_i^{DG} = \frac{P_i}{P_D} \cdot 100 \quad (1)$$

At iteration k, the additional DG capacity $\Delta P_i^{(k)}$ to allocate at MV node i is calculated as:

$$\Delta P_i^{(k)} = \%P_i^{DG} \cdot \Delta P_{DG}^{(k)} \quad (2)$$

where $\Delta P_{DG}^{(k)}$ is the total additional DG capacity to allocate in the feeder, and it is computed as:

$$\Delta P_{DG}^{(k)} = \frac{\Delta P_{i,max}^{DG}}{\%P_{max}^{DG}} \quad (3)$$

Here, $\Delta P_{i,max}^{DG}$ is an input parameter in kW, defined to control the step size of the cumulative capacity per iteration for node i, and $\%P_{max}^{DG}$ is obtained from (1) for the MV node with the biggest demand in the feeder.

At iteration k, the cumulative installed capacity in the distribution feeder is:

$$P_{DG}^{(k)} = P_{DG}^{(k-1)} + \Delta P_{DG}^{(k)} \quad (4)$$

Finally, the cumulative installed DG capacity at node i during the k_{th} iteration is obtained as:

$$P_{iDG}^{(k)} = P_{iDG}^{(k-1)} + \Delta P_{i}^{(k)} \quad (5)$$

C. DG sizing and allocation in the LV nodes

The installed capacity $P_{iDG}^{(k)}$ must be distributed among the downstream LV nodes fed from MV node i.

The DG size and allocation in LV nodes also depend on the load distribution in the LV branch (secondary system). The capacity allocation is done in the same way as for the MV nodes, with equivalent equations (1) and (2) for the LV nodes, considering that the cumulative DG capacity in the LV branch corresponds to $P_{iDG}^{(k)}$ of the upstream MV node.

The percentage of DG capacity to allocate at LV node j $\%P_j^{DG}$ is calculated based on the ratio of each node's demand P_j and the total demand of the LV branch P_{LVD}:

$$\%P_j^{DG} = \frac{P_j}{P_{LVD}} \cdot 100 \quad (6)$$

At iteration k, the additional DG capacity $\Delta P_j^{(k)}$ to allocate at LV node j, related to the upstream i_{th} MV node is calculated as:

$$\Delta P_j^{(k)} = \%P_j^{DG} \cdot \Delta P_i^{(k)} \quad (7)$$

Note that the DG sizing and allocation in the LV nodes is coupled to the same process performed for the MV nodes only by how much DG must be distributed ($\Delta P_i^{(k)}$). Otherwise, the process is completely independent and relies solely on the characteristics of the load and its distribution in the LV branch, characterized by P_{LVD} and P_j.

D. Treatment of violations in LV and MV levels

When at least one thermal or voltage criterion is violated in one LV branch, all the nodes of this secondary system, including the upstream MV node, will be reported and removed from the pool of available nodes for more DG installations. This is done while maintaining their last maximum installed DG capacity without criteria violations, i.e., their locational HC. Note that the methodology is designed to build up the HC of the feeder from the detailed analysis of each LV branch, which allows for a much clearer understanding of the limits of DG in each feeder.

The additions of DG capacity in the feeder for the following iterations steps require a redistribution of the percentages found in (1). This is done by excluding the demand of the reported MV node in the computation of P_D.

Figure 2 illustrates the above-mentioned situation for a simplified distribution feeder with five MV nodes and the corresponding LV branches. For a given installed capacity in the MV and LV nodes, it is found that branch LV_4 presents at least one voltage or thermal limit violation. Based on this, all the nodes in LV_4 and node MV_4 will no longer be candidates for accommodating more DG capacity. Therefore, the reported node MV_4, and those in LV_4, will keep the last installed capacity before the violation was encountered. The remaining four MV nodes, and the corresponding LV systems, are the only candidates to accommodate additional DG capacities.

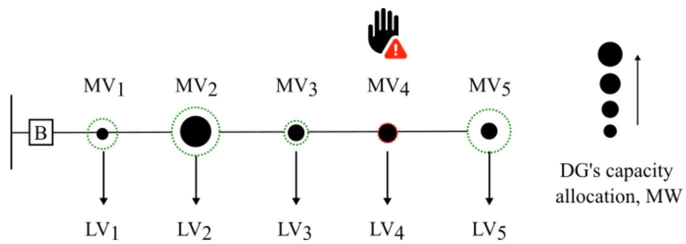

Fig. 2. Illustration of LV branch and corresponding MV node reaching its DG hosting capacity at a given iteration step.

For the subsequent iterations, the evaluation criteria must still consider the reported MV nodes and the corresponding secondary systems. If a new violation is found in one of these unavailable nodes, due to DGs installed in other parts of the feeder, the iterative procedure must stop, as higher DG penetration levels are likely to cause unacceptable conditions in these secondary systems. The feeder's HC is the last allocated DG capacity that did not trigger any violation.

As for the MV level, if one or more voltage, thermal or protection-related violations are found at iteration k, the procedure must stop, meaning that the previous capacity value allocated in the feeder, $P_{DG}^{(k-1)}$, is the actual HC limited at MV level. Similarly, the locational HC at MV node i will be the one reported in $P_{iDG}^{(k-1)}$.

For better understanding of the proposed methodology, Fig. 3 shows a flow chart that describes its sequence of execution, inputs, and outputs.

The methodology allows including the existing or planned large-scale DG projects. These projects are more easily trackable for network operators, which facilitates including them in the HC assessments if needed.

The proposed methodology is practical, it relies on data that is owned by and readily available to power utilities, and it can be easily integrated into existing planning tools of power utilities.

III. HC ESTIMATION TOOL

A new tool called Integration of Distributed Energy Resources (IDER) was developed to facilitate the HC calculation for distribution feeders. The tool is part of a GIS software integrated with *OpenDSS*. The latter is an open-source software developed by EPRI [31] that models and simulates distribution feeders.

The new tool can incorporate DG elements into the circuit model, allowing the creation and analysis of different possible scenarios, including different penetration levels of DG. Researchers, power utilities and third parties can download, use, and modify the tool available in the Github repository [32] to estimate the HC in their feeders. The following sections explain the data requirements and the output results.

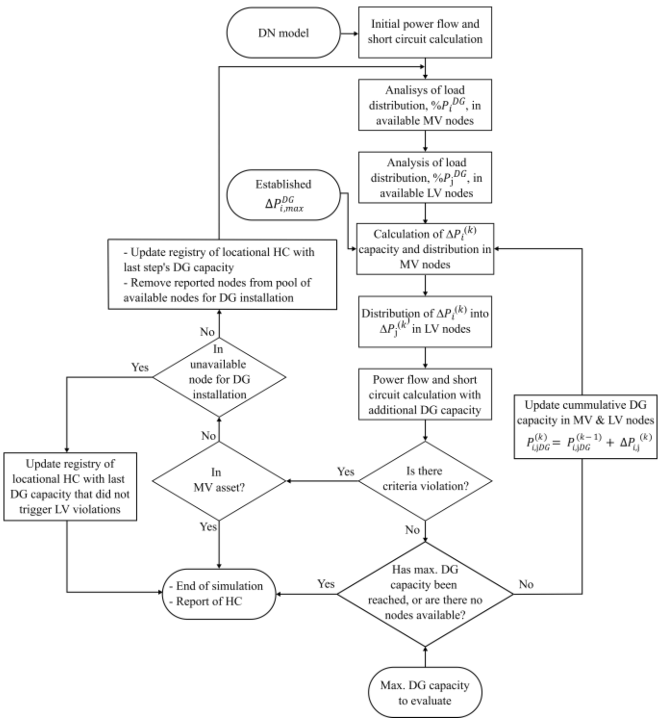

Fig. 3.. Flow chart of the methodology for calculating the hosting capacity of DG in DN.

Power utilities commonly use GIS databases to store and manage georeferenced information of all the available assets connected to the distribution system [33]. One popular open-source software to collect GIS information is *Quantum GIS* (QGIS). Since QGIS is equipped with a Python programming language console, it is possible to link QGIS with other software through Python. This promotes the development of plugins to manipulate the GIS data directly in QGIS.

The *IDER* tool uses the plugin *QGIS2OpenDSS*, introduced in [34], to build a distribution system model in *OpenDSS* from the GIS data. Then, it runs simulations for each DG penetration level and selected locations to estimate the HC of the distribution feeder, using the method presented in Section II.

A. GIS Data Requirements

Besides the data requirements specified in [34] for the *QGIS2OpenDSS* tool, the following data is required to perform the HC analysis:

- *Large-Scale Distributed Generators (LSDG):* This information shall be provided in the presence of generators connected to the MV via a distribution transformer. When applicable, it is represented as a GIS layer of points, whose attributes must include kVA or MVA ratings, nominal voltage level, and the transient and subtransient reactances of the large-scale DG units, when applicable.
- *Small-Scale Distributed Generation (SSDG):* The SSDG layer is exclusively for existing DG units connected to the LV system. The required attributes are the same as those for the LSDG layer, except for the transient and subtransient reactances that do not apply to non-rotating generators.
- *Reclosers:* This layer only requires the location and expected state of the recloser, whether it is normally open (NO) or normally closed (NC).
- *Fuses:* This layer must include the location of all fuses, and the normal state of the fuse.
- *Switches:* This layer only requires the location and expected state of the switches.

B. Input data

Figure 4 shows the GUI for the *IDER* tool as a plugin in QGIS. The user must define the path of the *.csv* file that contains the feeder's annual curve demand. Then, the user must specify the desired day and hour to simulate. The day may be chosen as a typical one or for minimal or maximal demand conditions.

The user must define the maximum capacity $P_{DG,max}$ to stop the simulation, see Fig. 3. The value must be large enough to allow for finding the actual feeder's hosting capacity.

The user must also define the maximum capacity increase per iteration step, $\Delta P_{i,max}^{DG}$ in (3), for nodes with MV loads directly connected to them and MV nodes that feed LV systems. The former usually have larger hosting capacities than the latter.

The user may also limit the installed capacity in LV circuits to be no larger than the upstream MV/LV transformers' capacity. This is, the LV system will not be a candidate for hosting more DG capacity as soon as its allocated capacity reaches the transformer's nameplate capacity. The use of this limiting criterion depends on local regulations.

Finally, the user must also define the DG contribution to fault currents (FC) as a percentage of the DG's nominal capacities.

The *IDER* tool lets the user decide on the combination of evaluation criteria in the HC analysis. The tool has the following input requirements:

- *Inputs for Protection Devices Criteria:*
  - *Fault types:*
    Type of faults to consider in the evaluation of the protection devices criteria. The letters A, B, and C are used to specify the involved faulty phases, and the letter G denotes phase-to-ground faults.
  - *Forward Fault Current Increase:*
    Maximum percentage of fault current increment in the adjacent bus to the protection device, as compared to the base case.
  - *Sympathetic Tripping:*
    Phase and ground pick-up current setting for the main feeder's circuit breaker.
  - *Breaker-Fuse Coordination:*
    Maximum difference allowed between the fault current increment in fuses and the fault current increment in reclosers.
  - *Reduction of Reach:*
    Maximum percentage of fault current reduction allowed in the farthest node of the correspondent protection device's sensing zone.

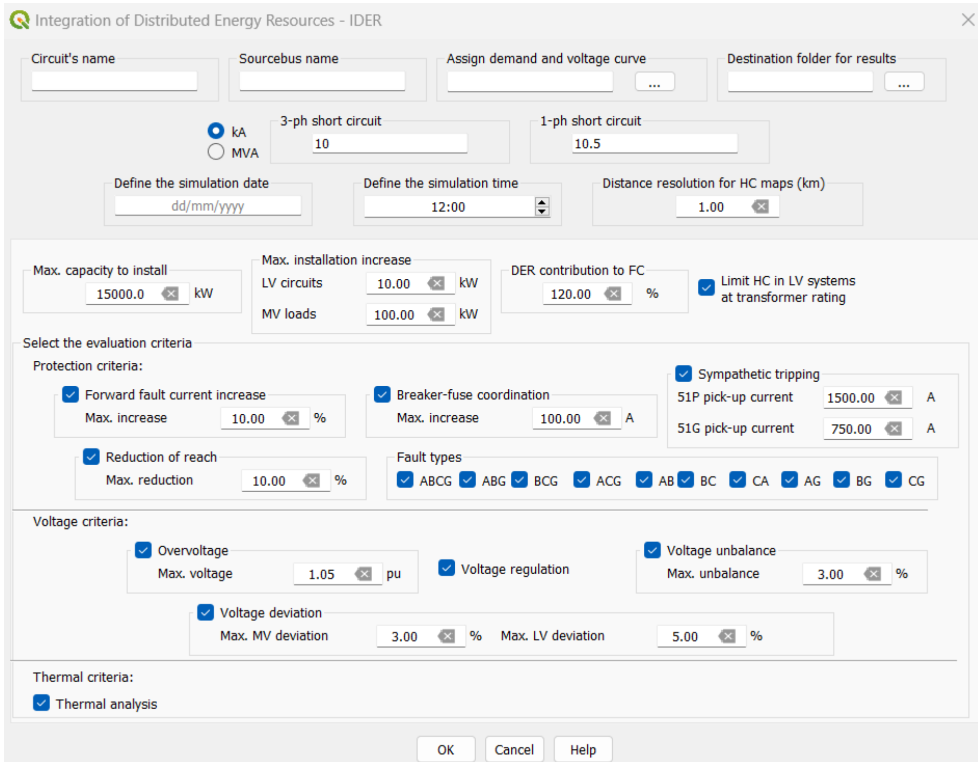

Fig. 4. Graphical User Interface (GUI) of IDER tool.

- *Inputs for Voltage Criteria:*
  - *Overvoltage:*
    Maximum voltage level allowed for all buses in the circuit, in per unit.
  - *Voltage Deviation:*
    Maximum percentage of bus voltage difference between the simulated case and the base case without DG. The user can define different values for MV and LV buses.
  - *Voltage Unbalance*:
    Maximum allowed ratio of the negative and positive-sequence voltage in three-phase buses, in percentage.

Thermal criteria evaluation does not require input data since the tool reads and uses the rated power of transformers and the ampacity of cables and overhead lines, as defined in the *OpenDSS* model.

C. HC Results

The tool can be customized depending on the user's needs. The user may include all the limiting criteria described in Section II.A. However, the user can also choose to run the HC estimation with less limiting criteria. By doing so, the utility can identify the bottlenecks for voltage, thermal, and protection criteria independently. This information is useful to identify future network investments to increase the existing HC. Additionally, the tool provides a visual representation of the locational HC along the feeder's topology. For this, the feeder is divided into three-phase MV sections whose distance is defined by the user in the "distance resolution for HC maps (km)" box.

The HC for each section results from the aggregation of all DG capacities that belong to this section. Since the proposed methodology allocates DG based on the location of existing customers in the feeder, low HC are expected in sections with little or no loads.

The information provided by the HC-estimation tool includes:

- Locational HC for MV/LV transformers and LV systems.
- The limiting criterion that constrained the HC in each MV/LV transformer and LV system.
- The limiting criterion that constrained the HC at MV level (when the simulation stopped before all locational HC were found).
- HC in three-phase MV feeder sections, which results from aggregating the corresponding locational HC.

IV. CASE STUDY: HOSTING CAPACITY ESTIMATION

The proposed methodology was used to estimate the HC of behind-the-meter DG in four real distribution feeder models provided by four independent power utilities from Costa Rica.

A. Description of Distribution Feeders

The feeders are in semi-urban areas, and they serve mostly residential customers. In this paper, they are labeled as feeders 1, 2, 3 & 4.

Table I summarizes the main feeder characteristics. These feeders are radially operated, with a nominal voltage of 34.5 kV at the MV level, and nominal voltage of 120/240 V for most LV systems. The three-wire LV systems are fed by single-phase split-phase MV/LV transformers. The ratings of these transformers range from 15 to 100 kVA, with 37.5 and 50 kVA being the most common. Three-phase transformers are also present for commercial and industrial customers, but they are a minority.

Table I
GENERAL CHARACTERISTICS OF DISTRIBUTION FEEDERS.

Characteristic	Distribution Feeder 1	2	3	4
Length, km	23.5	13.0	16.0	7.5
Nominal voltage, kV	34.5	34.5	34.5	34.5
Peak load, MW	9.6	17.2	10.1	13.4
MV/LV transformers	518	447	568	972
Costumers served	10153	13321	16168	20526
Large-scale DG	Yes	No	No	No

The feeders serve between 10,000+ and 20,000+ customers, and the lengths range from 7.5 km to 23.5 km. Feeders 1 and 4 present the lowest and highest density of customers, respectively.

The diversity of load demands, feeder lengths, and the number of consumers allow for a rich evaluation and validation of the proposed method.

B. Numerical Results

This section presents the HC results for the analyzed feeders. Table II summarizes the input parameters used in the simulation tool. The voltage unbalance criterion applies to three-phase buses only. Moreover, the short-circuit calculations for the protection device criteria included all fault types. However, the sympathetic tripping limiting criterion was not evaluated.

Table II
INPUT PARAMETERS AND LIMITING CRITERIA FOR ALL FEEDERS.

Parameter/Limit	Value
Max. overvoltage	1.05 p.u.
Max. voltage dev. in LV	5%
Max. voltage dev. in MV	3%
Max. voltage unbalance	3%
Max. line loading	100%
Max. transformer load.	100%
Fault-current increase	10%
Breaker/Fuse Coord.	100 A
Max. reduction of reach	10%
$\Delta P_{i,max}^{DG}$	5 kW
$P_{DG,max}$	15 MW
Resolution for HC maps	1 km
DG's FC contribution	120%

For the short-circuit studies, the existing large-scale synchronous machine in feeder 1 was modeled as a voltage source behind the transient reactance, whereas the behind-the-meter DGs were modeled as constant power current-limited generators [30]. The fault-current contribution of small-scale DGs was assumed 120% of the rated current [35]. They were represented in *OpenDSS* as generators with model 7 [30], [36].

The HC was estimated for all evaluation criteria considered at once, i.e., voltage, thermal, and protection criteria. However, the voltage criteria were the most restrictive. The estimated HC for feeder 1 is 2.76 MW, and the stopping criterion was the voltage deviation higher than 5% in previously reported secondary systems.

Figure 5 presents the expected voltage deviations in all LV nodes of feeder 1 for a DG installation of 2.76 MW, i.e., the estimated HC. Note that all secondary systems keep a voltage deviation lower than 5%, i.e., comply with the evaluation criterion. The LV nodes with potential voltage deviation problems are mostly located at the far end of the secondary systems.

Figure 6 presents the voltage profile in feeder 1 for a DG installation of 2.76 MW. The apparent vertical lines are formed by the LV nodes that belong to the same secondary. Note that none of the MV or LV nodes reach a voltage of 1.05 p.u.

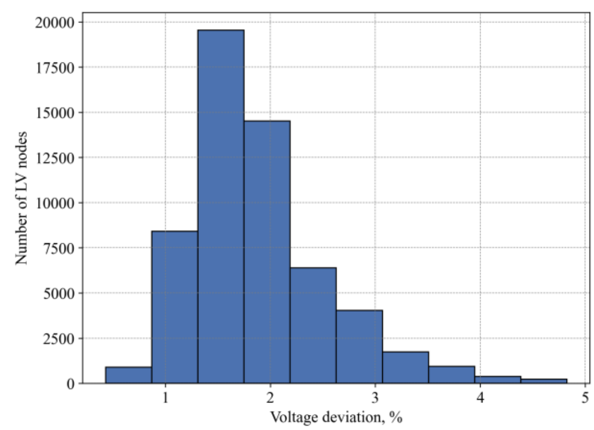

Fig. 5. Histogram of voltage deviation for the HC result in feeder 1.

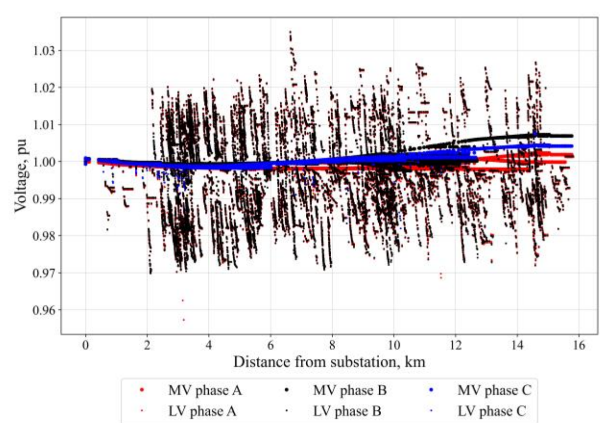

Fig. 6. Voltage profile for HC result in feeder 1.

Figure 7 shows the HC map for feeder 1 with a 1-km resolution. Only the three-phase MV sections are shown. This map results from the summation of all DG capacities that belong to the same 1-km feeder section. Figure 8 shows the actual location of the existing customers in the feeder. Note that the HC distribution depends on the location of the existing customers.

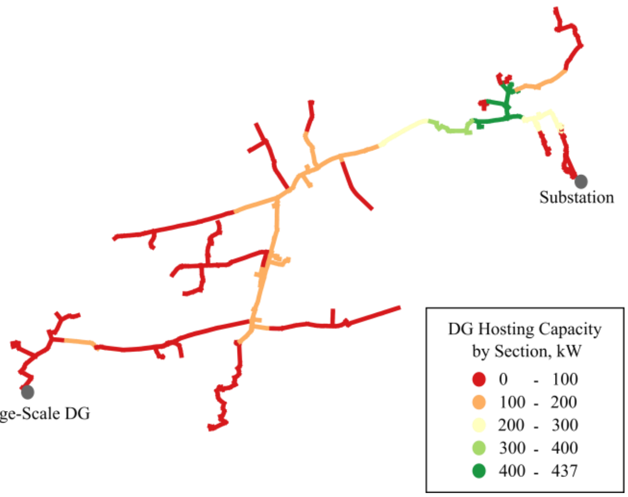

Fig. 7. HC estimation results for feeder 1, considering voltage, thermal and protection limiting criteria.

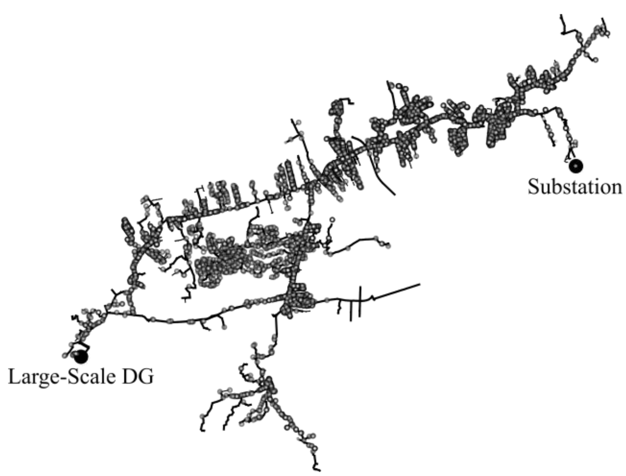

Fig. 8. Location of customers in feeder 1.

From the HC maps in Fig. 7 and customer locations in Fig. 8, it is possible to analyze the relationship of the HC on each LV system with distance from the substation and the respective load density (customers/km).

Figure 9 shows the local HC in all secondary (LV) systems of feeder 1, with a 1-km resolution for calculating the load density. The red circles identify the secondary systems that were reported in the iterative process as unavailable for hosting more DG due to potential voltage-deviation problems. These secondaries were found in high-load density zones (+500 customers/km). Moreover, there were no voltage problems in low-load density zones. Note that some LV systems situated more than 6 km from the substation may host more DG than others close to it. The local HC depends on the length of each secondary system, the transformer rating, and the number and distribution of customers in each LV system.

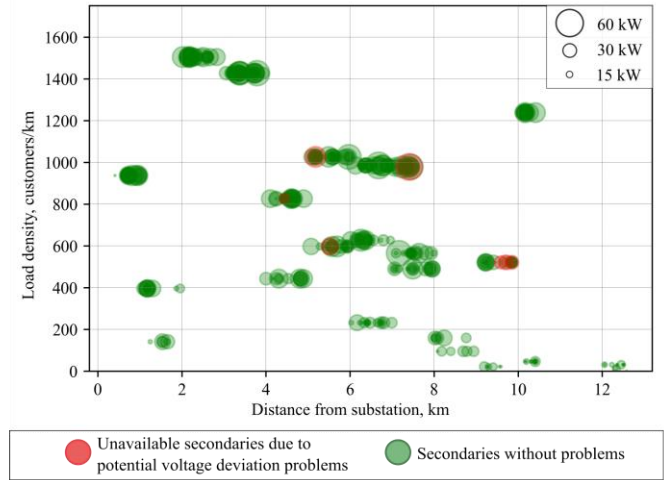

Fig. 9. Comparison of secondary systems' HC based on distance from the substation and load density. The size of the circles represents the local HC

The proposed methodology has the advantage of reporting the HC at each transformer and the corresponding LV system. For example, Fig. 10 shows the estimated locational HC in feeder 1 for each transformer and LV system. This map can be made publicly available to report the neighborhoods that can allocate behind-the-meter DG.

A similar study was carried out for feeders 2, 3, and 4 when evaluating the three limiting criteria at once. The HC results are summarized in Table III. Feeder 2 reached a total HC of 7.28 MW. The stopping criterion was the voltage deviation larger than 5% in a reported (unavailable) secondary system due to the DG installation in other feeder sections. Similarly, feeder 3 reported an HC of 3.76 MW. Finally, feeder 4 has an HC of 5.45 MW. The HC was also limited by voltage-deviation violations in reported secondary systems. Therefore, no more DG capacity could be accommodated in these feeders.

The computation times and the number of iterations are also presented in Table III. Feeder 1 required 75 minutes to obtain the HC result after 10 iterations, while feeders 2, 3, and 4 took 51 minutes (17 iterations), 157 minutes (10 iterations), and 53 minutes (10 iterations), respectively. The simulations were performed in an Intel(R) Xeon CPU E5-2620, 64 GB RAM, and 2.10 GHz processor.

Table III
SUMMARY OF HC ESTIMATION RESULTS FOR FEEDERS 1 TO 4.

Feeder	HC, in MW	Number of iterations	Computing times in min.
1	2.76	10	75
2	7.28	17	51
3	3.76	10	157
4	5.45	10	53

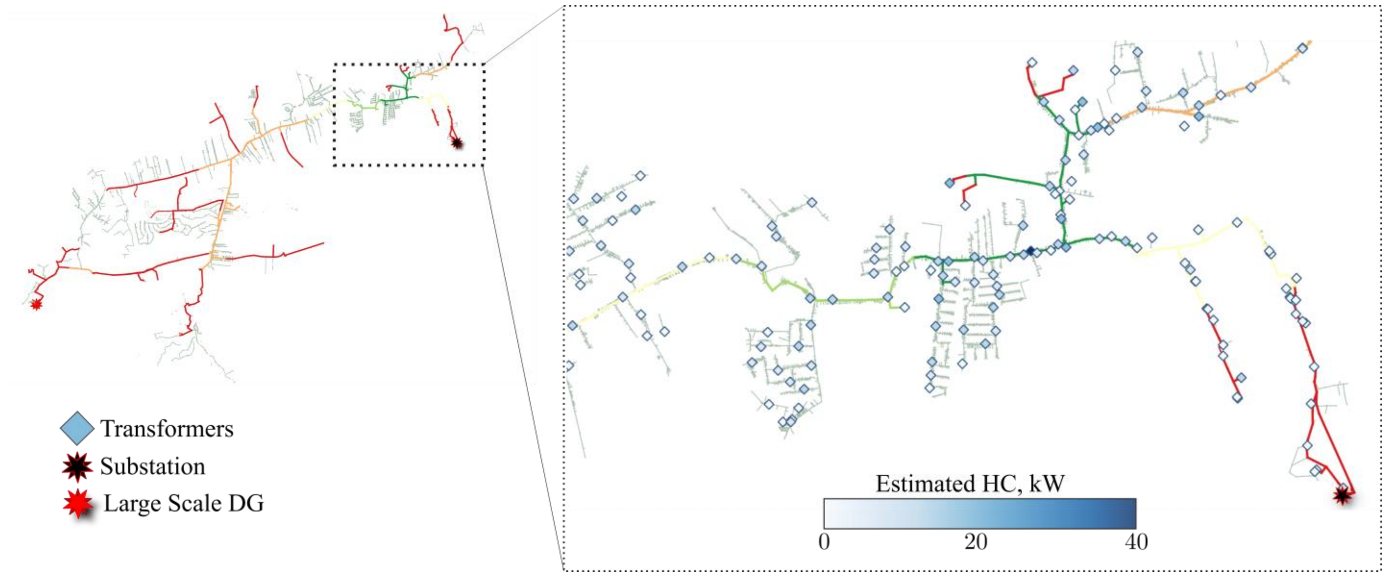

Fig. 10. Locational HC results for feeder 1

Figure 11 presents the evolution of the estimated HC in the iterative process for each feeder. The increase of HC between iterations is the additional DG capacity allocated in the feeder, i.e., $\Delta P_{DG}^{(k)}$, computed in (3) for $\Delta P_{i,max}^{DG} = 5\ kW$. The final HC estimations are marked as stars in Fig. 11.

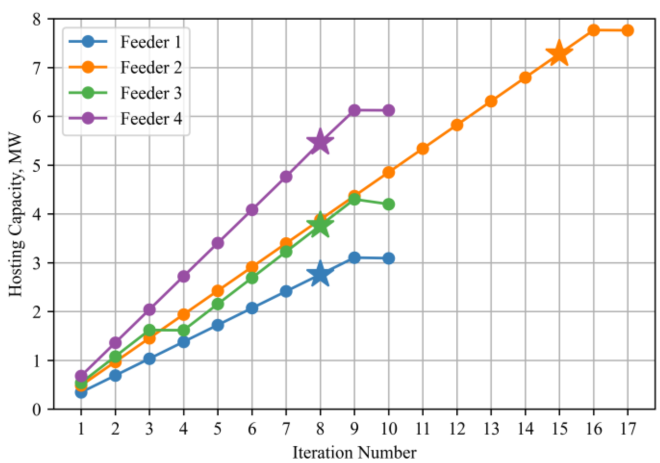

Fig. 11. Evolution of HC per iteration for feeders 1, 2, 3 and 4.

Feeder 1 had an HC of 2.76 MW at the eighth iteration without reported problems for any MV or LV node. For the ninth iteration, the additional DG in the feeder resulted in fifteen secondaries with voltage-deviation problems. Hence, they were reported as not able to host more DGs for the following iterations but kept the DG allocated in the eighth iteration. At the tenth iteration, the redistribution of the percentages in (2) and (7) and the new allocated $\Delta P_{DG}^{(k=10)}$ in the feeder resulted in new voltage-deviation problems in fourteen (previously) reported secondary systems. This stopped the iterative procedure, and the final HC is the last that did not trigger any voltage, thermal or protection problem in the feeder i.e., 2.76 MW. Similar conditions were found for the other feeders.

In feeder 3, two secondary systems resulted in voltage deviations higher than 5% in the third iteration. For the next iterations, these secondaries were reported as unavailable for hosting more DG, and they kept the DG capacity allocated in the second iteration. At the fourth iteration, the redistribution of percentages and the new allocated $\Delta P_{DG}^{(k=4)}$ did not trigger any problem in the feeder. The procedure continued until new secondaries were reported as unavailable to host more DG at the ninth iteration.

For illustration purposes, Fig. 12 presents the HC maps for feeders 2, 3 and 4 with a 1-km resolution. The distribution and location of the existing customers (loads) is also shown for reference purposes. Since the methodology focuses on behind-the-meter DG, the HC maps depend fully on the location of the existing customers. As shown in Fig. 12, feeder sections with fewer secondary systems are reported with lower HC. On the contrary, feeder sections with the highest customer density could host from 0.5 to 0.86 MW aggregate capacities.

The results demonstrated that each feeder could host a DG capacity well above the 15% limit. Feeders 1 and 2 could host 28.8% and 42.3% of their respective peak feeder load, whereas Feeders 3 and 4 could host 37.2% and 40.7%, respectively.

C. *Sensitivity of HC Estimations to Input Parameter* $\Delta P_{i,max}^{DG}$

This section illustrates the impact of varying the input parameter $\Delta P_{i,max}^{DG}$ on the HC estimations for feeder 2. Since the voltage deviation in LV systems was the most limiting factor for all feeders, only the voltage-related evaluation criteria are considered in this analysis.

The sensitivity of HC results to different $\Delta P_{i,max}^{DG}$ values are presented in Table IV. For small $\Delta P_{i,max}^{DG}$ values, the DG increments in the feeder are also small for each iteration, and more DG can be accommodated in the secondary systems before the first voltage violation is encountered. Larger values of $\Delta P_{i,max}^{DG}$ reduces the number of iterations but leads to lower HC estimation results.

Table IV
SENSITIVITY OF HC RESULTS TO DIFFERENT $\Delta P_{i,max}^{DG}$ VALUES IN FEEDER 2.

$\Delta P_{i,max}^{DG}$	HC, MW	Number of iterations	Computing Times, min.
2.5 kW	7.52	32	3.34
5.0 kW	7.28	17	2.2
10 kW	6.80	8	1.3
15 kW	7.28	6	1.1
20 kW	5.83	4	0.89

When all the evaluation criteria are considered, the computational times are considerably higher. Therefore, an input value of $\Delta P_{i,max}^{DG} = 5\ kW$ is a good compromise between time and accuracy.

D. Sensitivity of HC Estimations to Different DG Allocation Assumptions

The proposed allocation of behind-the-meter DG in secondary systems is based on the actual location and demand of the existing customers. However, it is of interest to evaluate other DG-allocation assumptions in the secondary systems.

Table V shows the comparison of HC results between a) the customer-based DG allocation used in this paper, b) all DGs lumped at the beginning of each LV system, i.e., the best-case scenario, and c) all DGs concentrated at the far end of the secondary systems, i.e., the worst-case scenario. The fourth case is explained in Section IV-E.

Table V
SENSITIVITY OF HC ESTIMATIONS IN MW TO DIFFERENT DG ALLOCATIONS IN SECONDARY SYSTEMS.

Feeder	Customer-based HC	Worst-case HC	Best-case HC	GA-based HC
1	2.76	0.69	5.87	3.75
2	7.28	0.97	11.65	7.11
3	3.76	0.54	5.35	4.20
4	5.45	0.68	12.94	8.32

Lumping the DGs at the far end of each secondary results in very low HC estimations. On the contrary, assuming that all DGs will be located at the beginning of each secondary may lead to overestimated HC results. The customer-based DG allocation adopted in this paper, and the corresponding HC results, is more realistic than the other two extreme scenarios.

E. Comparison with HC Maximization Formulation

The HC results from the proposed methodology are compared with those from an optimization problem solved by a Genetic Algorithm (GA). The objective of the optimization is to maximize the amount of behind-the-meter DG in the feeder subject to the voltage constraints defined in Section II-A 1).

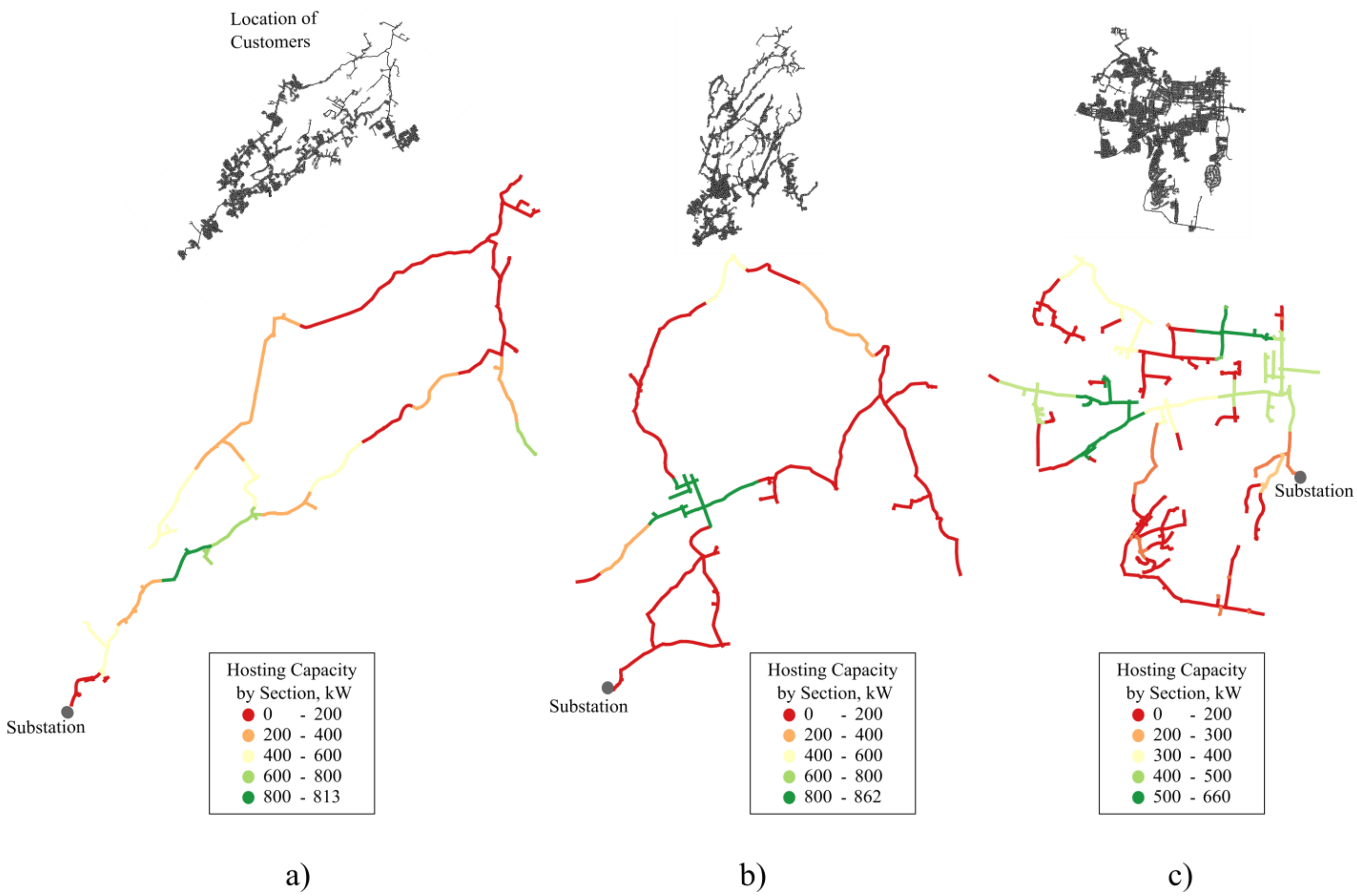

Fig. 12. HC estimation results considering voltage, thermal and protection limiting criteria for feeders a) 2, b) 3 and c) 4.

This approach is similar to the HC maximization introduced in [37]. For this paper, the GA's crossover, mutation, and selection stages were run in *PyGAD* [38].

The following options were selected for each operator: single-point crossover, random mutation (by replacement), and steady-state selection. Moreover, elitism was used to select the best population. The power-flow calculations used to check the constraints of the optimization problem were run in *OpenDSS*, and any violation resulting from the evaluated chromosomes was penalized in the fitness function of the GA. Finally, the number of generations was 100 and the number of solutions (chromosomes) within the population was set to 10.

Figure 13 presents the evolution of the GA's fitness function for each distribution feeder, which translates to the HC results.

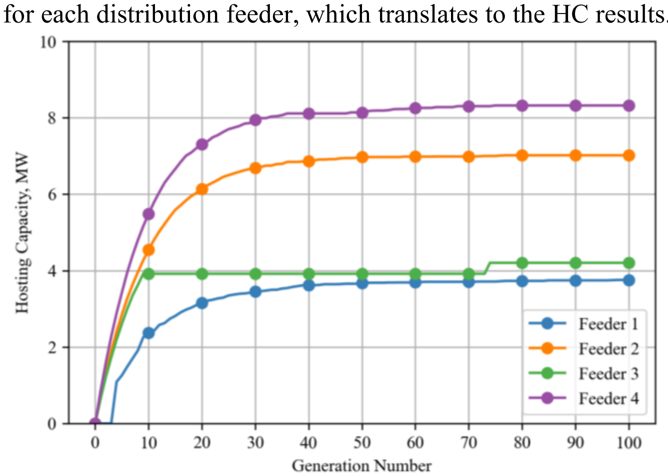

Fig. 13. Evolution of HC results based on the maximization formulation using a genetic algorithm with 100 generations.

The final values from Fig. 13 are listed in the last column of Table V. For feeders 1, 3, and 4, the GA-based results lie between the customer-based and the best-case HC. In feeder 2, the GA-based HC is slightly lower than the customer-based HC estimation.

Since all customers are candidates to host behind-the-meter DG, the search space is very large in all feeders, and this hinders the possibility of the GA finding nearer-optimal solutions. Although using more generations may help to this end, the computational requirements are substantial. For 100 generations only, the GA took 13.2 h, 6.4 h, 33.8 h, and 18. 3 h for feeders 1 to 4, respectively. In contrast, the proposed method with the voltage criteria only took 2.2 minutes for feeder 2, see Table IV for $\Delta P_{i,max}^{DG} = 5\ kW$. Hence, the proposed practical method can provide similar results to those from a GA in much less time.

F. Allocation of DG in Feeder Sections Without Customers

The scope of the paper is to estimate the HC for behind-the-meter DG to be installed by existing customers. Therefore, feeder sections with no customers are reported with low HCs.

A new study is considered in this section to account for the DG installation of future customers. Hence, long feeder sections without existing customers can also host DG. For this, MV nodes that belong to feeder sections without loads become candidates for hosting DG units through distribution transformers with lumped customers in the LV terminals. As the methodology distributes the DG capacity according to the actual demand in the feeder's nodes, see (1) and (2), the future lumped customers are assumed to have a P_i equal to a pth percentile of the active power demand of the existing MV/LV transformers, whereas the rest of the methodology remains the same. In this simulation, the new transformers do not feed any load, they only connect the allocated DGs that grow in the iterative process.

Different connection points able to host DG units from future customers were evaluated. For this, a new transformer is connected in feeder sections that have no load within 400, 300, or 200 meters. This resulted in 9, 25, and 86 new transformers, respectively. Figure 14 shows the location of the existing and new transformers in feeder 2 for the latter case.

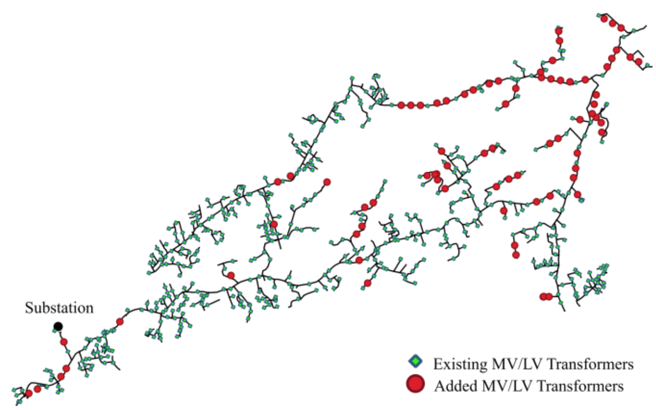

Fig. 14. Location of existing and added MV/LV transformers on feeder 2 for testing the allocation of DG capacity in feeder sections without customers.

Table VI presents the HC results considering the added transformers. The evaluated percentiles define the amount of DG capacity to be distributed to these transformers. The higher the percentile, the more DG capacity is allocated to the new transformers, and the less is allocated to the existing ones.

Table VI
HC RESULTS FOR FEEDER 2 WITH ADDED MV/LV TRANSFORMERS.

HC, MW	Added transformers		
	9	25	86
25th Percentile	7.30	7.34	7.49
50th Percentile	7.38	7.57	8.26
75th Percentile	7.49	7.85	8.63

The inclusion of new points able to host DG increased the HC results with respect to the original estimation of 7.28 MW for feeder 2. Also, the higher the percentile, the larger the HC result. It is important to recall that, unlike the existing transformers, no secondary systems are modeled for the added transformers. Therefore, they are less limited to hosting DG.

V. CONCLUSIONS

This paper presented a new practical method to estimate the hosting capacity of distribution systems for future DG installations of existing customers. The allocation of behind-the-meter generation is based on the location and consumption of the customers in the feeder.

The methodology was tested in four large-scale feeders. In the process, three limiting criteria were evaluated: voltage, thermal and protections. The results show that the HC of feeders was above 15% of their respective peak feeder load. It proves that thumb-based rules could dramatically restrict the inclusion of more DG, closing the door to more sustainable grids.

Voltage deviation is the most frequent reason why secondaries are not capable of installing more behind-the-meter DG. The distance of LV systems from the substation is not necessarily a limiting factor for the capacity these secondary systems could host.

From the sensitivity analysis, it was found that lower input values of $\Delta P_{i,max}^{DG}$ are preferred to obtain more accurate HC estimations. However, using extremely low values of $\Delta P_{i,max}^{DG}$ will increase the number of iterations and computational times.

In terms of the adopted customer-based DG allocation, it was found that it is more realistic than considering a) all DGs lumped at the beginning, or b) the far end of the secondary systems. The former is too optimistic, leading to overestimation results, and the latter is too restrictive. In addition, it was found that HC results from the genetic algorithm lie between those from the customer-based and the best-case HC. However, the proposed methodology provides results in much less time.

The methodology can be easily adapted to consider connection points without existing customers, as presented in Section IV-F, or the connection of future large-scale DGs, and how they will affect the HC in the feeders.

Another advantage of the proposed method is that it is simple to understand and implement and uses information readily available in power utilities. Moreover, power engineers can identify the type and location of violations that prevent more DG allocations. This will be useful for the utility when defining the network reinforcements needed to accommodate more DG capacity. Finally, the proposed methodology provides HC maps with results per MV line section, distribution transformer, and LV system. This is a great advantage for utilities that are required to publish their HC results.

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