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Original Article

Technical Impact of Electric Vehicle Charger Integration in 10 kV Urban Distribution Networks

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Abstract - *The progressive integration of electric vehicles introduces new operational requirements in urban distribution networks, particularly when residential charging occurs under high-simultaneity conditions. This study evaluates the technical impact of integrating single-phase 7.3 kW chargers into a 10 kV urban distribution network, considering a sample of 64 distribution substations and deterministic scenarios ranging from one to four simultaneous chargers per substation. Steady-state power flow simulations were performed, and four technical indicators were analyzed: transformer loading, power factor, phase voltage in p.u., and conductor loading. The results indicate that the number of transformers exceeding 100% load increased from 3.1% to 17.2% when comparing the 7.3 kW and 29.2 kW scenarios. Under the latter scenario, the percentage of transformers with voltage below 0.95 p.u. increased from 12.5% to 25%, while the maximum conductor load increased from 81.2% to 89.9%. Although transformer loading improved, the reduction in thermal and voltage margins could not be offset. Most of the additional load was limited to resistive loads. The study demonstrates important limitations in system operation, which are vital for expanding the load infrastructure, prioritizing network investments, and managing network constraints.*

Keywords - *Home chargers, Power flow, 10 kV distribution network, Electric vehicles, Voltage control, Conductor loading.*

1. Introduction

The shift towards electromobility helps reduce transport-related emissions and develop more sustainable energy systems. The Global Electric Vehicle Outlook 2024 predicts that light Electric Vehicle (EV) sales in 2030 will be in the 30-40% range [1]. This means increased electricity demand on urban distribution networks designed for traditional load profiles. These networks may not be designed to accommodate high-power loads in the residential sector occurring simultaneously.

Charging electric vehicles in residential areas poses challenges for distribution networks. As residential EV loads become more concentrated, the load on distribution transformers can increase, the current on distribution feeders can rise, and voltage profiles can deteriorate. In [2], it is reported that the uncontrolled integration of residential EV chargers can result in overloading of distribution networks and equipment, poor voltage profiles, and the need for mitigation measures. Similarly, in [3], the impact of Level 1, Level 2, and fast chargers can cause voltage dips and poor distribution network performance.

The impact of electric vehicles on low-voltage distribution networks has been the focus of a number of studies. In [4], the simultaneous high demand for traditional vehicles and the charging of plug-in electric vehicles was shown to cause voltage dips and transformer overloading in residential networks. In [5], the impact of varying levels of electric vehicle use in low-voltage distribution networks was also assessed. The results of this study indicated that the technical impact of electric vehicles on low-voltage distribution networks is influenced by the location of the electric load in the network. Because of this, the integration of charging infrastructure needs to consider local operational parameters and not just rely on a global power balance.

From a planning perspective, the integration of a new technology or load into the network needs to consider available network capacity and integration constraints. In [6], the hosting capacity of electric vehicles for low and medium-voltage distribution networks was calculated, incorporating hosting constraints for network operation. In [7], a review of methods to quantify the hosting capacity of electric vehicles and methods to increase this hosting capacity was completed. This review showed the importance of flexible operation, the use of thermal and voltage constraints, and the use of demand management techniques. A considerable portion of existing studies continues to focus on the use of test networks, advanced management techniques, or the use of a probabilistic approach. Deterministic incremental assessments remain needed for the 10 kV urban medium-voltage networks, which contain several distribution substations and are directly verifiable. The gap in the literature that this study seeks to address is the need to understand how the simultaneous and progressive integration of residential Electric Vehicle (EV) chargers changes the operating margins of a 10 kV urban distribution network. Specifically, the focus here is on understanding the order of constraints as they emerge, how they change with increasing connected power, and which parameters are useful for identifying significant technical thresholds in charging infrastructure planning.

This study examines the technical effects of increasing the number of single-phase 7.3 kW residential electric vehicle chargers connected to a 10 kV urban distribution network. The assessment covers 64 distribution substations and four deterministic scenarios defined by the simultaneous operation of one to four chargers per substation. Steady-state power-flow simulations were used to evaluate the network response in terms of transformer loading, power factor, phase voltage in per unit, and conductor loading.

The main contribution of this research is to develop a quantitative, incremental technique for assessing the effects that residential EV chargers have on medium-voltage urban networks. This work aims to specify the operational limitations of transformers, voltage profiles, and feeders. The assessment focuses on identifying network components and operational limitations to assist planners in the prioritization of network reinforcements and demand management. Additionally, the assessment focuses on the prioritization of charging infrastructure by planners. The assessment can be used as a foundation for the deployment of smart and coordinated charging.

2. Methodology

This quantitative method, involving electrical steady-state simulation, was used to evaluate the impacts of integrating residential EV chargers into a Medium-Voltage Distribution (MVD) network [8]. The simulation approach was designed with reproducibility in mind, along with a dedicated infrastructure for defining variables and scenarios, justifying boundary conditions, and establishing clear evaluation metrics. The methodology adopted for the analysis was power flow analysis. Due to the extensive characteristics of the analysis, power flow analysis was preferred for this study [9].

2.1. Electrical System under Study

The 10 kV urban distribution network considered in this study was a medium-voltage distribution network supplied by four (4) primary substations and located in a city with a population of more than 500,000 inhabitants. For this study, a sample of 64 distribution substations was considered (each linked to a distribution transformer and low-voltage residential subscribers).

As is typical of urban distribution networks, the network was represented using a radial scheme. In such a network configuration, growth in demand affects the components of the distribution network, including transformers, voltage profiles, and interconnecting conductors, making the components located at the ends of the network the most affected.

Each transformer was represented in the model by its nominal apparent power and its initial service state. Similarly, the distribution network interconnection conductors were represented in the model by their equivalent electrical parameters of the distribution network, considering the conditions of their operating limits and the power flow analysis.

2.2. Electric Vehicle Charger Integration Model

Residential electric vehicle chargers were modeled as single-phase constant-power loads. This modeling accurately reflects the increased power demand associated with residential charging.

Each charger was assigned a rated power of 7.3 kW, which corresponds to the power level associated with a Level 2 residential charging unit.

The additional power incorporated at each distribution substation was determined as a function of the number of installed chargers operating simultaneously. This relationship is expressed in (1):

$$P_{add} = n_{EV} \cdot P_{EV} \tag{1}$$

In this expression, P_{add} denotes the additional active power at each substation, n_{EV} is the number of simultaneously connected chargers, and P_{EV} is the rated power of one charger. With $P_{EV} = 7.3\text{kW}$ and n_{EV} varying from 1 to 4, the added power per substation was 7.3, 14.6, 21.9, and 29.2 kW.

2.3. Simulation Scenarios

The reference case contained no EV charging load. The analysis then considered four cases with one, two, three, or four chargers connected to each of the 64 distribution substations.

All chargers assigned to a given case operated simultaneously. Table 1 reports the charger count and added power per substation.

Table 1. Electric vehicle charger integration scenarios

Scenario	Simultaneous chargers per substation	Additional power per substation
E1	1	7.3 kW
E2	2	14.6 kW
E3	3	21.9 kW
E4	4	29.2 kW

The total incremental demand for the system in each case was determined by the number of substations under analysis, the number of simultaneous chargers at each substation, and the nominal power of each Level 2 residential charger, as shown in (2):

$$P_T = N_{SE} \cdot n_{EV} \cdot P_{EV} \quad (2)$$

Where P_T is the total additional power incorporated into the system, N_{SE} is the number of distribution substations evaluated, n_{EV} is the number of simultaneous chargers per substation, and P_{EV} is the rated power of each charger. Since 64 distribution substations were analyzed, the total additional power was 467.2 kW, 934.4 kW, 1401.6 kW, and 1868.8 kW for scenarios E1, E2, E3, and E4, respectively.

2.4. Power Flow Analysis

For each EV charging scenario, the steady-state power-flow model calculated nodal voltages, active and reactive power, feeder currents, transformer loading, and conductor loading. The formulation followed the nodal active- and reactive-power balance described in [9]. The active power at each node was obtained from (3):

$$P_i = V_i \sum_{j=1}^{N} V_j \left(G_{ij} \cos\,\theta_{ij} + B_{ij} \sin\,\theta_{ij}\right) \quad (3)$$

Similarly, the reactive power at each node was calculated using (4):

$$Q_i = V_i \sum_{j=1}^{N} V_j \left(G_{ij} \sin\,\theta_{ij} - B_{ij} \cos\,\theta_{ij}\right) \quad (4)$$

In (3) and (4), P_i and Q_i represent the active and reactive power at node i, respectively; V_i y V_j are the voltage magnitudes at nodes i y j; G_{ij} and B_{ij} are the conductance and susceptance associated with the system admittance matrix; θ_{ij} is the voltage angle difference between nodes i y j, and N is the total number of nodes considered in the electrical model. From the power flow solution, the variables required to evaluate the technical impact of charger integration were obtained: phase voltage in p.u., power factor, transformer loading, and conductor loading.

2.5. Technical Evaluation Indicators

The integration of electric vehicle chargers primarily affected transformer loading, power factor, phase voltage in per unit, and conductor loading. These four indicators describe the changing demand's effect on the thermal behavior of the equipment, the quality of the voltage, and the utilization of the components of the network.

Transformer loading was calculated as the percentage ratio between the operating apparent power and the rated apparent power of the transformer. This relationship is expressed in (5):

$$C_{T,i} = \frac{S_{op,i}}{S_{nom,i}} \cdot 100 \quad (5)$$

In (5), $C_{T,i}$ represents the loading of transformer i, $S_{op,i}$ is the operating apparent power of the transformer during each simulation scenario, and $S_{nom,i}$ is the rated apparent power of the same transformer. This indicator determines whether the additional demand associated with electric vehicle chargers moves transformers toward operating conditions close to or above their rated capacity.

Three categories were created for transformer operating ranges when interpreting the results. Available operating margin was defined as when the load was less than 75%. High operating range occurred when the load was between 75% and 100%. Overload was defined as when the load was greater than 100%. This classification was used to determine the number of transformers affected in each electric vehicle load penetration scenario.

The power factor was evaluated to determine the relationship between active power and apparent power in distribution transformers. This indicator was calculated using (6):

$$FP_i = \frac{P_i}{S_i} \quad (6)$$

In (6), FP_i represents the power factor associated with transformer i, P_i is the active power demand, and S_i is the resulting apparent power. This indicator makes it possible to analyze how the incorporation of chargers, mainly characterized by active power demand, modifies the relationship between active and apparent power in transformers.

The obtained values were grouped into three intervals: low power factor when it was below 0.90, medium power factor when it was between 0.90 and 0.95, and high power factor when it exceeded 0.95. This classification allowed the evolution of the phase displacement between voltage and current to be analyzed as the number of simultaneous chargers per substation increased. Phase voltage was evaluated in per-unit values to normalize voltage levels with respect to the system base. This was calculated using (7):

$$V_{pu,i} = \frac{V_i}{V_{base}} \quad (7)$$

Where V_i is the voltage obtained from the power-flow solution and V_{base} is the base voltage. Nodes operating below 0.95 p.u. were classified as low-voltage points. This cutoff corresponds to the lower limit of the ±5% operating band used in distribution studies and to the 0.95-1.05 p.u. reference range established in ANSI/NEMA C84.1 [10].

Finally, conductor loading in the feeders was calculated as the percentage ratio between the operating current and the admissible rated current of the conductor. This indicator is expressed in (8):

$$C_{L,k} = \frac{I_{op,k}}{I_{nom,k}} \cdot 100 \tag{8}$$

In (8), $C_{L,k}$ represents the loading of conductor or section k, $I_{op,k}$ is the operating current obtained in each simulation scenario, and $I_{nom,k}$ is the admissible rated current of the conductor. The calculated percentage indicates the conductor capacity occupied by each charging scenario and the thermal margin that remains available.

For each scenario, conductor loading was summarized by the minimum, maximum, mean, standard deviation, and coefficient of variation. The mean represents feeder-wide utilization. The dispersion measures account for differences among sections. Maximum loading was examined separately because one section may approach its current rating even when the feeder average remains well below that limit.

2.6. Methodological Procedure

Figure 1 organizes the method into system characterization, model construction, scenario simulation, and result evaluation. The sequence links the EV charging cases with the technical indicators defined above. The following subsections describe each stage.

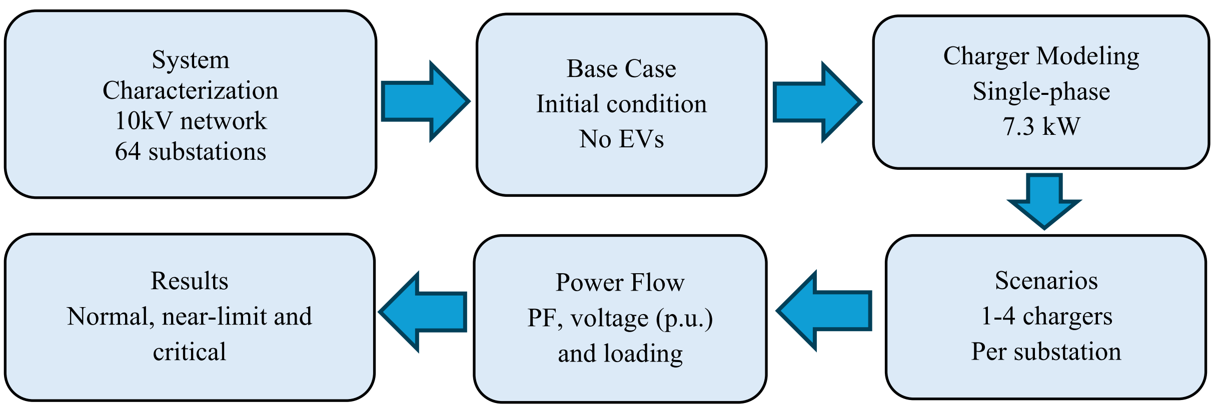

Fig. 1 Methodology for evaluating EV charger impacts on a 10 kV urban distribution network

The method is organized into six sequential steps. The first characterizes the 10 kV distribution network by identifying its distribution substations, transformers, feeders, and baseline operating conditions. After characterization, a baseline case was established. This case represented the state of the distribution network without electric vehicle charging loads. The baseline case was used for comparison with the subsequent scenarios.

The third step of the method involved the modeling of the 7.3 kW single-phase residential chargers as constant power loads and stepwise integration of the chargers at the chosen distribution substations. The fourth step was the development of integration scenarios where one, two, three, and four residential chargers were integrated at the distribution substations. The fifth step of the method was to carry out a power flow analysis in the steady state for each integration scenario and derive the electrical quantities for the defined indicators. The sixth step evaluated transformer loading, power factor, phase voltage, and conductor loading for each scenario.

2.7. Assumptions and Scope of the Analysis

The study at hand utilized a steady-state modeling approach to analyze the cumulative impacts of stepwise installation of residential electric vehicle chargers on transformers, conductors, and medium-voltage urban network voltage profiles. Consequently, the analysis predominantly focused on a number of operational and technical factors, such as transformer loading, network loading in electric power, phase voltage in its per unit (p.u) system, and conductor loading.

As a conservative estimate of demand, the simultaneous operation of the chargers was considered, and this was appropriate for defining critical components and estimating the system's operating margins in extreme situations. Therefore, as explained earlier, this demand estimate is not necessarily the actual user demand at a given hour, but rather allows for the analysis of the system's technical sensitivity in response to a gradual increase in demand for vehicle chargers.

Transient phenomena, harmonics, time-varying loads, and dynamic effects associated with the connection and disconnection of the chargers were disregarded. It should also be noted that, although these are single-phase chargers, the effects of phase imbalance were not considered. These will be addressed in future work using unbalanced three-phase networks and time-series demand patterns.

3. Results

3.1. Transformer Loading

The transformer load distribution for the 64 distribution transformers according to the four electric vehicle charger integration scenarios is shown in Table 2. This classification indicates the number of transformers that are underutilized, operating near their full rated capacity, and overloaded.

Table 2. Transformer loading distribution by connected power

Transformer loading	7.3 kW	14.6 kW	21.9 kW	29.2 kW
Below 75 %	62	54	51	43
75 %-100 %	0	8	5	10
Above 100 %	2	2	8	11
Total	**64**	**64**	**64**	**64**

The results indicate that as load power increases, the available thermal margins for transformers decrease. In the 7.3 kW scenario, 96.9% of transformers were under 75% load. In the 29.2 kW scenario, this percentage decreased to 67.2%. Simultaneously, the percentage of fully loaded transformers increased from 3.1% to 17.2%. As a result, overload conditions are expected with the first level of integration, and these conditions will become more pronounced with subsequent levels of integration.

3.2. Transformer Power Factor

Table 3 presents the power factor distribution of the distribution transformers according to their connected power levels. This parameter was used to assess variations in the relationship between active and apparent power as electric vehicle charging demand was incorporated. The power-factor distribution shifted upward as the charger active power increased. Transformers operating above 0.95 rose from 3.1% in the 7.3 kW scenario to 62.5% in the 29.2 kW scenario. Over the same interval, the proportion between 0.90 and 0.95 fell from 85.9% to 26.6%, while the share below 0.90 remained at 10.9%.

Table 3. Transformer power factor distribution by connected power

Power factor	7.3 kW	14.6 kW	21.9 kW	29.2 kW
Below 0.90	7	7	7	7
0.90-0.95	55	52	34	17
Above 0.95	2	5	23	40
Total	**64**	**64**	**64**	**64**

3.3. Phase Voltage in Transformers

Table 4 groups the 64 transformers according to their per-unit phase voltage. Values below 0.95 p.u. were classified as low-voltage conditions.

Table 4. Phase voltage distribution in transformers by connected power

Phase voltage	7.3 kW	14.6 kW	21.9 kW	29.2 kW
Below 0.95 p.u.	8	9	10	16
0.95-0.99 p.u.	21	21	22	16
Above 0.99 p.u.	35	34	32	32
Total	**64**	**64**	**64**	**64**

Phase voltage decreased as connected charging power increased. The proportion of transformers below 0.95 p.u. rose from 12.5% at 7.3 kW per substation to 25.0% at 29.2 kW. Under four simultaneous chargers per substation, 16 of the 64 transformers operated below the adopted voltage limit.

3.4. Feeder Voltage Profile

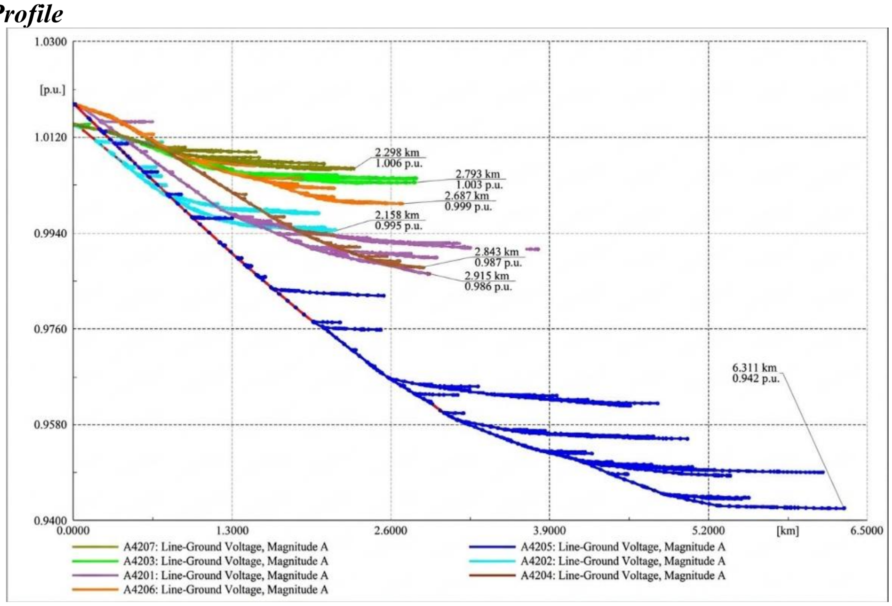

Fig. 2 Feeder voltage profile with one charging station per substation

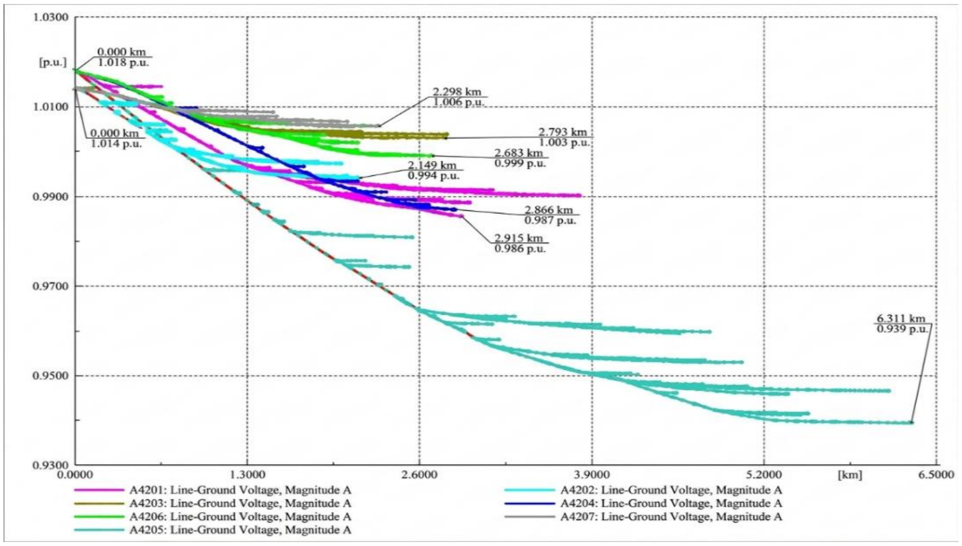

Fig. 3 Feeder voltage profile with two simultaneous charging stations per substation

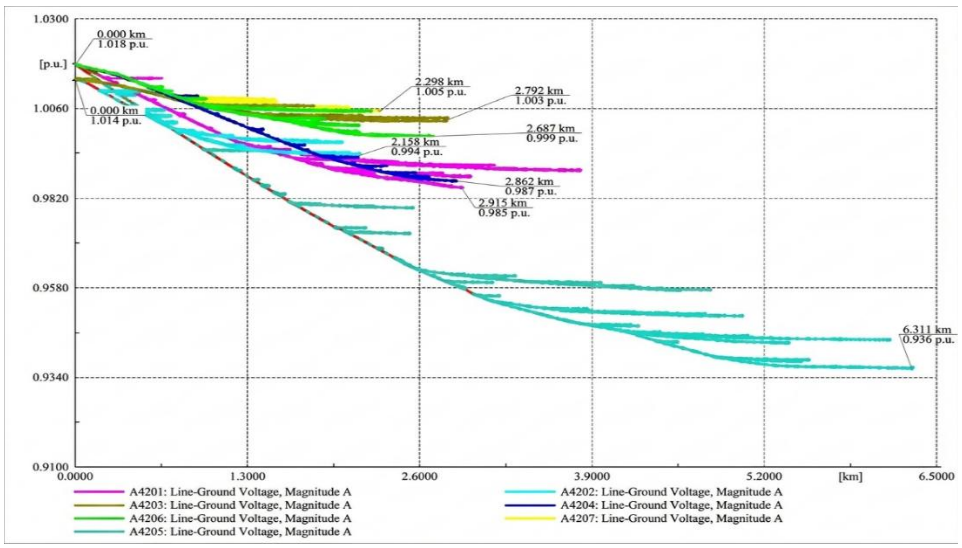

Fig. 4 Feeder voltage profile with three simultaneous charging stations per substation

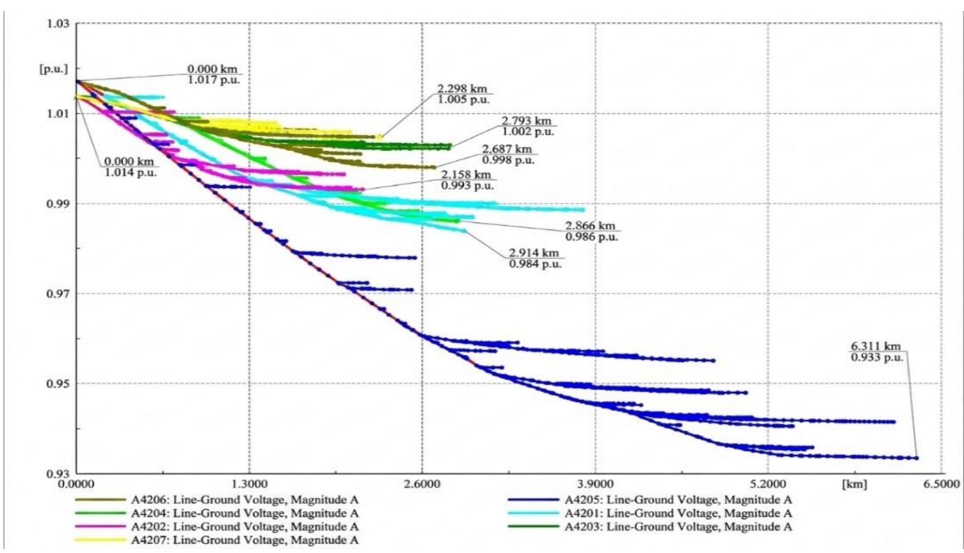

Fig. 5 Feeder voltage profile with four simultaneous charging stations per substation

Figures 2 through 5 plot the feeder voltage profiles for one, two, three, and four simultaneous chargers per substation. Voltage declined along the feeder branches, with larger drops on electrically longer paths.

Table 4 complements these profiles by grouping the transformers according to the 0.95 p.u. threshold.

In the scenarios shown, the voltage drops along the feeders increased with charging demand. In the lower-demand scenarios, most voltage profiles remained within acceptable limits. However, as the number of chargers increased, some branch profiles ended at or below 0.95 p.u.

This behavior is associated with the radial configuration of the system. The most remote nodes exhibited the greatest voltage drop due to the higher cumulative impedance along their feeder paths.

The most affected branches exhibited the largest voltage drops, while other branches remained within similar voltage ranges. The difference indicates that the effect of charging demand depends on the electrical location of the connected load along the feeder.

3.5. Conductor Loading

The conductor loading data for each feeder are presented in Table 5 for each charging-power scenario. Instead of a range-based assessment, the table summarizes feeder behavior using the minimum, maximum, mean, standard deviation, and coefficient of variation.

Conductor loading increased continuously with charging power. Compared with the 7.3 kW scenario, the statistics for the 29.2 kW scenario show that the average conductor loading increased from 53.8% to 56.9%, and the maximum loading increased from 81.2% to 89.9%.

Table 5. Conductor loading statistics by connected power

Indicator	**7.3 kW**	**14.6 kW**	**21.9 kW**	**29.2 kW**
Minimum (%)	30.1	31.1	32.1	33.1
Maximum (%)	81.2	84.0	86.9	89.9
Average (%)	53.8	54.8	55.9	56.9
Standard deviation	17.37	17.89	18.43	19.02
Coefficient of variation	0.32	0.33	0.33	0.33

It is observed that the conductor loading shows a continuous increase with the increase in vehicle charging power. Compared to the 7.3 kW scenario, the statistics for the 29.2 kW scenario show that the average conductor loading increases from 53.8% to 56.9%, and the maximum load value increases from 81.2% to 89.9%.

4. Discussion

4.1. Interpretation of the Main Findings

The results show that the active and simultaneous integration of residential electric vehicle chargers leads to a progressive reduction in the operating margins of the 10 kV urban distribution network. The most significant constraint was found in the load on distribution transformers. In the 7.3 kW modeling scenario, 3.1% of the distribution transformers in a substation were found to be operating above 100% load. This figure increases to 17.2% in the 29.2 kW per substation scenario. This indicates that residential electric vehicle chargers have an uneven impact on the network, and this impact is concentrated on distribution transformers with the lowest thermal capacity.

Voltage regulation also deteriorates as the connected power increases. The proportion of transformers with voltage below 0.95 p.u. increases from 12.5% to 25.0% between the 7.3 kW and 29.2 kW scenarios. This behavior is consistent with the expected operation of radial feeders, where voltage drop increases with current demand and accumulated impedance along the feeder [9]. In addition, the 0.95 p.u. The threshold is consistent with the lower bound of the ±5% operating band commonly used as a reference in distribution systems [10].

Regarding power factor, the results show an apparently favorable trend. The proportion of transformers with a power factor above 0.95 increases from 3.1% to 62.5% as the connected power increases. This behavior can be attributed to the predominantly active nature of the load incorporated by residential chargers. However, this improvement should not be interpreted as an overall improvement in network performance because it occurs simultaneously with an increase in overloaded transformers, a higher number of low-voltage nodes, and a reduction in conductor utilization margins.

With respect to feeders, average conductor loading increases from 53.8% to 56.9%, while maximum conductor loading increases from 81.2% to 89.9%. Although the conductors do not reach a generalized thermal overload condition in the evaluated scenarios, the increase in the maximum value indicates a progressive reduction in operating margin in specific sections. Therefore, maximum conductor loading is more relevant than average loading for identifying local feeder constraints.

4.2. Comparison with Previous Studies

Transformer loading was the first constraint to appear as charging power increased. The proportion of overloaded units rose from 3.1% to 17.2%, whereas no generalized conductor overload occurred. Study [11] reports thermal stress, voltage reduction, and higher losses under residential charging conditions, but the present simulations indicate that these effects depend strongly on the initial loading condition of each network element. Most transformers retained sufficient capacity. Reference [12] linked geographically concentrated, uncoordinated charging with local changes in residential demand peaks. The conductor data show a comparable imbalance. Mean loading changed from 53.8% to 56.9%, while the most heavily loaded section rose from 81.2% to 89.9%. At the highest charging level, that section retained only 10.1% of its rated capacity. A network average of 56.9% did not describe the operating condition at the critical section.

Reference [2] identifies transformer overload, voltage deviation, electrical losses, and power-quality effects among the consequences of unmanaged EV charging. Our simulations reproduced two of those restrictions: transformer overload and low phase voltage. Power factor moved in the opposite direction. More transformers operated above 0.95 as charger power increased, even though overloads and voltages below 0.95 p.u. became more frequent. Power factor alone would have given an incomplete assessment of this feeder.

Studies [6, 7] define hosting capacity through the network restriction reached as EV demand increases. The conductor rating did not set that limit in the analyzed feeder. Transformer capacity became restrictive first, followed by phase voltage. Only the most heavily utilized conductor sections approached their thermal rating [13]. An assessment based only on total connected power would not reproduce this order of constraints. Our simulations fixed simultaneity at one, two, three, and four chargers per substation. No probability distributions were assigned to charger arrival, connection duration, or user behavior, which distinguishes the analysis from the uncertainty treatment reviewed in [14]. The adopted scenarios isolate the response of the network to specific increments of charging power. At 29.2 kW per substation, 11 of the 64 transformers exceeded rated capacity. Those units define the first locations where the mitigation measures discussed in [15] would need to be assessed.

Uniform charging control across the entire feeder would not match the distribution of the observed constraints. Studies [8, 16] propose scheduling and coordinated charging to limit peak demand. In the simulated network, control would be more relevant at the 11 overloaded transformers, at substations operating below 0.95 p.u., and at feeder sections close to 90% utilization. Sections with sufficient residual capacity would not require the same restriction. A location-dependent control scheme could reduce charging simultaneity at the critical points while avoiding unnecessary intervention in the rest of the network.

4.3. Technical Implications for Urban Network Planning

Urban network planning cannot rely only on the total charging power added to the system. The same increase in connected load can produce different effects depending on transformer loading, feeder topology, conductor rating, and charger location. Planning studies should therefore examine each substation and feeder section separately to detect thermal and voltage constraints at the points where they arise. The evaluated network showed three operational risk levels. The first includes transformers that exceeded 100% loading under the minimum charging scenario, indicating that no thermal margin remained. The second includes substations with phase voltage below 0.95 p.u., where the available voltage-regulation margin had already been reduced. The third includes feeder sections that approached 90% of rated capacity under the highest simultaneity scenario, leaving limited capacity for additional charging demand.

4.4. Scope and Limitations of the Study

The study analyzed the steady-state operation of a 10 kV urban distribution system with incorporated residential EV chargers. Thus, the results apply only to the defined modeling conditions. The assumption of simultaneity, which is a conservative approach to a particularly demanding scenario, is helpful for identifying system components that are likely to be strained. It should be noted that, as with other such assumptions, simultaneity captures only a portion of the temporal variability of the user load. The study also omitted the analysis of phase imbalance. This limitation is relevant because the integration of a large number of single-phase chargers can produce current and voltage imbalances in low-voltage distribution networks.

Transient phenomena, load harmonics, residential demand variability, charger dynamics, and connection/disconnection cycles were also excluded from the analysis. Including these factors may affect network losses and the quality of supply. Future research should include unbalanced three-phase models, variable demand profiles, probabilistic simultaneity, and loss assessment to better define the limits of EV integration in urban distribution networks.

5. Conclusion

Adding one to four simultaneous 7.3 kW residential chargers per substation reduced the available operating margin of the 10 kV urban network. The effect did not occur uniformly. Transformer loading became restrictive before conductor capacity, while phase-voltage violations increased as charging power rose. Transformer overload affected 3.1% of the units at 7.3 kW per substation, 12.5% at 21.9 kW, and 17.2% at 29.2 kW. This progression identifies transformer thermal capacity as the first limit for additional simultaneous charging. Voltage conditions followed the same unfavorable trend: the proportion of transformers below 0.95 p.u. increased from 12.5% to 25.0%. Conductors remained below rated capacity in all scenarios, although the maximum loading rose from 81.2% to 89.9%, leaving a limited margin in the most heavily loaded sections. The numerical limits reported here correspond to steady-state conditions and fixed simultaneity levels. A hosting-capacity assessment under daily operation must include unbalanced three-phase models, hourly residential demand and charging profiles, probabilistic coincidence, technical losses, harmonic distortion, and coordinated charging control.

Conflicts of Interest

The authors declare that there is no conflict of interest regarding the publication of this paper.

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