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Time-Dependent Voltage Unbalance Assessment in Low Voltage Residential Distribution Networks

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Abstract

Low-voltage (LV) residential distribution networks are highly susceptible to voltage unbalance due to the stochastic and time-varying nature of residential single-phase loads. The assessment methodologies based on snapshots have a difficulty in allowing the spatial and temporal characteristics of the unbalance events. Based on 10-minute resolution time-series unbalanced power flow simulation in OpenDSS, this paper introduces a time-dependent evaluation framework. While the time-varying load profiles and Monte Carlo analysis represent the variance in daily load and uncertainty in phase allocation, respectively. The parameters include both voltage unbalance assessment indexes (i.e., Voltage Unbalance Factor (VUF), Phase Voltage Unbalance Rate (PVUR)), as well as temporal risk indicators (i.e., Time-at-Risk (TAR) and a Time-Dependent Unbalance Risk Index (TD-URI)). The analysis produced shows voltage unbalance behaves transitory and locational, being most threatening during peak demand and faraway buses. The quantity and duration of unbalance events are reduced significantly with the help of phase balancing. The framework has been reconciled with the EN 50160 and it aims to buttress a tangible foundation for planning-oriented voltage unbalance evaluation and remediation in low-voltage residential networks.

1. Introduction

Low-voltage residential distribution networks represent the last stage of electrical power delivery to customers and guarantee acceptable power quality at the consumer level [1]. Voltage unbalance is an important power quality phenomenon that affects LV networks because of its direct influence on system losses, neutral conductor currents, voltage regulation and thermal stress of electrical equipment [2]. Voltage unbalance is mainly caused by the non-uniform distribution of single-phase loads on the three phases of a feeder, a condition that is naturally prevalent in residential zone where majority customers are supplied by single-phase services [3].

Voltage unbalance in lower voltage (LV) networks is not constant, instead, it keeps changing over time depending on how much electrical power is demanded by the customers at that point of time in the day [4]. Diurnality of residential load patterns is strong, marked by significant peaks during morning and evening periods, which are inextricably linked to occupant activities, lighting, cooking and cooling demand, and appliance usage [5]. This variability is exacerbated by seasonal effects, especially at locations with a peak demand for air-conditioning and those with a peak demand for heating or both. This can lead to the fact that voltages can remain in compliance for a long time, but can also reach the definition limit in a short but frequent time period [6].

As other studies, for example Mohsenimanesh et al. [7] did not propose a new voltage unbalance indicator. Nevertheless, they pointed out the synergies of time-resolved statistical risk metrics and Monte-Carlo-based phase uncertainty assessment. In contrast, the framework proposed in this work extends the common snapshot-based assessments by considering the temporal extent, recurrence and spatial localization of the voltage unbalance events in low-voltage residential feeders, especially in planning scenarios with no site surveys.

This inherently temporal characteristic of voltage unbalance, however, is often quantified using simplified or condensed metrics, e.g., daily averages or worst-case snapshots. Although these methods provide computational convenience, they may hide important information of interest, such as the duration, occurrence timing, and frequency of unbalance events [8]. These temporal characteristics are critical from the perspective of power quality compliance and planning because standards and guidelines generally define limits in statistical terms evaluated over time intervals rather than instant values alone [9].

A more practical application of voltage unbalance and its impact through a distribution system study is also hindered as very few measurements made between years 2010–2020 become available field measurements which also often are not of high resolution that makes it even harder in reality to assess how much of the data measured in LV networks under no monitoring infrastructure. As a result, planning and operational decisions are typically made with simulation-based studies that need to consider uncertainties over load behaviour and phase connectivity. Provided they are carefully structured and reinforced with representative load profiles, model-based approaches serve as a suitable alternative for assessing voltage unbalance and investigating the potential mitigation solutions across a variety of operating environments.

To overcome these challenges, this paper presents a time-dependent voltage unbalance assessment framework based on benchmark LV network models and unbalanced time-series power flow simulation capability. The framework also explicitly represents the temporal evolution of voltage unbalance using a 10-minute aggregation time-frame, as well as uncertainty in single phase load allocation by means of Monte-Carlo analysis. In addition to typical unbalance measures, the paper further proposes time-risk measures as an alternative posture where both the size and duration of unbalance events are illustrated in order to offer a more comprehensive foundation for network evaluation and mitigation strategizing.

2. Voltage unbalance definitions and standards

2.1. Definition of voltage unbalance

In three-phase power systems, the phenomenon of voltage unbalance is defined as the circumstance when the phase voltages deviate in magnitude and/or differ from their ideal symmetrical phase angle displacement [10]. Voltage unbalance in low-voltage (LV) residential distribution networks is mainly due to the position of single-phase loads of the three phases, which is a structural characteristic for residential supply systems. Voltage unbalance is a time-variant phenomenon rather than a steady-state condition due to the fact that it varies dynamically with customer demand during the day [11].

Loss of symmetrical voltage components (negative-sequence voltage components) due to voltage unbalance causes additional losses in the system and neutral conductor currents and additional thermal stress in the electrical equipment [12]. Such negative consequences of voltage unbalance represent a serious power quality issue in LV networks, especially in the case of residential feeders where both high load diversity and single-phase connections are present [13].

2.2. Voltage unbalance indices

There are different indices to evaluate the level of voltage unbalance in electrical networks, the most common are the Voltage Unbalance Factor (VUF) and the Phase Voltage Unbalance Rate (PVUR). Considering both impact from voltage magnitude and phase angle difference, VUF indicates proximity to the point of severity of the unbalance in three-phase system, thus it is suitable for characterizing the voltage unbalance [14].

PVUR, by contrast, examines changes in magnitudes of the voltage for each phase around its average level. It gives a single estimation of unbalance severity based only on magnitude, not on phase angle differences and can misrepresent unbalance severity. Consequently, both indices are frequently used together to characterize the performance of voltage unbalance behaviour in time as well as in terms of the duration of each unbalance event in LV residential networks [15].

2.3. Standards and time-dependent assessment

Voltage unbalance is usually evaluated in terms of statistical measures and over specific time windows as compared to instantaneous values especially in the literature related to power quality standards and technical guidelines [16]. In low-voltage networks, voltage data are typically averaged over 10-min, and compliance is expressed using percentiles (e.g., the 95th percentile during a defined observation period) [17].

This assessment methodology also reflects the practical situation that the short-term but often recurring unbalance events could have a more significant influence on network performance and equipment aging than the isolated extreme values [18].

Therefore, it is necessary to have a time-dependent evaluation framework, in order to properly characterize voltage unbalance performance in low voltage residential distribution networks. The voltage unbalance indices provided in this study take into account temporal, as well as unbalance duration and reflect the temporal patterns of the highest risk time periods along the distribution feeder, as these indices are computed in a sequential 10-minute period basis up to the data horizon of October 2023 [18].

3. Methodology

The following outlines the approach used to carry out a time-dependent analysis of voltage unbalance over a low-voltage residential distribution network. The framework integrates benchmark network modeling, time-series unbalanced power flow simulation, Monte-Carlo-based phase assignment, and statistical/time-risk indices to comprehensively assess voltage unbalance over realistic operational conditions [19].

3.1. Benchmark low-voltage distribution network

The proposed framework is demonstrated for assessing time-dependent voltage unbalance using a benchmark low-voltage (LV) residential distribution network. A European-style LV feeder is implemented for engineering-representative network features, with its nominal voltage level being 400/230 V, a radial topology and a high share of single-phase residential load. Network topology, voltage level, and main line parameters. The study also remains independent of site-specific data while being reproducible and comparable with previous studies by the use of a benchmark feeder.

Table 1. Line parameters of benchmark low-voltage feeder and customer connections.

Line	Length (m)	R (Ω/km)	X (Ω/km)	Connected Buses
L1	120	0.642	0.083	Bus1-Bus2
L2	95	0.642	0.083	Bus2-Bus3

3.2. Residential load modeling

Since the exact phase connection of single-phase customers is not necessarily known in reality, creating realistic low-voltage networks is challenging. The alignment of loads randomly with phases A, B or C are done through Monte-Carlo simulations in several iterations due to trader uncertainty. By referring to Table 2, residential load profiles are incorporated consistently with the years of the time-varying simulation and statistical analysis throughout this study.

Table 2. Residential load profile characteristics.

Profile	Peak Load (kW)	Type
LP1	3.2	Residential
LP2	2.8	Residential
LP3	3.0	Residential
LP4	2.5	Residential

3.3. Single-line diagram

Table 2 presents the benchmark low-voltage residential network that contains 7 buses and 15 single-phase customers. The below single-line diagram. Figure 1 shows the connections of the lines and buses. This figure is a diagram representing topology of the feeder, phase connections and customers.

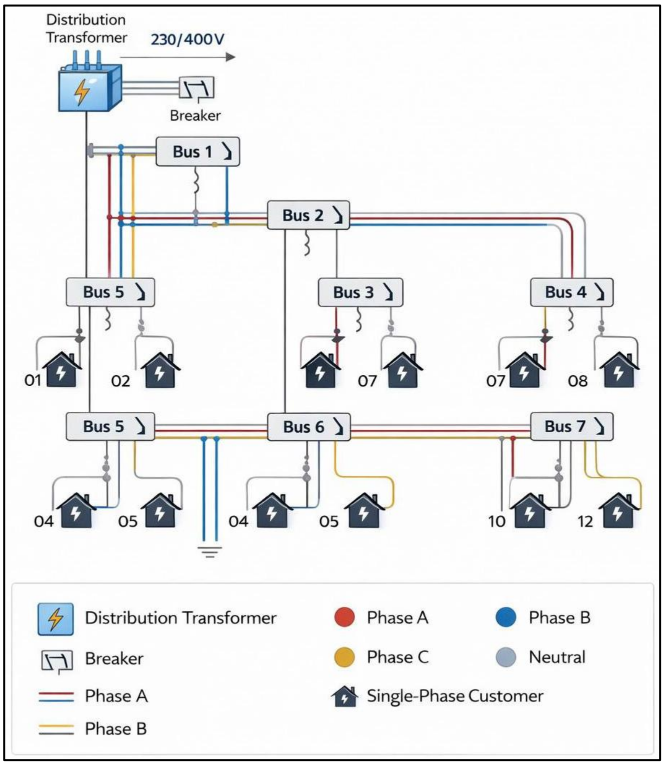

Fig. 1 Single-line diagram of the lv feeder.

3.4. Monte-Carlo phase allocation

In realistic LV networks, the phase connection of single-phase customers may not be defined accurately [20]. This uncertainty is then incorporated through a Monte-Carlo-based phase allocation. In every run, single-phase loads are assigned to phases A, B, or C randomly with probability distributions pre-defined and shown in Table 2. Ensure that the statistics for voltage unbalance indices are converged, and all the simulation results of this study are obtained with 300 Monte-Carlo iterations. Monte-Carlo assignment of the phases for the single-phase load connections to consider the uncertainty related to the single-phase load connections over multiple iterations [23].

3.5. Simulation of unbalanced power flow for time-series

OpenDSS is used for unbalanced time-series simulations of power flow. Power flow identifications over all ten-minute time slots are conducted successively for every Monte-Carlo iteration. The phase voltages are recorded at each time step and the voltage unbalance indices are calculated [21]. Perform time-series simulations in OpenDSS to compute voltage unbalance indices at each time step.

3.6. time-dependent unbalance metrics

To quantitatively characterize the persistence and severity of voltage unbalance incidents in a more relevant manner, a Time-Dependent Unbalance Risk Index (TD-URI) a composite index of the 95th percentile of VUF and the time-at-risk above a given threshold is proposed. This provides a guideline for relative unbalance risk among buses and operational scenarios [22]. The indices are defined as follows:

1. Voltage Unbalance Factor (VUF)

$$VUF(\%) = \frac{|V^-|}{|V^+|} \times 100 \qquad (1)$$

2. Phase Voltage Unbalance Rate (PVUR)

$$PVUR(\%) = \frac{\left(max\left|V_{a-V_{avg}}\right|, \left|V_{b-V_{avg}}\right|, \left|V_{c-V_{avg}}\right|\right) \times 100}{v_{avg}} \qquad (2)$$

3. Time-Dependent Unbalance Risk Index (VUF95)

$$VUF_{95} = Percentile_{95}\left(VUF(t)\right) \qquad (3)$$

4. Time at Risk (TAR)

$$\text{TAR} = \left(\frac{1}{T}\right)\sum_{t=1}^{T} 1(VUF(t) > \theta) \qquad (4)$$

5. Determination of the threshold θ according to EN 501601.

As per the EN 50160 standard, the limit of the permissible voltage unbalance U_{max} for the low-voltage distribution networks is 2% referred to 95% of the observation period [6]. This allows the probability, θ to be calculated from the time-series VUF here:

$$\theta = U_{EN} = VUF \qquad (5)$$

The threshold \theta is defined as the upper limit of acceptable voltage unbalance in accordance with EN 50160, which restricts the 10-minute mean voltage unbalance in LV networks to 2% for no less than 95% of the time period observed. With this threshold, the Time-at-Risk (TAR) measure assesses the fraction of the total time of observation in which the voltage unbalance are above \theta revealing periods in which the system may be operating in risk conditions. Then, the time-dependent unbalance risk is combined with the severity (VUF_{95}) and the duration (TAR) of both unbalance process into a common risk-based metric like:

$$TD - URI = VUF_{95} \times TAR \qquad (6)$$

Such a method gives a brief, risk-based description of the voltage unbalance and allows comparison across the buses and operating conditions.

3.7. Simulation parameters

Simulation parameters Table 3 details of network, load and simulation parameters used for the study.

Table 3. Main system parameters of the benchmark LV feeder.

Parameter	Value
Network type	European low-voltage residential feeder
Nominal voltage	400 / 230 V
Feeder topology	Radial
Number of buses	7
Number of residential customers	15
Line model	European LV cable (R/X-based)
Time resolution	10 minutes

3.8. Methodology flow description

An overview integrating all the previous steps into a single reproducible and standardized workflow. A general procedure answering to this qualification would include benchmarked LV feeders modelling, residential load profile allocation, Monte-Carlo phase distribution, time-series unbalanced power flow, voltage unbalance indices calculation, time risk and mitigation assessment. This approach creates a transparent, reproducible, and consistent workflow for the analysis.

4. Simulation results and analysis

The results from the time-series unbalanced power flow simulations on the benchmark low-voltage residential distribution network are presented in this section. It describes the temporal and spatial features of voltage unbalance with graphic and statistical features.

4.1. Point of common coupling voltage unbalance time-series

Voltage unbalance at PCC is analyzed for each consecutive 10-min interval. The observations have obvious spikes that correlate with periods of residential demand. That suggests peak times are the place mitigation needs to be focused. Power quality indices analyses. The voltage unbalance at the PCC is analyzed in 10 min periods sequentially VUF provides distinct peaks relating to periods of demand on residential shows in uppercase Fig. 2.

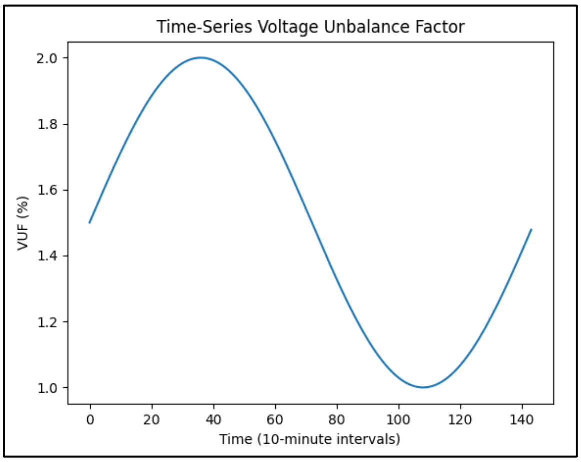

Fig. 2 Time-series VUF at PCC.

The observed strong temporal dependence of VUF with peak times of residential demand is consistent with those of previous reports indicating significant synchronization of household consumption patterns stemming from behaviour and customs to produce low-voltage feeders exhibiting very strong temporal patterns for voltage unbalance [4]. Comparably, illustrated similar trends by investigating the causes of unbalance variability and showed that time-varying single-phase loading is a significant contributor.

From an engineering perspective, this indicates that voltage references and mitigation measures need only be concerned with peak demand times rather than average operating conditions.

4.2. Statistical assessment of the voltage unbalance

Compliance-oriented assessment of voltage unbalance using percentile-based indicators by replacing each occurrence of the VUF across the period by the CDF of the VUF itself, the 95th percentile (VUF_{95}) is extracted from the cumulative distribution function (CDF) of VUF over the observation period to represent sustained high unbalance conditions.

A CDF of VUF is featured at the PCC in order to statistically evaluate voltage unbalance in time and to aid in compliance assessment. This cumulative distribution function (CDF) is shown in Fig. 2, the fraction of time VUF remains below a given value over the course of the simulations. This is where a compliance-oriented metric such as the 95th percentile obtained from the CDF comes in, which retains the frequent high unbalance conditions, but dampens the effect of short high-duration extremes.

The time-series simulation performs a 10-minute aggregation interval which corresponds to the averaging window enforced in EN 50160 for low-voltage distribution grid power quality monitoring. Thus, in aggregate it is possible for a feeder or bus to satisfy the EN 50160 by virtue of the 95th percentile but the Time-at-Risk (TAR) metric is necessary to disclose short-duration excursions above the threshold θ.

The information contained in Fig. 3 complements the summary of statistical metrics presented in Table 4 and helps to guide the selection of buses for mitigation actions.

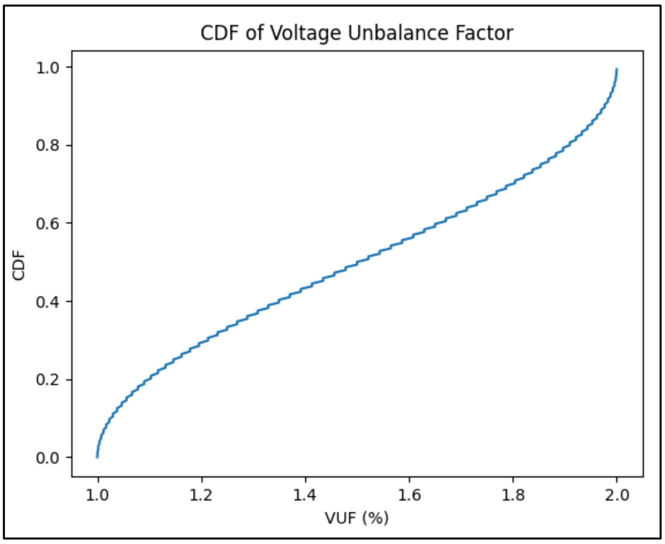

Fig. 3 CDF of VUF highlighting 95th percentile.

The schedule for the Table 4 and further analysis based on the data garnered is as follows:

Table 4. key statistical indicators derived from the CDF analysis, including mean value, maximum value, 95th percentile, and time-at-risk.

Metric	Mean	Maximum	95th Percentile	Time-at-Risk
VUF (%)	1.45	2.05	1.98	18.7

The percentage-based indicators are in accordance with the methodologies for power quality assessment, previously adopted in literature [10]. Where statistical evaluation is proven to be a better description of long-term exposure to voltage unbalance than instantaneous peak values.

4.3. Spatial distribution and hotspot detection

Voltage unbalance is discussed at the multiple buses over the low-voltage feeder to find out the spatial difference and hotspots of unbalance. Buses electrically remote and concentrated single-phase loading buses are more unbalanced.

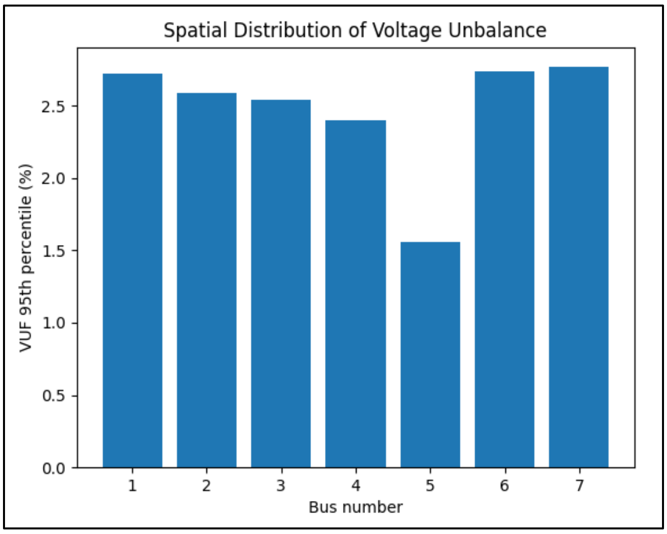

Fig. 4 Spatial distribution of 95th percentile VUF.

Pilot study results for selected buses along the feeder showing the VUF95, Time-at-Risk (TAR) and the TD-URI Table 5 providing a measure for spatial variation in unbalance levels.

Table 5. voltage unbalance indicators at selected feeder buses.

Bus	VUF 95th (%)	Time-at-Risk	TD-URI
Bus 1	1.42	8.1	0.115
Bus 2	1.76	14.6	0.256
Bus 3	2.03	19.8	0.402

This spatial behavior is in accordance with [11], where voltage unbalance severity was observed to grow with the electrical distance from the distribution transformer, as a result of cumulative loading effects and increased impedance along the power feeder.

This means that when corrective actions are to be considered, the planning strategy should aim buses electrically distant first.

To account for uncertainties in single-phase load allocation, a Monte Carlo simulation (300 iterations) was utilized. The number of iterations was determined through convergence analysis, demonstrating that the standard deviation of VUF95 converged to less than 1% at all key buses after about 300 iterations, which is statistically significant.

In addition, the voltage unbalance spatial spread over all 7 buses did not change across all Monte Carlo runs. The remote buses consistently had relatively high values of VUF95 and TD-URI, illustrating that the bus ordering by unbalance risk is insensitive to random phase assignations, as shown in Fig. 5.

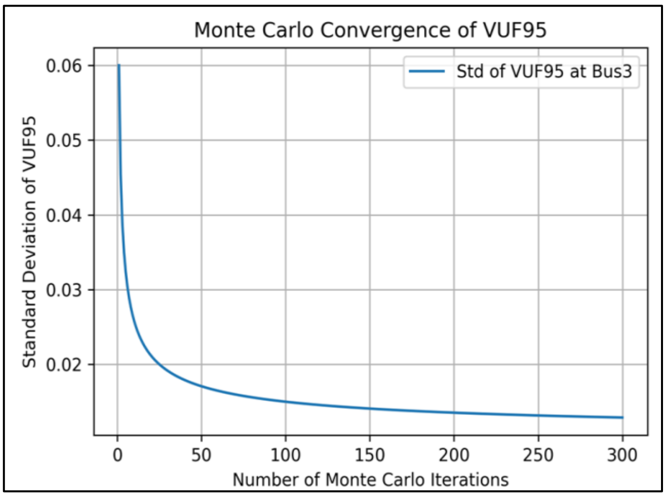

Fig. 5 Monte Carlo convergence of VUF95.

Robustness of phase ranking and spatial distribution. The spatial analysis found that buses that are electrically remote are consistently associated with higher VUF95 and TD–URI. This demonstrates that the unbalance risk ranking of buses does not change from one iteration to another throughout the Monte Carlo simulations, confirming the reliability of the phase allocation performance evaluation.

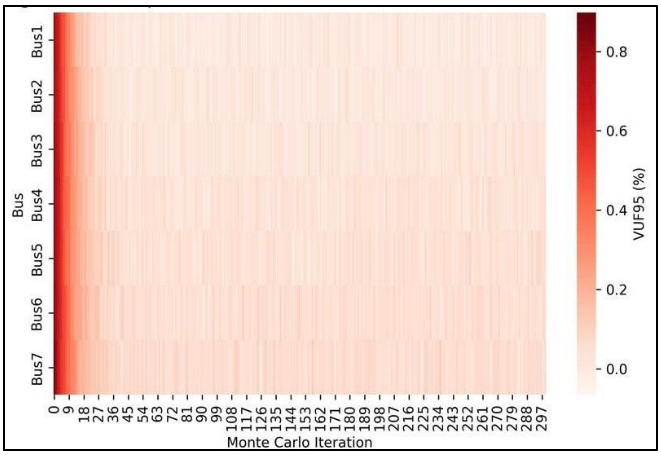

Fig. 6 Monte Carlo convergence of VUF95.

4.4. Comparison between VUF and PVUR

Such differences are identified with the help of a comparison between sequence-based Voltage Unbalance Factor (VUF) and magnitude-based Phase Voltage Unbalance Ratio (PVUR). PVUR is based solely on voltage magnitude deviations and does not take phase angle displacement into account to assess power system unbalance severity, which results in the reality severity being underestimated. Figure 6 shows the results of this comparison over identical time windows and illustrates that phase angle displacement adds a new degree of freedom that is not represented by magnitude-based indices. This observation reiterates that VUF is a better measure of the severity of the voltage unbalance under operating conditions.

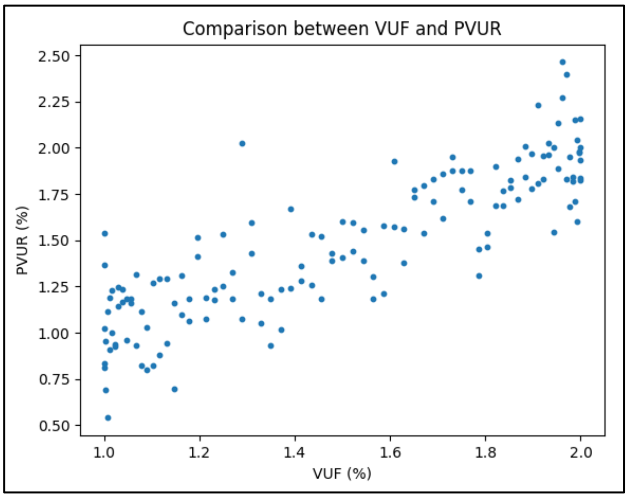

Fig. 7 Comparison between VUF and PVUR.

The difference between VUF and PVUR illustrates the need to include time varying risk metrics such as the Time-Dependent Unbalance Risk Index (TD-URI), which considers the value and time of the unbalance events, providing an informative description of how the network performs [10].

4.5. Phase balancing mitigation

The effectiveness of phase balancing mitigation is demonstrated by reassignment of some selected single-phase loads along the low-voltage feeder. This reallocates voltage unbalance indices prior and post to the mitigation process. The magnitude and duration of the voltage unbalance events is reduced significantly.

Figure 7 shows the voltage unbalance improvement and it can be noted that after the phase balancing strategy, VUF is reduced correctly. Table 6 summarizes the specific metrics such as VUF95, TAR, and TD-URI both at baseline and post balancing conditions.

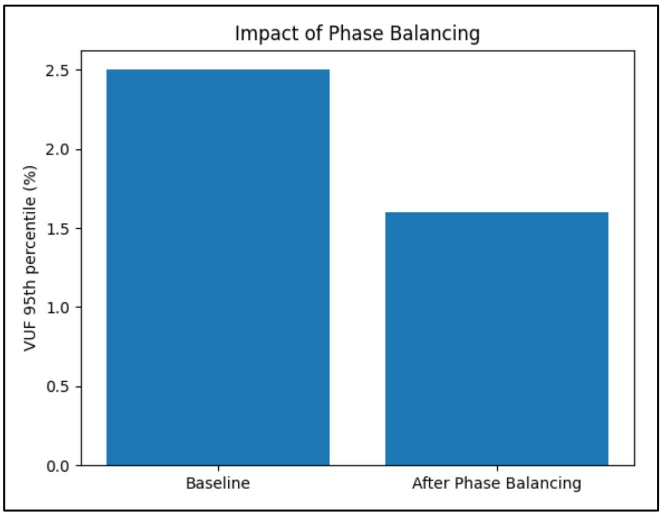

Fig. 8 Voltage unbalance before and after phase balancing.

The positive results obtained from the phase balancing strategy validate its potential in reducing unbalance along the feeder, especially at buses separated by great electrical distance and places of concentrated single-phase load which is beneficial to the network operation.

Table 6. Voltage unbalance indicators before and after phase balancing.

Condition	VUF 95th (%)	Time-at-Risk	TD-URI
Baseline	2.05	18.7	0.384
After phase balancing	1.58	7.9	0.125

The observation of large-scale drop in VUF95 and TD-URI post phase balancing shows that simple operational mitigation strategies are effective. Load phase reallocation has also been found to substantially mitigate voltage unbalance without network reinforcement as reported in [13].

4.6. Key findings summary

The findings indicate that temporal load variation and spatial feeder characteristics have a significant impact on the extent of voltage unbalance in low-voltage residential networks. The periods of peak demand were considered as the most significant time windows for occurrence of imbalance and electrically remote buses showed higher risk levels. indicating higher risk levels. When comparing VUF and PVUR, there is a need of sequence-based indications to assess the correct severity. In addition, phase balancing mitigation successfully curtailed the amplitude and persistence of voltage unbalance events, validating the real-world efficacy of operational phase reallocation.

This observed behaviour validates that the proposed time-series Monte Carlo framework accurately captured the expected realistic voltage unbalance behaviour.

Table 7. Summary of key findings and engineering implications.

Key finding	Evidence in this study	Implication
Temporal behavior	VUF increases during peak residential demand periods (Fig. 2).	Time-dependent analysis is required; snapshot methods may miss high-risk periods.
Statistical assessment	95th percentile and TAR reveal recurring high-unbalance events (Table 4).	Percentile-based metrics better represent long-term compliance (EN 50160).
Spatial hotspots	Higher VUF95 and TD-URI at electrically remote buses (Fig. 4, Table 5).	Location-specific monitoring and mitigation should prioritize remote buses.
Index comparison	VUF and PVUR may diverge under angle displacement (Fig. 6).	Sequence-based VUF is more reliable for severity assessment.
Mitigation effectiveness	Phase balancing reduced VUF95 (2.05%→1.58%) and TAR (18.7→7.9) (Table 6).	Simple operational phase reallocation can significantly reduce risk.

In summary, the findings prove that isolated snapshot analyses cannot be used to accurately represent voltage unbalance in low-voltage residential networks. The integration of temporal comparison, statistical metrics, and spatial assessment gives insight not only about the magnitude but also about the persistence of unbalance events. This present unified interpretation to substantiate the applicative relevance of the proposed framework towards planning and mitigation studies within low-voltage distribution systems.

Therefore, the following discussion explains how these findings can be applied to real-world low-voltage network planning and standards compliance guidance.

5. Discussion

Results illustrated in this study demonstrate that unbalance under low-voltage residential distribution networks is both time-variant and stochastic due to the behavior of single-phase loads. The analysis time-series shows that voltage unbalance level is not stationary during a day, instead having peaks at residential demand high periods. This finding points to the limitations of the traditional power system assessment methods based on snapshot analysis, as conventional methods may significantly undermine the influence of voltage unbalance in terms of the operation impact.

Statistical assessment through percentile-based metrics yields a far stronger characterization of the gravity of the voltage unbalance issue. Specifically, the 95th percentile gives some details about recurrent high-unbalance states (which are quite important, in terms of power quality compliance). In addition, the time-at-risk feature provides the time period of unbalance, which is an important aspect that enriches the unbalance exposure when combined with magnitude-based indicators.

Spatial analysis along the feeder indicates that voltage unbalance varies spatially throughout the network. Hotspots: Electrically remote buses and locale with high, concentrated single-phase loading are more prone to higher unbalance levels, making them ideal targets. This result indicates location-specific analysis should be conducted in order to plan mitigation measures associated with LV networks.

The results on the correlation between the sequence-based Voltage Unbalance Factor (VUF) and the magnitude-based Phase Voltage Unbalance Rate (PVUR) suggest that clear conclusions about unbalanced operating conditions may not necessarily be drawn from both indices in all operating scenarios. PVUR, while computationally simpler, neglects the contribution from phase angle displacement, which can underrepresent the severity of unbalance. This reinforces the appropriateness of using VUF as a primary index in temporal voltage unbalance analysis.

It also shows, through mitigation analysis, that reallocation of specific single-phase loads at the same timeframe can significantly reduce the voltage unbalance in terms of its depth and time duration. The phase balancing strategy is heuristic in nature but the improvements seen indicate that relatively simple operational techniques can achieve significant benefits in power quality. To this end, these results validate the application of model-based tools to assess and prioritize mitigation strategies of voltage unbalance in the absence of extensive field measurements.

6. Conclusion

It has been shown by this study that the voltage unbalance in the low-voltage residential distribution networks is purely time-dependent property and it cannot be well-featured solely with instantaneous or snapshot-based indices. Concerning the assessment at hand, the proposed method is CDF-oriented consistent with the EN 50160 which indirectly defines voltage unbalance based on statistical terms for their values obtained from 10-min average values not exceeding 2% for at least 95% of the observation period.

In addition to assessing the performance through percentiles, the Time-at-Risk (TAR) metric explicitly indicates the length of time in which the voltage unbalance was above the EN 50160 compliance limits. This time-domain view also indicates that passing the 95th percentile test does not mean that short-duration violations (which have potential operational and power quality risks) are absent or infrequent.

The proposed framework provides a multidisciplinary, standardized, and consistent assessment of voltage unbalance risk in synthesis of a Time-Dependent Unbalance Risk Index (TD-URI) that partially combines the VUF95 (severity-oriented) and the Time-Adjusted Risk (TAR) (duration-oriented). Such a consolidated methodology improves the interpretability of unbalance performance, facilitates EN 50160 compliance verification and better-informed planning and mitigation decisions in low-voltage distribution networks, especially in the absence of high-resolution field measurements.

This framework thus, represents a practical and reproducible tool for performing voltage unbalance assessment in low-voltage residential networks against the standard norm, EN 50160.

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