Event-informed Allocation of Energy Storage, Voltage Regulators and Infrastructure Upgrades in Distribution Network Planning

Juan J Cuenca, Marta Vanin, Md Umar Hashmi, Arpan Koirala, Hakan Ergun, Barry Hayes

Event-informed Allocation of Energy Storage, Voltage Regulators and Infrastructure Upgrades in Distribution Network Planning

Juan Cuenca [1], Marta Vanin [2], Md Umar Hashmi [2], Arpan Koirala [2], Hakan Ergun [2], and Barry Hayes [2]

[1]University College Cork
[2]Affiliation not available

October 31, 2023

Abstract

This article presents a novel numerical approach aimed at finding a distribution network expansion plan that prevents future congestion and voltage issues. Forecasted duration and intensity of thermal and voltage violation events are used to determine a pool of potential candidates for infrastructure (i.e., line/cable) upgrade, voltage regulator, and energy storage system installations. This is complemented with an algorithm to obtain the minimum-cost list of these candidates that solves all constraint violation events using binary linear programming. This approach is validated using the modified IEEE 33-bus network and a real 1171-bus feeder in the West of Ireland through numerous high-resolution quasi-static time series simulations. Three pools of candidates and three cost projections were considered to explore the method's sensitivity to different scenarios. Results show that the proposed methodology is a versatile tool for designers, planners and policymakers. The methodology can ensure that the investment plan solves all forecasted violation events. Nevertheless, we show that accepting a marginal degree of violations may be acceptable and would significantly reduce investment costs.

Event-informed Allocation of Energy Storage, Voltage Regulators and Infrastructure Upgrades in Distribution Network Planning

Juan J. Cuenca, *Member, IEEE,* Marta Vanin, *Member, IEEE,* Md. Umar Hashmi, *Member, IEEE,* Arpan Koirala, *Member, IEEE,* Hakan Ergun, *Senior Member, IEEE,* Barry P. Hayes, *Senior Member, IEEE*

***Abstract*—This article presents a novel numerical approach aimed at finding a distribution network expansion plan that prevents future congestion and voltage issues. Forecasted duration and intensity of thermal and voltage violation events are used to determine a pool of potential candidates for infrastructure (i.e., line/cable) upgrade, voltage regulator, and energy storage system installations. This is complemented with an algorithm to obtain the minimum-cost list of these candidates that solves all constraint violation events using binary linear programming. This approach is validated using the modified IEEE 33-bus network and a real 1171-bus feeder in the West of Ireland through numerous high-resolution quasi-static time series simulations. Three pools of candidates and three cost projections were considered to explore the method's sensitivity to different scenarios. Results show that the proposed methodology is a versatile tool for designers, planners and policymakers. The methodology can ensure that the investment plan solves all forecasted violation events. Nevertheless, we show that accepting a marginal degree of violations may be admissible and would significantly reduce investment costs.**

***Index Terms*—Battery energy systems, distribution network expansion planning, flexibility, power distribution lines, power distribution planning.**

I. Introduction

THERE is growing attention from industry and the research community around the evolution of electricity distribution networks. Expected industrial and residential growth, inclusion of new loads resulting from the electrification of heat and transport systems, and inclusion of distributed energy resources (DER) [1], [2] represent a challenge for the planning of future grids. Distribution network planning is shifting away from a traditionally passive approach (i.e., waiting for issues to manifest, and reacting with infrastructure upgrades (IU) and voltage regulators (VR) to solve them) [3]. Different forms of flexibility like energy storage systems (ESS) are proposed as non-wire alternatives (NWA) to address these challenges.

In this context, this manuscript takes the perspective of the system operator planning its grids to prevent future congestion and voltage issues resulting from increasing load and generation connections. Traditionally, system operators carry out demand projection studies that help them design grid expansion plans consisting of IUs (i.e., conductor resizing, adding parallel branches, etc.) and VRs [4], [5]. This way, the grid capacity increases, as well as the potential to connect additional load and generation resources. Alternatively, grid-scale flexibility resources (e.g., ESS) can act as flexible loads or generators that allow the grid to cope with excess demand or supply in certain operational moments - reducing the probability of constraint violation events [6].

The calculation, quantification and definition of the set of investments that prepare the grid for the future are also known as distribution network expansion planning (DNEP) [7]. This process is challenging, because distribution networks have less resource aggregation and present more variability than their transmission equivalent (i.e., distribution networks have fewer aggregated customers, which makes demand and generation states harder to predict compared to the transmission level). Furthermore, distribution networks have many more direct customer connections than the transmission system. Thus, the applicability of transmission network-inspired optimisation algorithms to the DNEP problem is hampered by algorithmic considerations, such as computational intensity [8].

Existing approaches for the DNEP problem in the literature involve the definition of one or multiple objective functions (e.g., minimising investments, emissions, etc.), a set of constraints (e.g., network constraints, reliability, etc.), a temporal model (e.g., dynamic, static, or pseudo-dynamic), a network model, and a solution algorithm (e.g., mathematical, evolutionary, hybrid, artificial intelligent, etc.) [7]. While these approaches can consider stochastic or deterministic parameters, integer or continuous variables, they always result in a non-convex problem that is hard to solve exactly in reasonable time [8]. These require relaxations and scenario reduction approaches that can potentially misrepresent the complexity of distribution network applications.

This paper proposes a novel approach that can overcome such computational drawbacks, relying on forecasts of future congestion and voltage issues. The information on the constraint violation events is leveraged to design a binary linear programming (BLP) problem which accounts for the remote influence that the different candidate installations present on such events.Using this tool, grid operators, policymakers and designers can extract a list of investment candidates that together address future technical issues of a distribution network at the minimum cost. Furthermore, this method allows

This work has been funded by the Department of Business, Enterprise and Innovation, under the Government of Ireland's Project 2040 Plan ("CENTS" project, contract DT 2018 0040-D).

the evaluation of multiple pools of candidates in a short computational time, making it a practical tool to complement other planning methods. Ultimately, to understand the potential trade-offs between the proposed approach and the common industry practices, they are compared from a technical and economic point of view through extensive simulation work. The main contributions of this work are as follows.

1) Presenting a novel methodology for the location and sizing of IU, VR and ESS candidates applicable to radial distribution networks. This is based on the duration and intensity of forecasted constraint violation events and the physics of electricity networks.
2) Offering an accessible/practical BLP tool for system operators, policy-makers and designers to decide among these potential candidates from a technical point of view, and to translate them into a minimum-cost investment plan (i.e., a DNEP). This is validated through extensive simulation work.

A comparison with selected articles from the literature showing the benefits of the proposed method in terms of computational intensity is ultimately followed by a discussion on the opportunities, challenges, scalability, and applicability of the proposed approach.

The paper is structured as follows: Section II presents the state of the art and limitations of the current practices and research on the DNEP problem. This is followed by Section III where the event-informed numerical method is formulated. A working example is presented with results in Section IV and Section V presents details of the simulation-based validation process. Conclusions, recommendations and future work opportunities are discussed in Section VI.

II. State of the Art

This section presents the resources available in the literature and currently used by system operators to address congestion and voltage issues in distribution networks. A selection of recent works dedicated to solving the DNEP is also presented.

A. The traditional approach

1) Infrastructure upgrades: the most common tool used in distribution network planning for congestion issues is the reinforcement of problematic lines (i.e., changing the existing conductor size or including an additional parallel branch). This is an immediate solution for congestion issues as the current-carrying capacity of the new installation is designed to withstand the forecasted congestion. Additionally, voltage issues are marginally mitigated thanks to the reduction in the voltage drop due to lower resistances associated with the larger cross-section conductor/parallel branch. However, upgrading the infrastructure can be costly depending on the situation: it may require changes in the mechanical infrastructure (e.g., poles and mechanical supports) [9] or the refurbishing of underground infrastructure [10].

Obtaining planning permission to make changes in distribution networks is becoming increasingly difficult, especially in urban settings. Right of way limited access, lack of community acceptance and externalities result in long waiting times for permitting and approvals. This presents a barrier that is currently delaying necessary IUs in already-congested distribution networks [11], [12].

2) Installing voltage regulators: voltage issues are commonly addressed by installing VR (e.g., on-load tap-changing (OLTC) regulators) in critical parts of the distribution network. These can ramp up or down the voltage as a response to a reference going over/under a predefined value [13]. Observability is a limitation of VR which can adjust voltage based on a local voltage measurement performed on the load side of the instrument. These underperform when DER production exceeds local demand because the voltage is increased if local energy is exported. The work in [2] shows that in some cases VRs can exacerbate over-voltage in portions of a network due to high DER production at the end of a feeder being mistaken for a voltage drop at the head of the feeder.

3) Changing the feeder voltage rating: when a combination of IU and VR is not considered a viable solution, the alternative is increasing the voltage rating on all portions of the distribution feeder. An increased voltage rating simultaneously reduces the current through the lines and addresses voltage issues. However, it is much more costly and carries significant technical and planning challenges (e.g., change in mechanical structures, isolation ratings, rating of medium/low voltage (MV/LV) transformers, adapting protection systems, etc). Moreover, this is only possible for MV networks because the voltage level in LV networks is already bound by the standard. Feeder voltage rating change will not be considered in this study.

B. Flexibility as an alternative

Alternative approaches to tackle future issues are referred to as NWAs. The premise is that controllable resources can curb peak load and generation to alleviate constrained networks [14]. This, in turn, serves as a means to defer otherwise necessary IU and VR installations and can represent an important economic benefit [15]. While IU and VR can be costly [16], they are still the current industry standard registered in grid codes globally [17], [18]. As discussed before, some of the IU candidates may be unfeasible due to non-technical restrictions (e.g., lack of community acceptance), which highlights the relevance of including NWAs as expansion candidates.

1) Demand-side management: demand-side management is offered by users that have the capability to defer their energy usage. However, asking users to reduce their consumption in peak-usage moments may be an unreliable solution as discussed in [19], because the commitment to do so is not firm. This means that in practical terms, demand flexibility is less relevant for system operators because of its unreliability, and is therefore not considered in this study. Nonetheless, the work in [20] presents a decision-support tool including demand flexibility for DNEP.

2) Energy storage systems: energy storage owned by the system operator can provide flexibility to alleviate congestion and reduce the incidence of voltage drop/increases. It can store excess energy at critical points of the grid when there are problematic flows and release it when the grid is not under

stress. This purpose for ESS is referred to as load levelling, peak shaving and load shifting [21].

C. Solutions for the DNEP

As discussed before, existing approaches for DNEP address the problem using numerous definitions of objective functions, constraints, temporal and network models, parameters, solution algorithms, as well as relaxations and scenario reduction approaches. This results in a large number of research articles on this topic [7].

Notable methods for DNEP are presented in [22], [23], where authors model grid constraints using a modified augmented relaxed optimal power flow approach that convexifies the classical AC optimal power flow. Another approach by the authors in [6] is to use a pre-processing tool for scenario reduction due to the high computational cost of considering a larger range of operational states. A common way to solve the problem is also through a linearised DC power flow [24]. The work in [25] proposes an enhanced mixed-integer linear programming (MILP) model for multistage DNEP considering reliability-related costs. [26] proposes an approach for DNEP that involves relaxing the $N-1$ design criterion to alleviate the computational burden of the problem. Authors in [27] include reliability assessment as a constraint to cast the DNEP as an instance of MILP for mesh-designed but radially-operated distribution networks. [28] characterises uncertain demand and generation through polyhedral uncertainty sets, and convexifies the AC power flow (ACPF) to solve the optimisation problem.

A review of DNEP articles is presented in [7]. Since these rely on some form of relaxation or approximation, they offer either a non-global optimal solution, or a mathematical solution to an overly simplified problem [29]). Similar arguments are presented in [30], where the performances of classical and meta-heuristic models for reconfiguration of distribution systems are compared.

D. Gaps and limitations

On the one hand, current DNEP approaches in the literature present important challenges in terms of computational intensity (with run times of hours to days, that grow exponentially with the size of the network [22–28]). System operators may prove reluctant to apply these methods because of the large number of networks to study, their size, and the amount of operational scenarios to analyse. Furthermore, methods that require relaxation and scenario reduction approaches, may not be workable for the DNEP problem, because of the increased uncertainty from lower levels of aggregation. On the other hand, the work in [29] argues that existing transmission-inspired MILP optimisation methods lack guaranteed optimality, or result in optimality within an overly simplified search space, making them less rigorous (i.e., providing mathematical, but not engineering solutions). The method proposed can complement existing ones as part of a pool of decision-support tools for system operators.

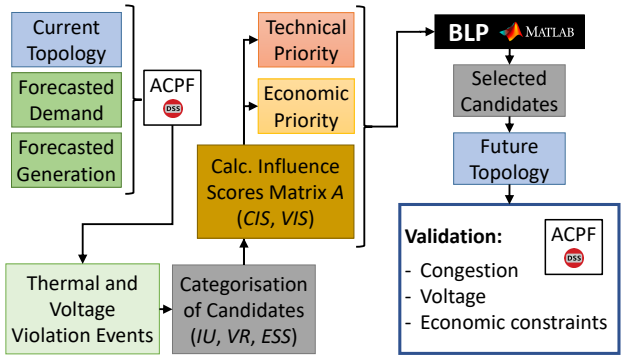

Fig. 1: Overview of the proposed methodology. Using the topology and forecasted demand and generation of a target year, it is possible to find candidates that solve all congestion and voltage issues at the minimum cost.

III. Proposed Method

This section presents the proposed numerical approach. The outcome of a study of this nature is a DNEP combining IU, VR, and ESS (and their characteristics). This allows the future operation of the grid without congestion and voltage issues derived from forecasted demand and generation. Fig. 1 presents an overview of the steps to define and prioritise candidates, to select the minimum-cost plan, and to validate if the future topology solves forecasted events.

A. Preliminary identification of constraint violation events

Forecasted consumption and generation patterns in distribution networks can show which portions of the grid require reinforcement through IU or VR, or can benefit from grid-scale ESS. The first step requires identifying and prioritising the constraint violation events: this gives an idea of the relative urgency of certain upgrades/installations over others, as well as clues on their location and size. If consumption and generation patterns are appropriately forecasted for future scenarios, it is possible through simulation work to determine which portions of the network may present congestion and voltage issues.

An ACPF simulation is proposed to determine voltage profiles and power flows for the studied network. Values resulting from the ACPF can be normalised as a percentage of a limit being breached: for the case of voltage, the tolerable voltage drop/increase given by the local regulation authority (often ±2%, ±5% or ±10% voltage deviations for MV networks [31]). Similarly, power flows are normalised as a percentage of the line loading rating of the existing line to represent thermal limits. Given a grid with a set of lines L and a set of nodes N connected, voltage deviation $\Delta V_{n,t}$ in node n can be expressed as a percentage $\Delta V^{\%}_{n,t}$ of the predefined limit ΔV^{LIM}_{n} for each time step t of the examined time window $\mathcal{T}$, using (1). Similarly, power flow $S_{l,t}$ for all time steps t in each line l can be expressed as a percentage $S^{\%}_{l,t}$ of the thermal rating of the conductor S^{LIM}_{l} using (2).

$$\Delta V^{\%}_{n,t} = (\Delta V_{n,t}/\Delta V^{LIM}_{n}) \times 100 \; ; \forall \; t \in \mathcal{T}, \; n \in N \qquad (1)$$

$$S^{\%}_{l,t} = (S_{l,t}/S^{LIM}_{l}) \times 100 \; ; \; \forall \; t \in \mathcal{T}, \; l \in L \qquad (2)$$

It is important to differentiate violation events in terms of origin. A radial distribution network congested due to excess demand means that power flows are going towards the customer side, creating under-voltage issues at the end of the feeder. If the congestion occurs due to excess generation, power flows are going towards the head of the feeder, creating over-voltage issues. Thus, a candidate's (i.e., IU, VR or ESS) influence on these events will depend on its origin: ESS for example reduces congestion towards the head of the feeder when charged with excess generation from the end of the feeder. Any congestion or voltage issue is assumed to be different if they respond to an excess in demand or generation. In line with this, it is useful to define congestion as demand-caused $S_{l,t}^{dem}$ or generation-caused $S_{l,t}^{gen}$.

The intensity and duration of all violation events (i.e., $\Delta V_i^{\%}$ or $S_l^{\%}$ are higher than 100%) can be calculated. It is proposed that any potential IU, VR or ESS, or combination of these, must address all the events either locally or remotely. While there is an entire range of potential constraints at the distribution level (e.g., unbalance, harmonics, fault constraints, etc.), this work focuses on voltage and thermal limits to define "constraint violation events".

The preliminary calculations from the ACPF can be time-consuming if a large enough amount of forecasted demand-generation scenarios is considered. However, the literature offers different approaches to reduce this computational time [32], [33]. Moreover, this preliminary simulation must be run only once to assess violation events: once candidates are sized based on this initial simulation, the decision-making process (represented by the BLP solution) requires a very small computational cost relative to other methods in the literature for the DNEP problem as shown below.

B. Numerical approach

It is possible to use the duration and intensity of events to size, locate and prioritise candidate solutions. This is done by calculating each candidate's local and remote influence for voltage and congestion. The proposed method complements existing decision support tools used by modern system operators, including transmission-like methods, other DNEP approaches, network reconfiguration studies, etc. Moreover, it is a practical mechanism that incorporates traditional design practices, and ultimately represents a straightforward implementation that is expected to be of great interest for industry. Its formulation is presented below.

1) Locating and sizing candidates: defining which combination of IUs - exclusively - solves the congestion issues is a trivial calculation. The new current-carrying capacity (i.e., new limit) $S_{l,new}^{LIM}$ of a line l part of the subset of problematic lines Lp should be above the maximum violation identified previously, this can be calculated using (3).

$$S_{l,new}^{LIM} = \max_{\forall t \in \mathcal{T}} \{S_{l,t}^{\%}\} * S_l^{LIM};\ \forall\ l \in L_p \tag{3}$$

This can be complemented by locating VRs in one or more nodes, part of the subset N_q with voltage violation events. VRs can alleviate voltage events up to the range of the regulation equipment (typically ±10% of the nominal voltage) on the subset of nodes N^{ν} part of its area of influence. These regulators must have increased observability (i.e., the possibility to sense voltage drop/increase in the primary and secondary as discussed in [34]). Together, these IU and VR represent the candidates for the traditional expansion plan calculated by system operators, responding to forecasted issues.

Alternatively, local congestion issues can be solved by installing an ESS in nodes next to congested lines. The capacity and charge/discharge rating of the ESS is proposed to be determined using the intensity and duration of the associated congestion events. Consider a node n connected to one or more congested lines (the latter represented by the subset L_n). The maximum charge/discharge rating $CH_{n,ESS}^{rate}$ necessary to solve local congestions of the subset of lines can be calculated as the maximum difference between new conductor ratings and original conductor ratings using (4).

$$CH_{n,ESS}^{rate} = \max_{\forall l \in L_n} \{S_{l,new}^{LIM} - S_l^{LIM}\} \tag{4}$$

To calculate ESS capacity it is important first to define the nodal loading that comes from excess demand $S_{n,t}^{dem}$ or generation $S_{n,t}^{gen}$ in a given time step t, as the maximum power flow that occurs in any congested line l connected to n. The nodal limit coming from connected lines S_n^{LIM} is represented by the minimum thermal limit in any of them.

$$S_{n,t}^{dem} = \max_{\forall t \in \mathcal{T}} \{S_{l,t}^{dem}\};\ \forall\ l \in L_n \tag{5}$$

$$S_{n,t}^{gen} = \max_{\forall t \in \mathcal{T}} \{S_{l,t}^{gen}\};\ \forall\ l \in L_n \tag{6}$$

$$S_n^{LIM} = \min\{S_l^{LIM}\};\ \forall\ l \in L_n \tag{7}$$

The capacity of the ESS $E_{n,ESS}$ is then calculated by finding the maximum energy that would be required to solve all congestion events in any day, either from demand or generation excess. This is given by the maximum between daily-aggregated demand-caused and generation-caused congestion issues using (8). This approach accounts for two or more subsequent congestion events without enough time for the ESS to charge/discharge back into levels that could address the second congestion. This will be tested with a daily cycle, where any charge or discharge occurs on a day.

$$E_{n,ESS} = 2 \times \max \left\{ \begin{array}{c} \sum\limits_{t \in day} [(S_{n,t}^{gen} - S_n^{LIM}) \times t] \\ \sum\limits_{t \in day} [(S_{n,t}^{dem} - S_n^{LIM}) \times t] \end{array} \right\} \tag{8}$$

2) Addressing local violation events: it is possible to define and calculate the local congestion and voltage influence scores (CIS and VIS respectively) of every candidate (i.e., the ability of the candidate to solve the local voltage and congestion violation event). For IUs, VRs and ESS, these are given respectively by (9), (10) and (11)[1].

$$CIS_{IU_l,l}^{local} = 1; \forall\ l \in L_p \tag{9}$$

[1]Naming convention as follows: $CIS_{X_{a,b}}^{local}$ reads "*local congestion influence score that installing X in element a has on element b*".

$$VIS^{local}_{VR_n,n} = \frac{\Delta V^{VR}_{range}}{\max\limits_{\forall t \in \mathcal{T}}\{\Delta V_{n,t}\} - \Delta V^{LIM}_{n}}; \forall\ n \in N_q \quad (10)$$

$$CIS^{local}_{ESS_n,l} = 1\ , \forall\ l \in L_n \quad (11)$$

3) Addressing remote events: Some candidates can solve congestion and voltage issues in remote locations. Previous work [16] used coincidence factors (i.e., correlations between intensity and occurrence of events) as an indication of the potential of a local solution to have a remote effect. This paper proposes an alternative based on the physical relationships between technologies, congestion and voltage drop, analogue to the critical sensitivity indices in [35].

Voltage drop δV over a line is calculated using (12), where I is the transported current, Λ is the length of the conductor with a cross-section A_{cond}. The influence of temperature, the material (e.g., copper or aluminium) and the configuration of the installation (e.g., three-phase or single-phase) is represented by the constant k. Voltage drops can be added for different sections that have various values of current, length and cross-sections. For this study, Λ is assumed constant because lines are only upgraded, not rerouted.

$$\delta V = \frac{k \times I \times \Lambda}{A_{cond}} \quad (12)$$

The candidates dimensioned above can have direct and/or indirect influences over congestion and voltage drop/rise: IU and ESS have a direct influence on congestion, and an indirect influence on voltage via the increased conductor cross-section and reduced line loading, respectively. VR have a direct influence on remote voltages and a negligible influence on congestion. The following relations are defined when it comes to remote addressing of congestion and voltage issues:

- IUs only affect congestion locally, therefore its remote influence on congestion $CIS^{remote}_{IU_l,l_b}$ in a remote line l_b is assumed to be zero.

$$CIS^{remote}_{IU_l,l_b} = 0\ ; \forall\ l_b \in L \quad (13)$$

A remote influence on voltage will be considered from IUs for each node n part of the subset N^* that has voltage issues and is part of the direct path of the current that goes through the upgrade. The remote voltage influence score $VIS^{remote}_{IU_l,n}$ of upgrading line l in voltage-problematic node n is calculated using the proportion between the change in voltage drop across the line l (i.e., from the old line and the line after the IU), and the maximum voltage event seen by n.

$$VIS^{remote}_{IU_l,n} = \frac{\left(\frac{\delta V^{old}_{l} - \delta V^{new}_{l}}{\delta V^{old}_{l}}\right)}{\max\limits_{\forall t \in \mathcal{T}}\{\Delta V_{n,t}\}} \quad (14)$$

Voltage drops across non-upgraded sections also remain unchanged. Assuming that k remains constant, with some intermediate steps (12) can be used to rewrite (14) as:

$$VIS^{remote}_{IU_l,n} = \frac{1 - (A^{old}_{l}/A^{new}_{l})}{\Delta V^{MAX}_{n}} \quad (15)$$

- VRs have zero influence in remote congestion (16). In contrast, a VR installed in node n with bandwidth $\Delta V^{range}_{n,VR}$ alleviates voltages in nodes $n_b \in N^{\nu}$ that see the regulator as head of the feeder (17):

$$CIS^{remote}_{VR_n,l_b} = 0\ ; \forall\ l_b \in L \quad (16)$$

$$VIS^{remote}_{VR_n,n_b} = \frac{\Delta V^{range}_{n,VR}}{\max\limits_{\forall t \in \mathcal{T}}\{\Delta V_{n_b,t}\} - \Delta V^{LIM}_{n_b}} \quad (17)$$

- A remote influence on congestion will be considered from ESS installations for the subset of lines L^{ν} that are part of the direct path of the current that goes through the element. This influence depends on the origin of the congestion. As discussed before, demand-caused and generation-caused congestions are treated differently.

Assuming that the ESS responds to a congestion signal, any charge with magnitude $CH^{rate}_{n,ESS}$ in congested moments is the power that is not going to flow through the grid and as such alleviates congestion in remote sections. We assume that the ESS does not cause problems when charging/discharging back in moments without constraint violation events.

$$CIS^{remote}_{ESS_n,l} = \frac{CH^{rate}_{n,ESS}}{\max\limits_{\forall t \in \mathcal{T}}\{S_{l,t}\} - S^{LIM}_{l}}\ ; \forall\ l \in L^{\nu} \quad (18)$$

Since voltage drop is directly proportional to the current flowing through a conductor, an ESS reducing congestion, also has a positive impact on voltage issues across the network. A similar approach to that of the voltage influence score for IUs can be used. The difference here is that instead of the current being constant, the cross-section remains constant. Therefore, using (12) and (14) for a constant k, we find the remote voltage influence score as follows,

$$VIS^{remote}_{ESS_n,n_b} = \frac{1 - (I^{new}_{l_a}/I^{old}_{l_a})}{\max\limits_{\forall t \in \mathcal{T}}\{\Delta V_{n_b,t}\}} \quad (19)$$

where $I^{old}_{l_a}$ is the maximum current in any congestion event and $I^{new}_{l_a}$ is the reduced current in a congestion event when the ESS alleviates congestion in line l_a, the line connected to the node n where the candidate ESS is proposed - looking towards n_b. While reducing the current flowing through the lines between n and n_b reduces voltage drop in all of them, it is proposed to calculate only the voltage influence score for the node n_b - this simplifies the problem and makes it a conservative approach: the candidate is assigned a smaller influence than it has in reality. Ultimately, using the same base voltage to work with power flows instead of currents, (19) can be rewritten as follows.

$$VIS^{remote}_{ESS_n,n_b} = \frac{CH^{rate}_{n,ESS}}{\max\limits_{\forall t \in \mathcal{T}}\{S_{l_a,t}\} \times \max\limits_{\forall t \in \mathcal{T}}\{\Delta V_{n_b,t}\}} \quad (20)$$

$$\mathbf{A} = \begin{array}{c} \begin{matrix} l_1 & l_2 & \dots & l_p & n_1 & n_2 & \dots & n_q \end{matrix} \\ \begin{bmatrix} 1 & 0 & \dots & 0 & VIS^{rem}_{IU_1,n_1} & VIS^{rem}_{IU_1,n_2} & \dots & VIS^{rem}_{IU_1,n_q} \\ 0 & 1 & \dots & 0 & VIS^{rem}_{IU_2,n_1} & VIS^{rem}_{IU_2,n_2} & \dots & VIS^{rem}_{IU_2,n_q} \\ \vdots & \vdots & \ddots & \vdots & \vdots & \vdots & \ddots & \vdots \\ 0 & 0 & \dots & 1 & VIS^{rem}_{IU_p,n_1} & VIS^{rem}_{IU_p,n_2} & \dots & VIS^{rem}_{IU_p,n_p} \\ 0 & 0 & \dots & 0 & VIS^{loc}_{VR_1,n_1} & VIS^{rem}_{VR_1,n_2} & \dots & VIS^{rem}_{VR_1,n_q} \\ 0 & 0 & \dots & 0 & VIS^{rem}_{VR_2,n_1} & VIS^{loc}_{VR_2,n_2} & \dots & VIS^{rem}_{VR_2,n_q} \\ \vdots & \vdots & \ddots & \vdots & \vdots & \vdots & \ddots & \vdots \\ 0 & 0 & \dots & 0 & VIS^{rem}_{VR_q,n_1} & VIS^{rem}_{VR_q,n_2} & \dots & VIS^{loc}_{VR_q,n_q} \\ 1 & CIS^{rem}_{ESS_1,l_2} & \dots & CIS^{rem}_{ESS_1,l_p} & VIS^{loc}_{ESS_1,n_1} & VIS^{rem}_{ESS_1,n_2} & \dots & VIS^{rem}_{ESS_1,n_q} \\ CIS^{rem}_{ESS_2,l_1} & 1 & \dots & CIS^{rem}_{ESS_2,l_p} & VIS^{rem}_{ESS_2,n_1} & VIS^{loc}_{ESS_2,n_2} & \dots & VIS^{rem}_{ESS_2,n_q} \\ \vdots & \vdots & \ddots & \vdots & \vdots & \vdots & \ddots & \vdots \\ CIS^{rem}_{ESS_r,l_1} & CIS^{rem}_{ESS_r,l_2} & \dots & 1 & VIS^{rem}_{ESS_r,n_1} & VIS^{rem}_{ESS_r,n_2} & \dots & VIS^{loc}_{ESS_r,n_q} \end{bmatrix} \end{array} \begin{array}{l} IU_1 \\ IU_2 \\ \vdots \\ IU_p \\ VR_1 \\ VR_2 \\ \vdots \\ VR_q \\ ESS_1 \\ ESS_2 \\ \vdots \\ ESS_r \end{array} \tag{21}$$

4) Prioritisation of candidates: considering local and remote benefits, candidates can be ranked from a technical perspective. By adding influence scores, the designer or system operator can determine which candidate performs best as a standalone installation. The maximum hypothetical score that a candidate can obtain is equal to the number of problematic elements, this would mean that such candidate is able to solve all the issues on its own.

Moreover, the candidates can be ranked from an economic perspective. As the technical specifications of each candidate are known, their costs can be calculated. The global score defined by the designer or grid operator divided by the cost of the candidate represents its technical benefits per cost unit.

5) Finding the minimum cost investment: since it is not expected that one candidate is able to solve all issues, the last step is defining which combination of candidates does it at a minimum cost. First, the local and remote influence scores on congestion and voltage issues can be registered in a matrix of influence scores $\mathbf{A}$ as in (21). Each candidate has an associated score between 0 and 1 in all the p congested lines and q voltage-problematic nodes, therefore $\mathbf{A}$ has a size of $[p+q] \times [p+q+r]$ (i.e., number of problematic elements $\times$ number of candidates).

The binary vector $\mathbf{x}$ containing the decision variables x_i to install or not each candidate i out of all options (i.e., p IUs, q VRs, and r ESS candidates) is defined in (22). This vector has size $p+q+r$. Similarly, the costs c_i associated with each candidate i are contained in the vector $\mathbf{c}$ (23).

$$\mathbf{x} = [x_{IU_1}, ..., x_{IU_p}, x_{VR_1}, ..., x_{VR_q}, x_{ESS_1}, ..., x_{ESS_r}] \\ x_i \in \{1, 0\};\ \forall\ i \tag{22}$$

$$\mathbf{c} = [c_{IU_1}, ..., c_{IU_p}, c_{VR_1}, ..., c_{VR_q}, c_{ESS_1}, ..., c_{ESS_r}] \tag{23}$$

Finding the minimum-cost list of candidates that solve all events can be cast as a BLP problem. The premise of this method is that the influences of different candidates are independent from each other, and are cumulative. This might result in a more conservative solution compared to regular DNEP approaches. The BLP is defined in (24), where $\mathbf{b}$ is a unitary vector with the size of the problematic elements. The inequality in (24) guarantees that the addition of influence scores VIS and CIS (represented in $\mathbf{A}$) from selected candidates (represented by $\mathbf{x}$), solve the issues in all problematic elements (represented by unitary vector $\mathbf{b}$. The global optimal is found with conventional solvers.

$$\begin{aligned} \text{minimise} \quad & \mathbf{c^T x} \\ \text{subject to} \quad & \mathbf{Ax} \geq \mathbf{b} \end{aligned} \tag{24}$$

IV. Case Studies and Numerical Results

This section presents the networks used to test the proposed methodology, and the relative results.

A. Studied topologies

1) IEEE 33-bus modified network: a radial feeder with 33 nodes that is often used for distribution network studies. The technical data paired with peak loads can be found in [36], [37]. The point of connection is modelled as the point of supply by the system operator, and the 32 remaining nodes represent aggregated low-voltage customers connected to the node through a distribution transformer.

2) Real Irish rural distribution network: radial rural feeder with 1171 buses from the West coast of Ireland was selected to represent more complex, unbalanced and extensive topologies [38]. 389 buses are loaded, 39 of these are three-phase. 484 three-phase and 615 single-phase branches compose the total 131.36 km in lines, while the furthest electrical point is 23.70 km away from the feeder. The peak active and reactive loads are 1728.6 kW and 591.6 kVAr respectively. This grid operates at 10 kV base voltage and presents significant voltage problems in its current state.

3) Forecasted demand and generation: for both feeders, the forecasted scenario selected for demand is given by a 250% increase for the target year, using the historical peak load reported in the documentation as a reference. This information

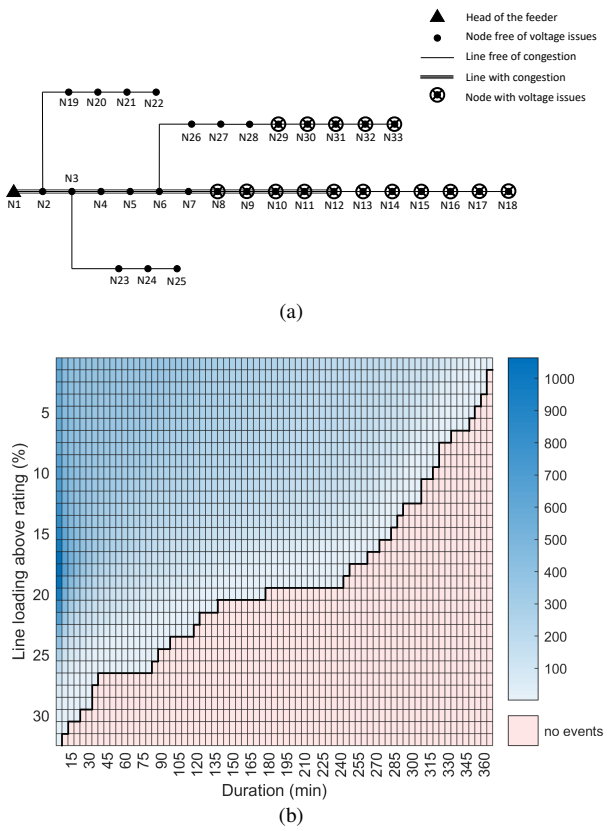

Fig. 2: Results of the preliminary analysis for the IEEE 33-bus network. (a) Topology highlighting voltage and line loading violation locations. (b) Heatmap with the numerical occurrence of line loading events at the most congested line L1 between N1 and N2.

is complemented using the CREST demand model [39] to generate synthetic profiles. Real utility data from the United Kingdom have been used to validate the model, which has been used in more than 300 distribution network studies. Reactive power is adjusted to match the power factor of each node in the documentation. With this model, year-long demand profiles with one-minute resolution equivalent to a leap year analogous to 2020 are produced for each node studied.

The forecasted generation profiles are produced with the respective functionality of the CREST model for photovoltaic (PV) production throughout the year. An expected growth of 250% in the installed generation capacity allocated in previous work by the authors in [38] was used as a reference. These demand and generation growth assumptions for the target year are realistic but purely illustrative, and they must be replaced by the system operator/designer/regulator forecast particular to the case they intend to study.

B. Preliminary analysis and candidate identification

A full ACPF simulation of the networks with forecasted demand and generation profiles was performed using OpenDSS. This results in networks with line congestion and voltage issues: 11 lines present congestion issues and 16 nodes present voltage issues for the IEEE 33-bus network (see Fig. 2a).

Based on the topology and these preliminary results of congestion and voltage issues for the IEEE 33-bus network, it is possible to determine the existence of 11 candidates for IU, 16 candidates for VR and 12 candidates for ESS. The event heatmap at a critical location is shown in Fig. 2b.

TABLE I
CANDIDATES DEFINED FOR THE DNEP: IEEE 33-BUS NETWORK

ID	Location	Type	Definition
1	Line 1	IU	New limit = 6,805 kVA (+34%)
2	Line 2	IU	New limit = 6,163 kVA (+22%)
3	Line 3	IU	New limit = 4,811 kVA (+52%)
4	Line 4	IU	New limit = 4,650 kVA (+47%)
5	Line 5	IU	New limit = 4,514 kVA (+43%)
6	Line 6	IU	New limit = 2,856 kVA (+50%)
7	Line 7	IU	New limit = 2,809 kVA (+48%)
8	Line 8	IU	New limit = 2,723 kVA (+43%)
9	Line 9	IU	New limit = 2,490 kVA (+31%)
10	Line 10	IU	New limit = 2,224 kVA (+17%)
11	Line 11	IU	New limit = 1,943 kVA (+2%)
12-27	Nodes 8-18, 29-33	VR	±10% Voltage range increase
28, 29	Nodes 1, 2	ESS	Cap. = 11.45 MWh, Dur. = 6.6h
30, 31	Nodes 3, 4	ESS	Cap. = 5.78 MWh, Dur. = 3.5h
32	Node 5	ESS	Cap. = 3.95 MWh, Dur. = 2.6h
33	Node 6	ESS	Cap. = 3.16 MWh, Dur. = 2.3h
34	Node 7	ESS	Cap. = 2.88 MWh, Dur. = 3.0h
35	Node 8	ESS	Cap. = 2.76 MWh, Dur. = 3.0h
36	Node 9	ESS	Cap. = 2.32 MWh, Dur. = 2.8h
37	Node 10	ESS	Cap. = 1.23 MWh, Dur. = 2.1h
38	Node 11	ESS	Cap. = 394 kWh, Dur. = 1.2h
39	Node 12	ESS	Cap. = 17.8 kWh, Dur. = 0.4h

The duration and intensity of events are used to size candidates. As an example, using the information on the congested line L1 available in Fig. 2b it is possible to size a candidate for IU (ID 1 in Table I) and for ESS (ID 28). The maximum intensity registered in the figure is 34.4% above the rating of L1 - which is 5,064 kVA. Therefore, the new rating of the upgraded conductor (ID 1) must be at least 6,805 kVA. Similarly, the charge or discharge rate from ESS that would solve the congestion issue in L1 corresponds to the difference between the new rating and the old one (i.e., 1,741 kVA charge/discharge rate). The maximum value obtained for the energy requirements for charge or discharge on a single day was 11.45 MWh. This can also be translated into an ESS duration of 6.6 hours. This process is repeated for all potential candidates considered for the IEEE 33-bus network, a summary of which is presented in Table I.

In the case of the Irish rural distribution feeder, the forecasted demand and generation results in a total of 1,079 nodes (92.2%) presenting voltage issues and 129 lines (11.0%) being congested. Considering the topology, this results in a total of 129 candidates for IU, 1,079 candidates for VR and 163 candidates for ESS. The candidates were sized using the methodology in Section III.

C. Prioritising candidates

Up to this point, the proposed methodology is technology-agnostic: for the case of VR and ESS, the technical benefits of candidates are assessed, but the particularities of the technology have not been considered This changes in the prioritisation of candidates: depending on the technology to analyse; the designer, policymaker or system operator must apply different efficiencies, depths of discharge, costs, etc.

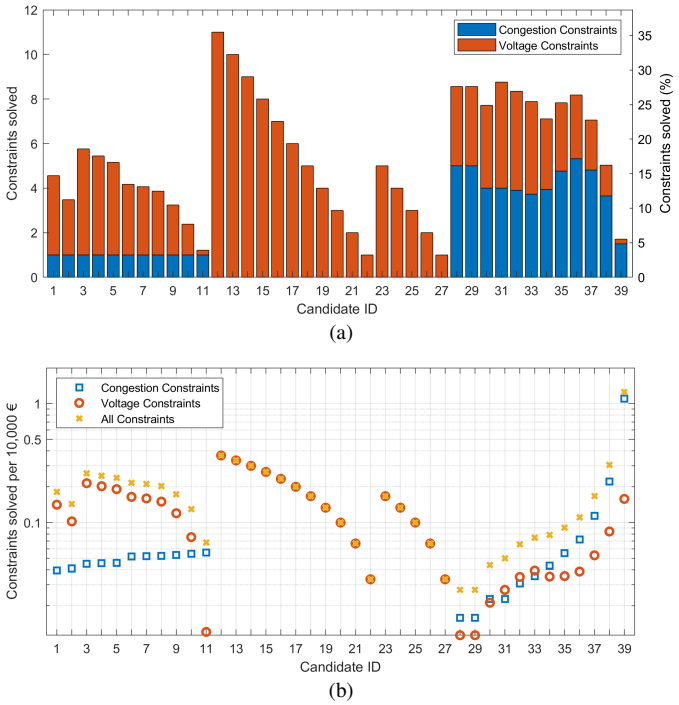

Fig. 3: Prioritisation of candidates. (a) Sum of congestion and voltage influence scores for each candidate, and (b) sum of influence scores for each candidate per 10,000 €, considering the high-cost projection for ESS.

A technology-specific assessment of candidates is not the purpose of this study: this paper will not extend to the technical and economic constraints for particular IU, VR and ESS technologies. Instead, for the purpose of this work and following current trends, VR will be modelled as OLTC with a ±10% bandwidth, and ESS as Li-Ion battery with a minimum state of charge of 20%. An analysis of sensitivity to ESS price was performed considering the high, mid and low-cost projections developed by the National Renewable Energy Laboratory in [40], [41]. Additional economic and technical assumptions can be found in [18], [41], [42].

The costs of installing, operating and maintaining each candidate in the planning timescale can be calculated and brought to present value considering local economic constraints. Fig. 3a presents how many issues each candidate solves on its own. Fig. 3b is a graphical representation of issues solved per cost unit. From the information in Fig. 3 it is possible to abstract that the best technical candidate is a VR in node 8 (ID 12) addressing events in 11 voltage-problematic elements. The best economic candidate is an ESS in node 12 (ID 39) addressing events in approximately one element per 10,000 € invested.

D. BLP solution

After defining, characterising and prioritising candidates, the minimum-cost list of candidates that solve all violation events of the network can be found using the BLP in (24). The **intlinprog** functionality of Matlab was used to find a solution, and the algorithm was run using a desktop PC equipped with an Intel Core i7, CPU at 2.3 GHz, and physical system memory of 16 GB. Three pools of candidates (i.e., cases) were considered to solve the BLP problem.

TABLE II
BLP SOLUTION FOR DIFFERENT CANDIDATE POOLS AND COST PROJECTIONS

Network	Cand. Pool	Cost Proj.	Candidates Chosen (ID)	Total costs (€)	Solving time (s)
IEEE 33-bus	Case 1	-	1-11	2,279,842	0.008
	Case 2	High	1-5, 37-39	1,755,473	0.013
		Mid	1-5, 37-39	1,653,630	0.009
		Low	1-5, 37-39	1,553,736	0.008
	Case 3	High	28, 31-33, 37-39	7,840,297	0.009
		Mid	28, 31-33, 37-39	6,307,234	0.010
		Low	28, 31-33, 37-39	5,045,787	0.009
Irish Rural Feeder	Case 1	-	129 (all) IU, 2 VR	14,450,940	0.055
	Case 2	High	36 ESS, 1 VR	831,620	4.910
		Mid	36 ESS, 1 VR	696,860	4.062
		Low	36 ESS, 1 VR	562,098	4.355
	Case 3	High	11 ESS	4,988,892	0.183
		Mid	11 ESS	3,402,886	0.172
		Low	11 ESS	2,459,615	0.173

- Case 1: Only IU and VR candidates are considered. This represents current practices and is the trivial solution to the DNEP as defined before. Each IU solves locally the congestion issues and partially remote voltage issues; this is complemented by localised VR.
- Case 2: All candidates are considered. A combination of IU upgrades, VR and ESS candidates can simultaneously address constraint violation events.
- Case 3: Only VR and ESS candidates are considered. This is a scenario that may be present in future planning problems: IUs are not a possibility due to technical or planning permission restrictions.

Table II presents the candidates selected for each case, together with the associated costs, and solving time. These results show that the candidates prioritised above as the best economic and technical ones are not necessarily part of the minimum-cost solution, highlighting that it is appropriate to use the BLP approach for candidate selection. Using a combination of candidate types (Case 2) the total costs associated are significantly reduced when compared to the traditional mechanism (Case 1) and the use of ESS and VR exclusively (Case 3). The last one results in a significantly more expensive result in all cost projection scenarios.

Using different cost projections for ESS does not result in radically different solutions, the same candidates are selected even if the total costs of the installation vary. Ultimately, the results of both studied topologies suggest that the proposed method is not highly sensitive to inputs and requires a small computational time. The advantages of the proposed method are highlighted when comparing these results with those reported by other authors as shown in Table III. Without considering pre-processing times for any, the proposed method finds a solution at least 277 times faster when comparing the 1171-bus West Ireland rural feeder (an extensive, complex and unbalanced network), to the 8-bus TN in [24].

Some references in Table III have power flow calculations embedded in their method. In contrast, the BLP method proposed runs power flows at the pre-processing stage. The comparison is not complete without including such pre-processing computational burden. The ACPF and influence

TABLE III
COMPARISON WITH OTHER METHODS IN THE LITERATURE

Ref.	Network(s) studied*	Data (timesteps)	Selected candidates	Solving time** [s]
BLP	33-bus DN	1 year (1m)	6 IU, 3 ESS	0.013
	1171-bus DN	1 year (1m)	36 ES, 1 VR	**4.91**
[22]	25-bus DN	8 days (15m)	2 IU, 1 ESS	66,996
	55-bus DN	8 days (15m)	2 IU, 1 ESS	70,812
	69-bus DN	8 days (15m)	2 IU, 1 ESS	307,008
	123-bus DN	8 days (15m)	2 IU, 1 ESS	299,016
[23]	28-bus DN	4 days (1h)	2 IU, 2 ESS	4,248
	28-bus DN	4 days (1h)	8 IU, 8 ESS	106,200
[24]	8-bus TN	24 days (1h)	1 IU, 1 ESS	**1,360.78**

* DN = distribution network, TN = transmission network
** Not including scenario reduction or data pre-processing run time

score calculations run time for the 33-bus and 1171-bus distribution networks studied is 18,925.7 and 117,338.4 seconds respectively, this is the same order of magnitude as one solution time of the other methods. The usefulness of the BLP approach is highlighted because of two reasons. First, when noting that the data set in this study is many times larger and has a considerably higher temporal resolution than those used in other methods. Second, when considering that this computationally-heavy pre-processing stage must be conducted only once for our method: after one run the BLP outperforms others.

V. TESTS AND VALIDATION

A year-long quasi-static time-series simulation of each resulting "future topology" consisting of selected IU, VR and ESS was performed for testing and validation (i.e., candidates chosen for each network, candidate pool and cost projection). IUs replaced old conductors (impedances and thermal limits from cable sizing were assumed continuous and were adjusted according to the IU), VRs were installed when selected, and Li-Ion ESS candidates configured for peak-shaving were connected. The results of this simulation confirm that the application of the selected candidates in all cases resolved all congestion and voltage issues. To extend on this, the medium cost projection of Case 2 for the IEEE 33-bus modified network is examined in detail.

This solution has a cost of 1,653,630 €, distributed as follows: 1,154,161 € (69.8%) for IUs, and 499,469 € (30.2%) for ESS installations - no VRs were part of this solution. Note that the network originally had 104,450 minutes of the year where at least one violation event occurs (i.e., 19.8% of the time there is at least one problem). Installing the selected candidates from the BLP (i.e., investing 1,653,630 €) 100% of constraint violation events are solved.

Fig. 4 shows that implementing the candidates at a reduced size solves fewer events. This suggests that if the system operator is willing to accept a network with some violation events, investments can be reduced significantly. To have a network with less than 2% of problematic instances of the year (i.e., reducing existing congestion and voltage issues by 10%), the size of IU candidates can be reduced to 70% and of ESS candidates to 50%. This reduction represents an investment of 1,057,487 € - approximately 36% less. Note how for this

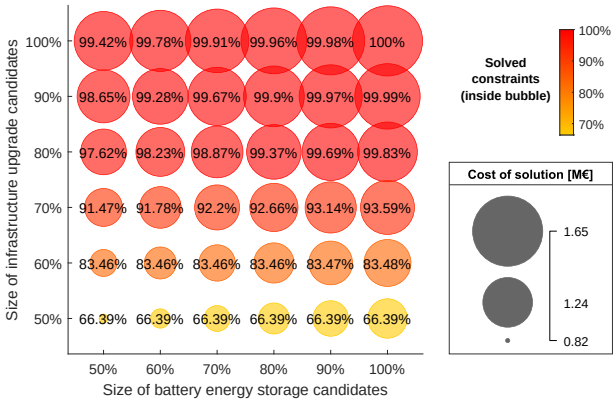

Fig. 4: Percentage of constraint violation events solved for different candidate sizing.

case, reducing the size of the installed IU results in more constraint violation events compared to reducing the size of ESS candidates. IUs appear to play a larger role in solving violation events for this particular network.

It is important to highlight the versatility of the proposed method: a designer can add customised candidates or remove those less relevant/feasible. The influence scores of alternative candidates can also be calculated and integrated into a new BLP for alternative solutions. Since the computational time is modest, the designer has significant flexibility on how the problem is approached (i.e., multiple pools of candidates can be evaluated faster). Furthermore, this method can be used to contrast different technologies: once technology-agnostic candidates are sized, economic and technical considerations can be compared for different technology specifications (e.g., comparing Li-Ion, sodium sulphur, and lead acid ESS).

VI. CONCLUSION

This work presents a numerical method to define a list of minimum-cost candidates (i.e., IU, VR and ESS) based on forecasted constraint violation events. The proposed methodology presents reduced computational time, has low sensitivity to inputs and has been validated through extensive simulation work using two distribution networks. The results suggest that applying the BLP solution solves 100% of forecasted violation events. It was found that a combination of the three types of candidates solves events at a lower total cost compared to using a single candidate type. A study of this nature is particularly useful for system operators, planners and designers because it makes it possible to run multiple simulations in little time. Numerous candidate pools can be tested, including customised IU, VR and ESS installations and different technologies.

The authors foresee the addition of three layers of complexity to the method in future work. The first addresses the main limitation of this work: a potentially overly conservative investment. This is possible by adjusting candidate sizes following the "time dimension" given by power quality standards (e.g., EN50160 [43]), where constraint violation events are tolerable for a short duration. It is straightforward

to adjust the proposed methodology to solve less than 100% of constraint violation events if their time duration is limited. Such an adjustment is non-trivial for MILP-based DNEPs, in which complicating constraints would be needed. Secondly, it is possible to replace manufacturer's line ratings to include weather-dependent dynamic line ratings. Ultimately, this work can be further developed if it is cast for multiple planning steps. If the forecasted demand and generation information is available for different discrete moments over a planning horizon, each discrete value provides an answer on which candidates have priority in the short and medium term. The candidates selected in a discrete-time step can become part of the "current topology" for subsequent time steps.

REFERENCES

[1] M. A. Akbari *et al.*, "New metrics for evaluating technical benefits and risks of dgs increasing penetration," *IEEE Trans. Smart Grid*, vol. 8, no. 6, pp. 2890–2902, 2017.

[2] L. Mehigan *et al.*, "Synergies between low carbon technologies in a large-scale mv/lv distribution system," *IEEE Access*, vol. 10, pp. 88 655–88 666, 2022.

[3] X. Xu *et al.*, "Upgrading conventional distribution networks by actively planning distributed generation based on virtual microgrids," *IEEE Systems Journal*, vol. 15, no. 2, pp. 2607–2618, 2021.

[4] X. Zhang *et al.*, "Research on active distribution network structure planning for multi distributed generation access," in *IEEE 4th Conf. on Energy Internet and Energy System Integration*, 2020, pp. 2197–2202.

[5] P. Gautam, P. Piya, and R. Karki, "Resilience assessment of distribution systems integrated with distributed energy resources," *IEEE Trans. Sustain. Energy*, vol. 12, no. 1, pp. 338–348, 2021.

[6] G. Migliavacca *et al.*, "The innovative flexplan grid-planning methodology: How storage and flexible resources could help in de-bottlenecking the european system," *Energies*, vol. 14, no. 4, 2021.

[7] V. Vahidinasab *et al.*, "Overview of electric energy distribution networks expansion planning," *IEEE Access*, vol. 8, pp. 34 750–34 769, 2020.

[8] S. Claeys, M. Vanin, F. Geth, and G. Deconinck, "Applications of optimization models for electricity distribution networks," *WIREs Energy and Environment*, vol. 10, no. 5, p. e401, 2021.

[9] J. D. Bouford, J. M. Teixeira, and C. A. Warren, "The natural replacement process versus the aging infrastructure of distribution poles," *IEEE Trans. Power Deliv.*, vol. 23, no. 3, pp. 1522–1526, 2008.

[10] J. Haakana, T. Kaipia, J. Lassila, and J. Partanen, "Reserve power arrangements in rural area underground cable networks," *IEEE Trans. Power Deliv.*, vol. 29, no. 2, pp. 589–597, 2014.

[11] G. Pall, et al., "Causes of delay in power transmission projects: An empirical study," *Energies*, vol. 13, no. 1, 2020.

[12] G. K. Pall, A. J. Bridge, M. Skitmore, and J. Gray, "Comprehensive review of delays in power transmission projects," *IET Generation, Transmission & Distribution*, vol. 10, no. 14, pp. 3393–3404, 2016.

[13] J. Massignan, B. Pereira, and J. London, "Load flow calculation with voltage regulators bidirectional mode and distributed generation," *IEEE Trans. Power Syst.*, vol. 32, no. 2, pp. 1576–1577, 2017.

[14] J. Contreras-Ocaña, Y. Chen, U. Siddiqi, and B. Zhang, "Non-wire alternatives: An additional value stream for distributed energy resources," *IEEE Trans. Sustain. Energy*, vol. 11, no. 3, pp. 1287–1299, 2020.

[15] N. Gal, A. Navon, G. Ben Yosef, Y. Levron, and J. Belikov, "Storage for grid deferral: The case of israel," in *2021 IEEE PES Innovative Smart Grid Technologies Europe (ISGT Europe)*, 2021, pp. 1–5.

[16] B. Thormann and T. Kienberger, "Estimation of grid reinforcement costs triggered by future grid customers: Influence of the quantification method (scaling vs. large-scale simulation) and coincidence factors (single vs. multiple application)," *Energies*, vol. 15, no. 4, 2022.

[17] "Grid codes for renewable powered systems," International Renewable Energy Agency, Tech. Rep., 2022. [Online]. Available: https://www.irena.org/publications/2022/Apr/Grid-codes-for-renewable-powered-systems

[18] "IEEE guide for voltage regulation and reactive power compensation at 1000 kv ac and above," *IEEE Std 1860-2014*, pp. 1–41, 2014.

[19] M. Nijhuis, M. Babar, M. Gibescu, and S. Cobben, "Demand response: Social welfare maximization in an unbundled energy market case study for the low-voltage networks of a distribution network operator in the netherlands," *IEEE Trans. Ind. Appl.*, vol. 53, no. 1, pp. 32–38, 2017.

[20] R. Faia, B. Canizes, P. Faria, and Z. Vale, "Distribution network expansion planning considering the flexibility value for distribution system operator," in *SEST conference*, 2019, pp. 1–6.

[21] Y. Guo, Q. Zhang, and Z. Wang, "Cooperative peak shaving and voltage regulation in unbalanced distribution feeders," *IEEE Trans. Power Syst.*, vol. 36, no. 6, pp. 5235–5244, 2021.

[22] J. Yi et al., "Optimal co-planning of esss and line reinforcement considering the dispatchability of active distribution networks," *IEEE Trans. Power Syst.*, vol. 38, no. 3, pp. 2485–2499, 2023.

[23] ——, "Expansion planning of active distribution networks achieving their dispatchability via energy storage systems," *Applied Energy*, vol. 326, p. 119942, 2022.

[24] A. J. Conejo, Y. Cheng, N. Zhang, and C. Kang, "Long-term coordination of transmission and storage to integrate wind power," *CSEE Journal of Power and Energy Systems*, vol. 3, no. 1, pp. 36–43, 2017.

[25] M. Jooshaki *et al.*, "An enhanced milp model for multistage reliability-constrained distribution network expansion planning," *IEEE Transactions on Power Systems*, vol. 37, no. 1, pp. 118–131, 2022.

[26] Z. Lin, Z. Hu, and Y. Song, "Distribution network expansion planning considering $n-1$ criterion," *IEEE Transactions on Power Systems*, vol. 34, no. 3, pp. 2476–2478, 2019.

[27] Z. Li, W. Wu, X. Tai, and B. Zhang, "A reliability-constrained expansion planning model for mesh distribution networks," *IEEE Transactions on Power Systems*, vol. 36, no. 2, pp. 948–960, 2021.

[28] N. Amjady, A. Attarha, S. Dehghan, and A. J. Conejo, "Adaptive robust expansion planning for a distribution network with ders," *IEEE Transactions on Power Systems*, vol. 33, no. 2, pp. 1698–1715, 2018.

[29] S. Hardy, H. Ergun, and D. Van Hertem, "A greedy algorithm for optimizing offshore wind transmission topologies," *IEEE Transactions on Power Systems*, vol. 37, no. 3, pp. 2113–2121, 2022.

[30] C. Silveira, et al., "Mathematical optimization versus metaheuristic techniques: A performance comparison for reconfiguration of distribution systems," *Electric Power Systems Research*, vol. 196, p. 107272, 2021.

[31] International Electrotechnical Commission (IEC), "Electromagnetic compatibility (emc)-part 4-30: Testing and measurement techniques-power quality measurement methods," *IEC 61000-4-30*, 2003.

[32] D. Montenegro and R. Dugan, "Simplified a-diakoptics for accelerating qsts simulations," *Energies*, vol. 15, no. 6, 2022. [Online]. Available: https://www.mdpi.com/1996-1073/15/6/2051

[33] A. Koirala *et al.*, "Chance-constrained optimization based pv hosting capacity calculation using general polynomial chaos," *IEEE Trans. Power Syst.*, pp. 1–12, 2023.

[34] E. Mora and F. Steinke, "Robust voltage regulation for active distribution networks with imperfect observability," in *2021 IEEE Madrid PowerTech*, 2021, pp. 1–6.

[35] B. B. Adetokun, J. O. Ojo, and C. M. Muriithi, "Reactive power-voltage-based voltage instability sensitivity indices for power grid with increasing renewable energy penetration," *IEEE Access*, vol. 8, pp. 85 401–85 410, 2020.

[36] V. Vita, "Development of a decision-making algorithm for the optimum size and placement of distributed generation units in distribution networks," *Energies*, vol. 10, no. 9, 2017.

[37] N. Kanwar, N. Gupta, K. Niazi, and A. Swarnkar, "Improved meta-heuristic techniques for simultaneous capacitor and DG allocation in radial distribution networks," *International Journal of Electrical Power & Energy Systems*, vol. 73, pp. 653–664, 2015.

[38] J. J. Cuenca and B. P. Hayes, "Non-bias allocation of export capacity for distribution network planning with high distributed energy resource integration," *IEEE Trans. Power Syst.*, vol. 37, no. 4, pp. 3026–3035, 2022.

[39] E. McKenna and M. Thomson, "High-resolution stochastic integrated thermal–electrical domestic demand model," *Applied Energy*, vol. 165, pp. 445–461, 2016.

[40] C. Wesley, A. W. Frazier, and C. Augustine, "Cost projections for utilityscale battery storage: 2021 update," National Renewable Energy Laboratory, Tech. Rep. NREL/TP-6A20-79236, 2021. [Online]. Available: https://www.nrel.gov/docs/fy21osti/79236.pdf

[41] K. Horowitz, "2019 distribution system upgrade unit cost database current version." [Online]. Available: https://data.nrel.gov/submissions/101

[42] "Voltage regulators reference data: Voltage regulators vs. load tap changers," EATON, Tech. Rep. TD225012EN, 2017. [Online]. Available: https://www.eaton.com/content/dam/eaton/products/medium-voltage-power-distribution-control-systems/voltage-regulators/voltage-regulators-vs-load-tap-changers-information-td225012en.pdf

[43] C. Masetti, "Revision of european standard en 50160 on power quality: Reasons and solutions," in *Proceedings of 14th International Conference on Harmonics and Quality of Power - ICHQP 2010*, 2010, pp. 1–7.