A CENTRALIZED CONTROL FOR THE OPERATION OF LOW VOLTAGE DISTRIBUTION NETWORKS WITH MULTIPLE DISTRIBUTED ENERGY RESOURCES

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ABSTRACT

This paper proposes a secondary substation centered control approach which deals with the effective coordination of multiple Distributed Energy Resources (DER) connected along the LV grid. The presented tool manages and schedules the flexibilities (i.e. active and reactive power injection or absorption) provided by DER in order to address overvoltages or voltage sags, while minimizing operational costs. The methodology is based on a three-phase multiperiod optimal power flow. The proposed control scheme is assessed within an IEEE - LV benchmarked network considering different scenarios of Electric Vehicle and microgeneration integration as well as a centralized battery owned by the grid operator.

INTRODUCTION

Traditionally, Low Voltage (LV) distribution networks used to be the most passive circuits within the power systems, since the power flows were solely headed from distribution transformers to consumers without the operation of automation elements [1]. In particular, the entire segment from the secondary substation and its downstream connected LV network is very often not monitored nor controlled.

Nowadays, the increasing integration of Distributed Energy Resources (DER) along the distribution networks is posing several technical challenges. The Distribution System Operators (DSOs) address such technical challenges by increasing the observability and controllability of the grids, envisioning the active management of the DERs for ancillary services, through new operation stages.

The active network management through the engagement of DERs in the operation of the grid is also regarded to occur with the provision of support to tackle technical challenges (i.e. provoked by massive DER integration). Such control typically refers to the control of active and reactive power of DERs, based mainly on the flexibility they provide.

A particular concern in current research explores the potential flexibility provided by the DER connected along the distribution level (i.e. Medium Voltage and LV). The connection of such resources at the LV grid and end-users' premises is foreseen to increase substantially in the near future with small rooftop installations usually coupled with Battery Energy Storage System (BESS), controllable loads (e.g. electric water heaters) and Electric Vehicles (EVs). Therefore, it is critical to exploit the DER controllability and active participation through demand response schemes in order to support or even optimize the network operation.

Recent studies have addressed the possibility of considering Low Voltage (LV) controllable assets beyond DSO assets, such as distributed BESS, controllable loads under demand response schemes and micro-generation units such as PV units [2].

Particular focus has been given in aggregating flexible resources connected along the LV grid to support the operation of MV networks, by considering the LV grid as a flexible cluster. Advanced methodologies need to be implemented to determine control actions related to controllable DER, which can improve the performance and operation of distribution networks, delivering benefits to residential users. Several studies focus on the potential impacts and flexibility of DER -mainly EV and BESS-, implying their potential active management for operational purposes.

Recent works [3, 4], have proposed advanced schemes that address the operation of the grid by setting linear approximations to power flow equations for setting tractable multiperiod Optimal Power Flow (OPF) schemes, although focused on single-phase analysis of the distribution grid. This is not adequate, since LV grids are typically multi-phase (i.e. 3-phase with coupling among active conductors); facing unbalanced conditions due to the untransposed lines, single-phase loads and single-phase microgeneration.

In this work a conceptual secondary substation centered control approach is proposed, which aims to coordinate DER in favor of the technical operation of the LV grid. The proposed tool relies on the exact formulation of a multi-period three phase AC-OPF scheme, taking advantage of the availability of DER to improve the operation of the LV grid. The operational tool is meant to be adopted in the technical architecture proposed in [5, 6].

CENTRALIZED CONTROL SCHEME

Multi-period 3-phase OPF for LV grid

The proposed centralized operation tool is mathematically stated in this section. The vector $[x_\tau]$ expresses the state vectors of the grid (i.e. voltage magnitude and angle) at each time step $\tau \in \mathcal{T}$, where $\mathcal{T} = \{1, \dots, H_\tau\}$ and H_τ the length of the horizon of optimization. The voltage angles can be omitted to reduce the scale of the optimization problem, since the angle displacement between adjacent nodes in LV grids is typically less than 10° [5].

Let us consider the stacked vector $\mathcal{U} = [u_1, \dots, u_{H\tau}]$, containing the subsequent control vectors u_τ per each period for all controllable DER and assets. The u_τ essentially contains the active and reactive power set points for all controllable units. Penalty costs are assigned to auxiliary variables described with the term *Aux* in the objective function. Such penalty costs refer to relaxation of voltage bounds to ensure feasibility and thus, convergence, as well as penalties to avert simultaneous charging and discharging. The set phases, the set of branches of the network and the set of nodes are respectively denoted as follows Φ, $\mathcal{J}$, $\mathcal{N}$. Therefore, the three phase multi-period OPF problem is posed by (1):

$$\min_{u} f = \min_{\mathrm{u_t}} \sum_{\tau}^{H_t} \left\{ \sum_{\mathrm{j=1}}^{\mathrm{n_g}} \left(c_j^T(\tau) \cdot u_j(\tau) \right) \right\} \Delta\tau + \mathrm{Aux} \quad (1)$$

subjected to

$$F_{j,\varphi}(x,u) = 0 \qquad \forall j,\varphi \in \mathcal{N},\Phi \quad (1a)$$

$$\underline{V} - \varepsilon_V \leq V_{j,\varphi}(x_\tau) \leq \overline{V} + \varepsilon_V \qquad \forall j,\varphi \in \mathcal{N},\Phi \quad (1b)$$

$$g_\mu(x_\tau, u_\tau) = 0 \qquad \forall \mu \in \mathcal{U} \quad (1c)$$

$$h_\mu(x_\tau, u_\tau) \leq 0 \qquad \forall \mu \in \mathcal{U} \quad (1d)$$

where the constraints in (1a) set the three-phase power balances at each bus of the network; (1b) to respect all nodal voltages that range strictly within the admissible bounds (ε_V is used to fairly relax the bounds and avoid infeasibility). The generalized equality and inequality constraints (1c-d), correspond to the operational limits of the controllable DER, which vary according to the type of DER. The gradient of the objective function, the Jacobian of nonlinear constraints and Hessian of the Lagrangian are implicitly provided to the optimizer, thus, improving notably the convergence time. The presented optimization problem corresponds to a non-linear optimization problem with convex objective function.

DER Models

A brief discussion follows concerning the DER models and assertions made for the presented study.

Battery Energy Storage System (BESS)

The BESS model is based on a first order model. Two auxiliary variables are settled as power injections. The positive term refers to the discharging mode $p_{ds} \geq 0$, $p_{dch} \epsilon \mathbb{R}$, while the charging of the storage unit is negative $p_{ch} \leq 0,\ p_{ch} \epsilon \mathbb{R}$. Assuming that the charging

$$\epsilon_{\tau+1} = \epsilon_\tau - \Delta\tau \, [\eta_{ch} \;\; 1/\eta_{dch}] \, p(\tau) \qquad (2)$$

$$p(\tau) = \begin{bmatrix} p_{ch} \\ p_{dch} \end{bmatrix}$$

where η_{ch}, η_{ds} corresponds to the charging and discharging efficiencies.

In the proposed optimization framework, as primary decision variable for each BESS is considered its power injection P_{BSS},which should be subjected to the equality constraint (3a) for each instant τ.

$$P_{BESS}(\tau) = p_{ch}(\tau) + p_{dch}(\tau) \qquad (3a)$$

$$\overline{p_{ch}} \leq p_{ch}(\tau) \leq 0 \qquad (3b)$$

$$0 \leq p_{dch}(\tau) \leq \overline{p_{dch}} \qquad (3c)$$

$$\underline{SoC} \leq SoC(\tau) \leq \overline{SoC} \qquad (3d)$$

$$SOC(\tau) = \frac{\epsilon(\tau)}{\epsilon_{rated}} \qquad (3e)$$

(3a-e) are set $\forall \boldsymbol{\tau} \in \boldsymbol{\mathcal{T}}$. The constraints (3a-e) define the technical constraints for the BESS charging and discharging power. Accordingly, the State of the Charge (SoC) -defined in equation (3e) - is constrained based on the BESS characteristics. To avert simultaneous charging and discharging of the BESS, a penalty cost is assigned with the auxiliary decision variables $\boldsymbol{p_{ch}}$, $\boldsymbol{p_{dch}}$ greater -at least one order-than the use of the BESS ($\boldsymbol{c_{BESS}}$) itself.

The energy state of BESS -equality constraint- (2) together with the inequality constraint pose the intertemporal couplings since they are applied for all τ.

As additional note, for a three-phase BESS in this study the same mathematical formulation is followed, although setting the assertion that all phases follow the same mode of operation.

Electrical Vehicle (EV)

Regarding EVs, they are structured following the same rationale as the BESS. Their provided flexibility is essentially considered to be the intervals when they are parked to the owner's house premises. A fictitious variable is added to discharge the EVs during their trips. When the owner of an EV desires to provide a signal of flexibility, the time interval when the estimated trip will occur together with the estimated consumed energy should be dispatched to the DSO. These two signals are captured with $[\boldsymbol{y_{trip}}]_{n_{tr} \times H_\tau}$ and E_{tr}, where n_{tr} corresponds to the number of trips for an EV.

One can define the energy for each instant for an EV given by the vector $\epsilon_{EV} \in \mathbb{R}^{H_\tau}$ by equation (5a), which substantially infers to a linear combination of preceding instances inherent to the controllability that the flexibility allows, and the initial stored energy.

$$\epsilon_{EV} = \begin{bmatrix} \epsilon_0 \\ \vdots \\ \epsilon_0 \end{bmatrix} + \begin{bmatrix} \Lambda & & & \\ \Lambda & \Lambda & & \\ \vdots & \vdots & \ddots & \\ \Lambda & \cdots & \cdots & \Lambda \end{bmatrix} \begin{bmatrix} p_{(1)} \\ \vdots \\ p_{(H\tau)} \end{bmatrix} - [y_{trip}] E_{tr} \quad (5a)$$

$$\begin{bmatrix} \epsilon_s \\ \vdots \\ \epsilon_s \end{bmatrix} \leq \epsilon_{EV} \leq \begin{bmatrix} \epsilon_s \\ \vdots \\ \epsilon_s \end{bmatrix} \qquad (5b)$$

$$\Lambda = -\Delta\tau \left[\eta_{ch} \;\; \frac{1}{\eta_{dsc}} \right] \qquad (5c)$$

The EVs are subjected to the same technical constraints as

the BESS. When the V2G operation mode is not applied the p_{dch} is simply set to zero.
Two EV charging strategies are hereby considered:

- "Dumb" charging or uncontrolled charging where the EVs are not incorporated within the proposed operational scheme.
- "Smart" charging, where the EV owner communicates relevant data (i.e. flexibility as defined above) regarding commute and accordingly its availability to be charged according to the proposed tool. The V2G mode services enables the option to utilize the EV essentially for grid services.

These constraints are automatically incorporated in the multiperiod-OPF scheme as the generalized set of equations (1d-e), whenever the availability of the EV allows it. The availability of the EV to charge, is considered along the day during their idle periods.

Microgeneration - PV Installations

The microgeneration in this work is considered to be single phase PV rooftop installations. In case the DSO chooses to incorporate the control of PV installations in the scheduling tool, opting the type of control active power through curtailment of active power (*PAC*) or Reactive Power Control (*QR*).
Regarding the PAC the following settings define the maximum possible curtailed power as a percentage to the instant injected power (i.e. maximum curtailment β=20%), given the following rule in equation (6).

$$\overline{p_{pac}(\tau)} = \begin{cases} \beta \cdot p_{inj}(\tau), & \textbf{if } p_{inj}(\tau) \geq \xi \cdot p_{rated} \\ 0, & \textbf{else} \end{cases} \quad (6)$$

ξ (in this study ξ=0.5) stands for a parameter which leads to control PV with more notable injected power at the instant period in proportion to their installed power.
The reactive power control is defined in similarly, though allowing capacity and inductive operation (i.e. injecting and absorbing reactive power accordingly). Nevertheless, if the option of controlling the PVs in both PAC and QR mode, to avoid the nonlinear constraint (7) inherent to the operation of the inverter; a simplified linear constraint is posed to ensure that the microgenerators' inverter do not exceed its rated power.

$$\overline{Q_{pv}} = \left(p_{rated} - \overline{p_{pac}(\tau)}\right) \tan\theta \quad (7)$$

CASE STUDY SYNOPSIS AND RESULTS

The network selected as a case study to perform the validation of the proposed scheme belongs to the IEEE benchmarked LV European network [7]. The network corresponds to a real low voltage feeder connected to the MV grid through a transformer of nominal power 800kVA which steps the voltage down from 11kV to 416V. The service cables are also included in the grid representation, while there are 55 residential consumers connected along the grid. In all scenarios, a three-phase centralized BESS is assumed to be connected to adjacent to the secondary substation (node 2) and, alternatively, at node 101 (Figure 1). The BESS capacity is 135kWh and the maximum charging and discharging rate is 75kW. This BESS is assumed to have an initial SoC of 0.65 with $\underline{SoC}$=0.1 and at the end of the optimization horizon it has to be equal to the initial, $SoC_{H\tau}$=0.65. The power factor of this centralized BESS is considered as unitary in all the simulations.

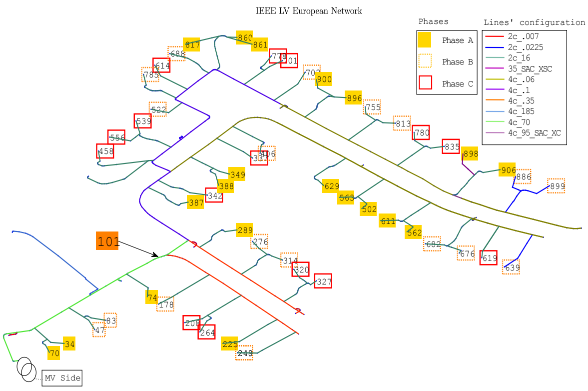

Figure 1 IEEE Low Voltage grid test case.

The load and the microgeneration profiles used correspond to daily data for a summer period, which are extrapolated from realistic data pool provided for the benchmarked grid. All the consumers are single-phase and their phase connection is depicted on Figure 1. All the microgeneration units are considered as single-phase PV rooftop installations which are connected to the same phase as the respective residential user.
The electric vehicles used for the simulated study are based on 4 different EV models Nissan Leaf, Chevrolet Volt, BMW i3, Tesla S which present different technical features regarding the Battery Capacity and charging

Table 1 Electric Vehicles models and characteristics.

EV Model	Battery Capacity [kWh]	Charging Power [kW]	Driving Efficiency (km/kWh)	End user connection	
				Scenario C3	Scenario C4
Nissan Leaf	24	4	6.7	47.2/264.3/562.1/629.1	264.3
Chevrolet Volt	16	3.75	3.75	83.2/314.2/682.2/688.2	458.3
BMW i3	22	11	7.2	208.3/337.3/70.1	349.1/249.2
Tesla S	60	11	6.7	248.2/406.2/556.3	563.1/289.1

power as well as the driving efficiency. Their characteristics are listed in Table 1.
All Tesla S and BMW i3 models are considered to be charged with Efacec HomeCharger 7.4kVA, while the rest EVs are charged through an Efacec HomeCharger 3.4kVA EV. Therefore, the maximum charging power in each case is driven by the charger used.
Concerning the EV usage, a routine is built to emulate credible scenarios which is fed with public data by [8]. The aforementioned routine aims to capture patterns in the EV usage upon different trip purposes and the trip duration (min) and length (km). The resulting data reflect a realistic response for the EV behavior during a day of operation, standing on the assertion that EVs charge exclusively at home.
For the case where EVs follow the dumb charging, their charging occurs based on the distribution function given by [9].
The time departure and arrival as well as the daily distance traveled by each are randomly selected for a summer day.
The following assumptions are also regarded for the EV:

- Initial SoC for all Nissan Leaf SoC_0=0.55, for all Chevrolet Volt SOC_0=0.65, for all BMW i3 SoC_0=0.45 and for all Tesla S SoC_0=0.40. All EVs are meant to have to same SoC as their initial state for the end of the horizon (H_τ).
- The charging efficiency and discharging -when V2G- efficiency are 95% for all EVs.

According to the standard EN-50160, the 10 min mean r.m.s voltages shall not exceed the statutory limits during 95% of the week. Meanwhile, all 10 min mean r.m.s voltages shall not exceed the range of the Vn% + 10% and Vn%–15% (which corresponds to 253 V and 195.5 V for most European grids). Given the fact that the proposed control scheme uses 30-min averaged data resolution, the voltage limits are set in [0.95, 1.05] p.u.values.
The scenarios analyzed in this study are described in Table 2, where the percentage of PV and EV integration refers to the proportion of end users that own such units. For instance, 25% of EV penetration (i.e. 14 EVs), where the charging point of the EV are indicated on last column of Table 2.
All scenarios consider that all DER provide certain degree of flexibility as explained in the previous sections and the proposed tool validates the coordination of the DER to tackle voltage problems met.

The use of DER is prioritized through the weighted terms c_j, in the sense that the operational tool attempts to manage the flexibilities by addressing any voltage issues with the controllable DER assigned with the lowest c_j. These c_j can be attributed with real operational cost values to reflect monetary values for the use of flexibility. Nevertheless, for this study the weighted terms derive the priority of use settled as $c_{cBSS} < c_{EV} < c_{PAC} < c_{QR}$. In this way the tool prioritizes the use of the centralized BESS which belongs to the DSO; avoids excessive active power curtailments and the presence of the EVs restrain the dispatch of reactive power by the PVs which is rather not effective for addressing voltage issues in LV grids (i.e. r>x).

Cases C1-C2

In scenario C1, -with 25% of PV integration- overvoltages are observed along the grid due to notable active power injections. The control scheme in the C1a where the centralized $BESS_2$ is connected close to the secondary substation addresses the overvoltages by efficiently curtailing active power -in total 4.25 kWh- (Figure 2a).

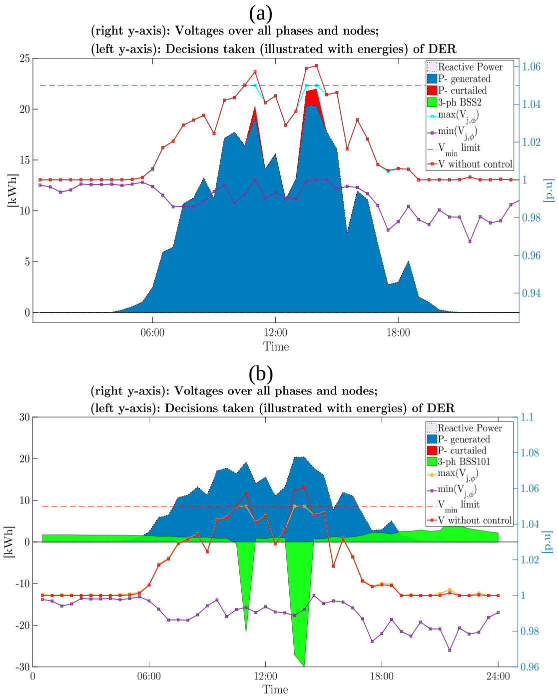

Figure 2 Extreme voltages over all phases and nodes; DER state along 24-hours for scenario (a) C1a and (b). C1b.

Table 2 Scenarios definition; results regarding active curtailments.

DER	C1a	C1b	C2a	C2b	C3a	C3b	C4a	C4b
PV	25%	25%	45%	45%	25%	25%	45%	45%
EV	0	0	0%	0%	25%	25%	35%	35%
Centralized BESS [Connection Point]	2	101	2	101	2	101	2	101
Curtailed Energy [kWh]	4.25	0.1	9.57	1.66	3.7	0	5.1	0

In contrast to scenario C1b (Figure 2b), indicates that the -electrical- adjacency of the centralized $BESS_{101}$ to the nodes with that face overvoltages, lead to the voltage mitigation with curtailing only 0.1kWh of energy produced by PVs; thus, deriving a daily schedule for centralized $BESS_{101}$,which is presented in Figure 3.

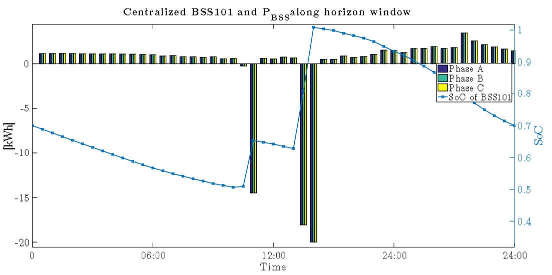

Figure 3 Control setpoints for BESS101 at scenario C1b, for the 24-h.

In scenario C2a-b it is observed that the centralized BESS is not sufficient to mitigate the voltages. Therefore, the proposed tool decides for the coordinated operation of the BESS together with active power curtailments. From Table it can be seen that for C2b the curtailed energy is about 9.5kWh less due to the presence of $BESS_{101}$.

Cases C3-C4

Both scenarios C3-C4 consider the EV integration. In these cases, all the integrated EV are settled to flexible in the sense that they are include in the proposed scheme. Therefore, it is observed that the more the EVs along the grid the lesser the power active curtailments are. In particular, for scenario C3a, the tool decides an alternative smart charging profile (i.e. compared to the dumb which is also represented), which essentially shifts the available EV to be charged during sunny periods 11:00 – 13:00, which leads to alleviating the overvoltages as well (Figure 4). The latter, results to the regulation of all nodal voltages with reduced active power curtailments compared to the C2a. The same observation can be noticed for C4a. Most importantly, the coordinated operation of all the DER derived by the operational tool in C3b and C4b yields zero active power curtailments. This occurs due to the more efficient placement of the BESS at node 101 in addition to the smart charging of the EVs. The charging of the available EVs (i.e. parked at dwellings) is decided by the tool to take place during overvoltage periods.

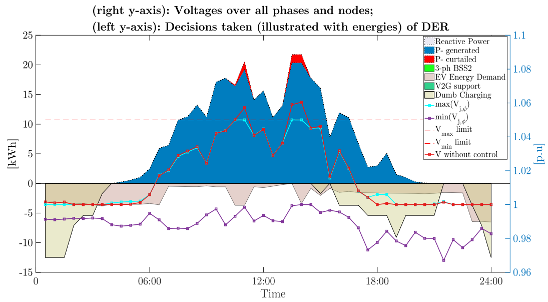

Figure 4 Extreme voltages over all phases and nodes; DER state along 24-hours for scenario C3a.

For all simulated cases, one can conclude that the radial configuration of LV networks present overvoltage issues particularly in buses -electrically- furthest from the substation since the high resistivity of the lines contributes to the aggravation of them. In addition, distant nodes at ending point might face significant voltage drops (i.e. if EVs are present) or even overvoltages (i.e. if PVs are present). Therefore, the placement of a centralized BESS in proper location along the grid is rather crucial.

This work presents a tool which is capable to provide support to the DSO decision for the operation of LV distribution grids with increased integration of DER. The proposed centralized scheme ensures admissible voltage profiles by minimizing the active power curtailments of microgeneration through the coordination of DER; maximizing, in this sense the integration of microgeneration. Nonetheless, the scheme can be deployed only by the subsequent communication technologies (for online implementation), together with forecasted data and power flow-state estimation tools.

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