

Coordinated Dynamic Use of Dispersed Flexibility to Maximize the Time-variant Aggregated Potential for Redispatch

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Abstract: During recent years, the European interconnected transmission system has been affected by a significant increase of grid congestion. Nowadays, large-scaled power plants are providing redispatch power, but will be phased out in coming decades. Besides this development, new technologies like renewable energies or battery storage systems emerged in power systems. These technologies are typically small-scaled, dispersed and connected to distribution systems. Dispersed generation units, storage systems, electric vehicles, and controllable loads may be capable of providing flexible power. Coordinated dynamic use of flexible power from large numbers of small units could become a key contribution to cope with grid congestion in the future. The paper presents a methodology to determine the maximum, time-variant potential for redispatch of distributed units aggregated in a virtual power plant. It is based on parameter-based optimization and takes into account dynamic and energy capacity related constraints. Moreover, the constraints of distribution and transmission systems as well as the impact on power flows is considered and investigated for multiple scenarios by using linearized power flow sensitivities.

Keywords: electrical networks, electric power systems, energy storage, power control, energy distribution, congestion management, virtual power plant, dispersed flexibility, optimization

1. INTRODUCTION

Congestion management is a system service performed by system operators, typically transmission system operators (TSO), to secure network stability. It must be considered as a non-standardized procedure. Within this paper we refer to the situation in Europe (Van den Bergh et al. (2015)) and particular in Germany (Netztransparenz (2019)). Nevertheless, our proposed methodology is set up as a generic procedure to be not dependent on the German regulatory framework. In general, units which are able to operate at given power set points over a defined period of time are at the disposal of TSOs for congestion management, primarily for measures such as redispatch. In Germany this is, at least theoretically, mandatory for units with an installed capacity over 100 kW.

In recent years, the demand for redispatch increased significantly in Germany, especially in situations with high generation and load profiles. Cost-intensive curtailment of renewable energies (RES) is also required frequently. Moreover, this is intensified by higher distances between power generation, especially of wind power in the north, and consumption centers in the south as well as continuously raising trading volumes. On the contrary, the influence of photovoltaic generation is of minor importance. These circumstances are illustrated in Fig. 1, where redispatch measures are correlated with generation and consumption

during the year 2018. Each data point represents a quarter hour and the color indicates the clustered intensity of redispatch demand.

Conventional power plants will be phased out over the coming years and decades. This capacity will be substituted by dispersed small-scaled biomass fired combined heat and power (CHP) systems, RES, and storage solutions (Weitemayer et al. (2015), Mengelkamp et al. (2017), Cebulla et al. (2017)). Additionally, electric vehicles (EV) might gain in importance (Flammini et al. (2019)). These

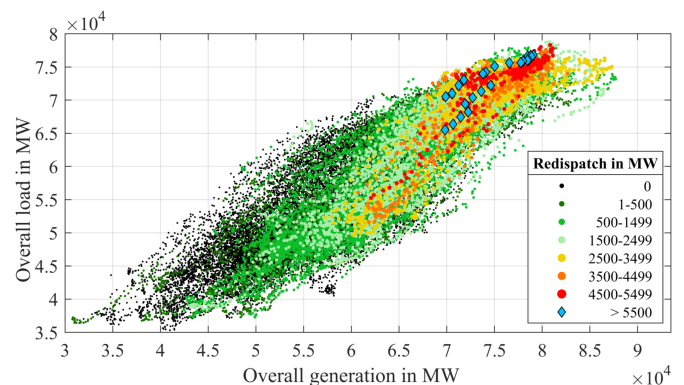


Fig. 1. Redispatch demand correlation with generation and load in Germany in the year 2018 (Netztransparenz (2019), OPSD (2019)).

unit types are characterized by low installed capacities per unit and behavior different from conventional power plants. They are usually connected to low and medium voltage grids, which may cause new congestion in distribution systems as well (Prettico et al. (2018)). Thus, new constraints and parameters have to be taken into account for determining the accessible redispatch power of dispersed flexibility:

- energy input, output, and state of charge (SOC)
- dependence on energy constraints and start-ups
- linked power schedules of units and forecast errors
- distribution system topology and operation point
- inaccessibility, as primary purpose of many units is not providing system services (e.g. loads)

Following this, we state that dispersed generation, storage, and load may be capable of providing flexible power for redispatch purpose within certain constraints. Therefore, within this paper we propose a methodology for dynamically integrating dispersed flexibility into coordinated and time-variant congestion management. Section 2 presents the fundamental idea by describing the conceptual and mathematical aspects combining methodologies of linear programming (LP) for redispatch and mixed integer linear programming (MILP) for virtual power plants (VPP) towards a time-variant integrated approach. In section 3 the developed methodology is applied in a testbed to different scenarios with CIGRE benchmark grids and flexibility coordinated in a VPP. Section 4 summarizes, compares and discusses the results of the use case studies. Finally, in section 5 recommendations are derived from this work with an outlook to further improvements and possible applications of the presented methodology, e.g. in platform-based redispatch decision making.

2. COORDINATED DYNAMIC CONGESTION MANAGEMENT WITH DISPERSED FLEXIBILITY

The concept to pool many small distributed generation, storage, and load units to a VPP is a significant achievement enabled by the advancing development of information and communication technology (ICT). The aggregator is capable of optimizing the portfolio in a flexible manner considering multiple business cases and markets, like spot markets and control reserves markets (Mengelkamp et al. (2017)). However, even large VPPs with a capacity exceeding 1000 MW are not used for redispatch yet for several reasons. These issues and how they could be resolved to give system operators access to dispersed flexibility in VPPs for redispatch are shown in Müller et al. (2019).

Besides the development of dispersed flexibility, platform approaches for supporting system operators to perform coordinated or even market-based redispatch measures are gaining in importance. With our proposed methodology we focus on leveraging synergies provided by such platforms. They allow opportunities for dynamically calculating and optimizing redispatch potentials of dispersed flexibility and VPPs in direct combination with distribution and transmission system constraints (GOPACS (2019), Mengelkamp et al. (2017)). We assume within this paper, that VPPs and other dispersed flexible units are already operating in an optimal market-based dispatch. The given scheduled power is $P_{F,z,i}$ for each unit i and discrete time

step z within the observed time period T . Hence, we do not set up solely a unit commitment problem for RES or storage systems, but we complement this category of problem by adding grid constraints for optimizing redispatch. This approach and its advantages and opportunities will be covered in the following.

2.1 Parameter-based grid constraint linearization

Congestion management requires the observance of grid constraints. TSOs perform detailed nonlinear power flow calculations, e.g. obtained by Newton-Raphson (NR) algorithm. The results indicate the grid operation point with all corresponding parameters, i.e. voltages, currents, and phase angles, as well as derived parameters like active and reactive power flows on branches. The advantage of a detailed nonlinear power flow calculation is the computational accuracy and the precise solution. Consequently, complexity and computation time increase also nonlinear with the size of the observed system (Coffrin et al. (2014)).

For coordinated congestion management, the redispatch demand and supply must be determined across different voltage levels by detailed nonlinear power flow calculations. In real time operation, these calculations must be carried out in a relatively short time with a huge amount of nodes and branches. An optimization problem using nonlinear power flow equations would be nonconvex. Hence, convergence to the global optimum and adequate computation time cannot be guaranteed. Actually, even for low numbers of variables, e.g. in small grids or with just a few dispersed flexibility units, intractability and sometimes even infeasibility is proved (Coffrin et al. (2014)). Thus, mathematical techniques which linearize around the solution of power flow equations appear promising. Basically, the categories of using direct current (DC) or alternating current (AC) power flow calculations are distinguished. An exemplary overview of different fundamental DC approaches, and DC adaptations by previous AC calculations (hot start) or Taylor series approximation is given by Yang et al. (2017), Li et al. (2018), and Stott et al. (2009). Exemplary AC approaches, e.g. fast decoupled power flow, linear programming approximation, and substitution of nonlinear terms are shown in Marley et al. (2017), Misra et al. (2018), and Coffrin et al. (2014).

As shown in Müller et al. (2018), we combine fast decoupled power flow with hot start DC power flow as a tradeoff between computational accuracy and time. Initially the operation point of the observed grid is calculated with a detailed AC power flow. By performing a voltage stability analysis, i.e. small perturbations of the grid operation point, power flow sensitivities (PFS) are derived and written into a matrix (PFSM). The PFSM S indicates how power input or output at a specific node affect specific branches. The sensitivity values $S_{n,b}$ indicate the impact of a power change ΔP_n at a node on the power flow change ΔP_b in a specific line or transformer as shown in

$$S_{n,b} = \frac{\Delta P_b}{\Delta P_n} \quad (1)$$

$$\Rightarrow \Delta P_b = S_{n,b} \cdot \Delta P_n. \quad (2)$$

In context with redispatch, we extend the methodology of calculating the PFSM by the dynamic aspect of time-

variance. Therefore, a time period T of 8 h is observed, where each time step $z \in T$ comprises 15 min. The time period duration is basically adjustable, but the chosen value of 8 h allows for exploitation of storage characteristics and is significantly decreasing forecast errors of RES and loads (Robitzky et al. (2015)). For a grid containing n_N nodes and n_B branches the impact of all power changes at nodes $\Delta P_N(z)$ on all power flow changes on branches $\Delta P_B(z)$ are computed in time dependent matrix notation as

$$\Delta P_B(z) = S(z) \cdot \Delta P_N(z) \in \mathbb{R}^{N,B}. \quad (3)$$

2.2 Time-variant LP redispatch optimization

Parameter-based linearized grid constraints are now used in a LP redispatch optimization. The entries of the PFSM are used as power transfer distribution factors, which is comparable to hot start DC power flow calculations. The redispatch optimization presented in Müller et al. (2018), which aims to minimize overall redispatch cost K_f is extended by time step z as follows

$$\begin{aligned} \min Z(z) &= \sum_{f \in F_i} K_f(z) & (4) \\ \text{s.t.} & \end{aligned}$$

$$K_f(z) \geq \max(k_{f,\text{neg}} \cdot \Delta P_f(z), k_{f,\text{pos}} \cdot \Delta P_f(z)) \quad (5)$$

$$-x \cdot C_B \leq P_B(z) + S(z) \cdot \Delta P_N(z) \leq x \cdot C_B \quad (6)$$

$$\Delta P_N(z) = \begin{bmatrix} \sum_{f \in F_1} \Delta P_f(z) \\ \dots \\ \sum_{f \in F_N} \Delta P_f(z) \end{bmatrix} \quad (7)$$

$$\sum_{f=1}^{n_F} \Delta P_f(z) = 0 \quad (8)$$

$$P_{f,\text{min}} \leq P_f(z) + \Delta P_f(z) \leq P_{f,\text{max}}. \quad (9)$$

We assume the topology of the grid, i.e. sets of nodes N , branches B , branch utilization capacities C_B as well as flexible units F_i at each node i , and variable flexibility costs $k_{f,\text{neg}}, k_{f,\text{pos}}$ to be constant during each time step. The variables are power changes of units $\Delta P_F(z)$, respectively the power changes at the nodes $\Delta P_N(z)$ with respect to given schedules $P_F(z)$.

Concluding, we are now able to optimize redispatch over a time period T by using parameter-based linearized grid constraints. Updated schedules and forecasts are processible to achieve more precise and favorable redispatch results at minimum total cost. Comparable approaches can be found in Chychykina et al. (2017), Van den Bergh et al. (2015), and Linnemann et al. (2011). Negative mutual impacts of redispatch measures, e.g. causing new congestion in the distribution grid are avoidable. Furthermore, investigations of time-variant dependencies of changing power flows and grid topologies on PFS values become feasible. The LP above proves disadvantageous for considering storage systems and controllable loads by just optimizing redispatch power, whilst redispatch energy does not play a role. Therefore, in the following we introduce an overview of optimizing a VPP with dispersed flexibility by utilizing a MILP approach to incorporate its energy constraints into redispatch optimization.

2.3 Dynamic time-variant integration of VPP redispatch potential using Mixed Integer Linear Programming

Redispatch potential of conventional power plants are computable with the above described methodology. This is mainly because redispatch potential for conventional power plants is considered as a schedule of quarter-hourly power values. There is no interdependence with the duration, so the energy amount of a redispatch measure. However, distinctive for most dispersed flexibility are their energy constraints (capacity and SOC) and further disposability limitations (Zdrilic et al. (2011)). This is especially relevant for flexible units like storage systems, electric vehicles, small-scaled CHPs, or controllable loads (Cebulla et al. (2017)). Hence, flexibility potential is defined as a set of schedules for each time step with different duration (e.g. 15 min, 1 h, ...). This ensures the feature of respecting energy constraints and satisfiability of prospective schedules within the observed time period. Corresponding supporting methodologies are described in Murray et al. (2018b), Murray et al. (2018a), and Zdrilic et al. (2011).

In Müller et al. (2019) we propose a parameter-based MILP approach computing the optimal flexibility potential of a VPP. In addition, the time-variant PFSM are integrated and the time period T is reduced from $z = 96$ time steps to $z = 32$ time steps to be compatible with the receding horizon of the grid constraint linearization and LP redispatch optimization. Nevertheless, a proper interface between the MILP VPP potential optimization and the redispatch optimization with linear grid constraints described in subsections 2.1 and 2.2 is still lacking.

Summarizing comprehensively, the potential optimization in Müller et al. (2019) is extended by time-variant PFS values, whilst the redispatch optimization of Müller et al. (2018) is extended by energy constrained flexible units. The focus is on the effect on the points of common coupling (PCC) between two grids of different voltage levels. This is most important for coordinating congestion management among system operators. Therefore, this study assigns the PFS values $s_{f,\text{PCC}}(z)$ for all nodes and PCCs special importance.

$$P_{\text{RD},f}(z) = \sum_{f=1}^{n_F} S_f(z) \cdot (P_{\text{pot},f}(z) - P_f(z)), \quad (10)$$

$$\text{with } s_{f,\text{PCC}}(z) \in S_f(z)$$

which is the sum over each difference of the optimized potential $P_{\text{pot},f}(z)$ and scheduled power $P_f(z)$ multiplied with the PFS value $S_f(z)$. At each time step an instantaneous redispatch power value for each VPP unit $P_{\text{RD},f}(z)$ is obtained which depends on both, power and energy constraints. Note that in comparison to Müller et al. (2019) the index i is changed to f . The redispatch potential for a given point in time $t \in T$, duration d , and direction $v \in \{-1; 1\}$ is given by

$$P_{\text{RD}}(t, d, v) = v \cdot \max(v \cdot P_{\text{RD},f}(z)), \quad (11)$$

This process leads to the situation that flexible units integrated in the MILP potential optimization receive variable minimal and maximal power limits, which might differ from the actual unit parameters. Hence the constraint in (9) is replaced by

$$P_{f,\text{min}}(z) \leq P_f(z) + \Delta P_f(z) \leq P_{f,\text{max}}(z). \quad (12)$$

With this adaption the time-variant VPP redispatch potentials can be integrated into the LP redispatch optimization with

- given schedules $P_f(z)$ and
- variable power limits $P_{f,\min}$ and $P_{f,\max}$ which depend on the optimized potential $P_{\text{pot},f}(z)$.

Finally, the dynamically aggregated redispatch potential of conventional power plants and dispersed flexibility in a VPP within an observed grid area is calculated.

3. TESTBED FOR BENCHMARK SCENARIOS

To validate the proposed methodology and reveal functionality and results, a testbed for benchmark scenarios is designed. The simulation time period T of the receding horizon is set to 8 h, which comprises $z \in t$ with $t = 32$ time steps of 15 min. This ensures accurate generation and load forecasts and superior utilization of energy constrained units. Moreover, a study of historical redispatch measures in Germany from 2013 to 2019 based on OPSD (2019), and Netztransparenz (2019) reveals redispatch duration between 15 min and 5 h as most common.

We deploy the methodology in a vertically integrated benchmark system, as already used in Müller et al. (2018). It covers and combines different medium voltage (MV) 20 kV, high voltage (HV) 110 kV and extra-high voltage (EHV) 220/380 kV systems. The MV level of 20 kV is emphasized, because most dispersed flexibility is expected to be connected to MV distribution systems. Grid element types, conventional generation, RES, load, and grid topology are mainly based on CIGRE benchmark grids and open source projects, like SimBench (2019) or OPSD (2019). The design allows options for changes in grid topology, e.g. by switching string setups to a ring setup or adding transformers for higher interconnection and meshing. By this, exploration of dynamic time-variant effects on PFSM, congestion, and redispatch potentials becomes feasible. For the sake of simplicity, topology changes are not done during one simulation period. Nevertheless, for further simulations of the continuous receding horizon divergent grid topologies are conceivable.

Different scenarios for the development of dispersed flexibility are deployed. Within this study, the scenarios for 2018 and 2030 are selected, which are based on a meta study carried out in Müller et al. (2018). Conventional power plants and grid elements are supposed to remain constant until 2030. Hence, we want to show the different results with changes in the amount and distribution of dispersed flexibility, as well as the results of switching given grid topologies to ensure comparability. We assume new storage systems, controllable loads, and small-scaled CHP plants which will be integrated into a VPP and are connected to the MV grid. Therefore, these flexibilities will be optimized with the methodology described in section 2.3. Increasing wind and photovoltaic systems as main drivers of RES development are difficult to control in terms of aiming at flexible redispatch potential purposes. These units will remain in the regular redispatch optimization as curtailment options with high penalization cost. The composition of the considered and optimized VPP, as shown in Table 1, is also based on these assumptions.

Table 1. Considered unit types for the VPP in the scenarios for 2018 and 2030

VPP Technology	2018		2030	
	kW	amount	kW	amount
Biogas CHP plants	1080	1	2580	2
Controllable loads	0	0	2000	2
Storage systems	651	3	18789	17

4. SCENARIOS RESULTS AND DISCUSSION

In the following, we will present the results of each partial methodology and the combined approach with major significance for coordinated use of dispersed flexibility in time-variant redispatch potential maximization. At first the linearization methodology delivers precise results with a low linearization error as shown in Müller et al. (2018). During the observed time period, generation and load units dispatch changes intensely, so likewise power flows and branch loadings do. In Fig. 2 the dynamically changing branch loadings are depicted for a typical scenario in 2018 on the left side and for 2030 on the right side. An open topology (switches open, no additional transformer) is shown at the top and a closed topology (all switches closed, additional transformer active) at the bottom. The vertical columns 1 to 40 represent the lines from EHV to MV grid in descending direction. The transformers are represented by the vertical columns 41 to 50. In the scenario of 2018 we do not realize congestion in both of the topologies, as no branch loading exceeds 92%. Quite contrary to the scenario of 2030, where congestion occur by loadings over 100% up to around 129% for several lines and transformers. Reasoned by missing congestion occurrence in the 2018 scenario, we focus on the 2030 scenario results in the following, where also shifts of congestion issues to the MV grid are recognized.

Consecutively, the assumption could be made that volatile power flows and loadings cause also deviation of the PFS values after linearization. But, after changing the topology within the observed grid area, we infer the topology condition more important for the determination of PFSM than actual power flows. Fig. 3 shows the PFS values of each node of the grid area towards the transformer at the

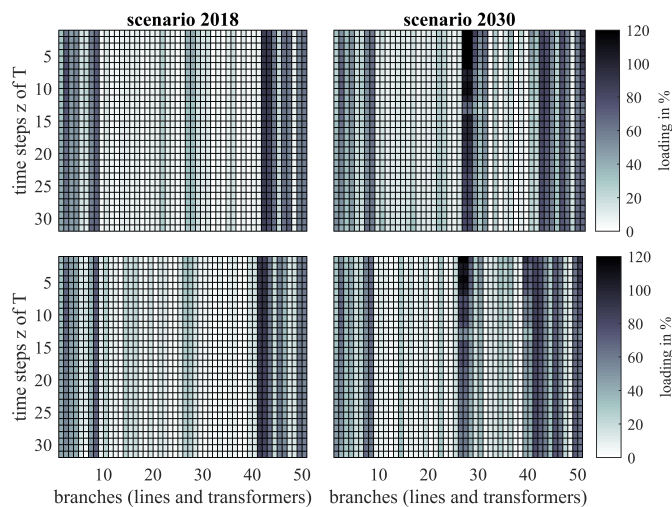


Fig. 2. All branch loadings at each time step for 2018 (left) and 2030 (right) in the open topology (top) and the closed topology (bottom)

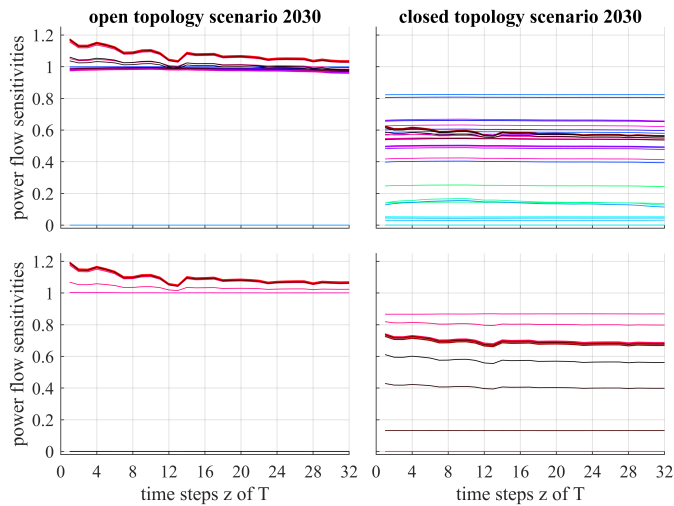


Fig. 3. PFS values of each observed node towards the HV-EHV PCC (top) and the MV-HV PCC (bottom)

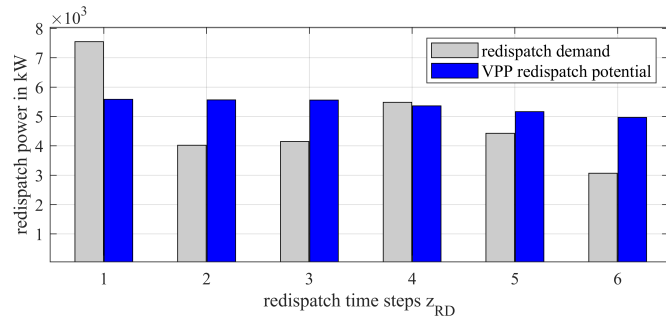


Fig. 4. The overall redispatch demand regarding the congested branch compared to the maximum redispatch potential offered by the VPP

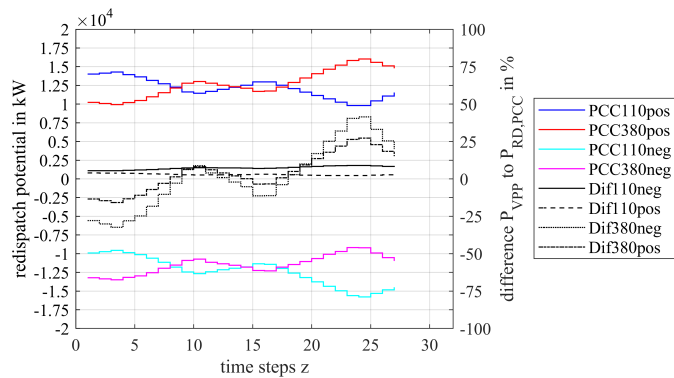


Fig. 5. Dynamically aggregated redispatch potential of the VPP at the PCC. Black lines indicate the difference between unit power and actual power efficacy at PCC

PCC between the HV and EHV grid (PCC380) at each time step $z \in T$. Green and turquoise plots represent EHV nodes, blue HV nodes, and red to black MV nodes. The higher meshing of a closed topology lowers the average PFS values significantly because power flows have more options to split up. The mean difference between the absolute PFS values of an open topology and a closed topology is 0.28. Within an open topology the nodes in the EHV grid do not have any influence on the PCC380 because the slack node (respectively external systems) where overall power is balanced is assumed in the EHV

grid. Closing the topology by adding a second transformer between HV and EHV grid leads to slight influences, as shown by the turquoise and green colored plots in the interval of $0 \leq S \leq 0.3$ in the top right diagram of Fig. 3. The same effects occur at the PCC of MV and HV grid (PCC110) in the bottom diagrams of Fig. 3.

The top right diagram of Fig. 2 reveals for the year 2030 scenario an intense redispatch demand for the branches connecting the MV and HV grids for the first six time steps in both topology configurations. The MV grid is load dominated and the power flows are in top-down direction. Therefore, we are especially interested in positive redispatch potential, so increasing generation or decreasing load. By optimizing redispatch with the LP methodology for every time step neglecting the energy constraints, we obtain a redispatch demand result in the interval z_{RD} shown in the grey bars of Fig. 4.

The calculated redispatch measures are probably not feasible for the considered VPP. Therefore, the methodology of energy-constrained VPP redispatch optimization by MILP approach is used. In Fig. 5 the redispatch potential of the VPP towards the PCC110 and the PCC380 is shown for the duration of z_{RD} . Hence, this is the potential the VPP could offer the TSO, respectively the HV-DSO. The black lines indicate the difference between the actual unit power and the impact of the power flows at the corresponding PCC. We find that the PCC380 shows significant higher and more volatile differences than the PCC110. This is caused by power flow direction changes via the PCC380, so in times where the potential at the PCC380 is substantially lower than the actual unit power, the power flows are bottom up from HV to EHV grid. Towards the end of the time period the potential towards the PCC110 raises due to less importance of energy constraints. This effect is mitigated by using the receding horizon, where every quarter hour new calculations are carried out, whereby the potential gets updated. The absolute values should not be overinterpreted because they are strongly depending on flexibility assumptions (like initial SOC), grid topology, and the location and amount of congested branches.

By integrating the flexible redispatch potential of VPPs into the redispatch optimization through flexible time-variant power limits, we obtain a meaningful result for the given preconditions and the coordinated optimization methodology is proved. The resulting VPP redispatch potential in comparison to the overall redispatch demand regarding the congested branch is depicted by the blue bars of Fig. 4. Hence, in the given scenario the redispatch power demand could be fulfilled in $z = 4$ of $z_{RD} = 6$ time steps and up to 92.75 % of the redispatch energy demand could be met with dispersed flexibility organized in a VPP.

5. CONCLUSION AND OUTLOOK

The presented methodology allows for elaborations with different voltage levels, grid model topologies, and especially a broad variety of dispersed flexibility, whether organized in VPPs or not. The integrated and coordinated methodology combines dynamically time-variant linearized grid constraints, dispersed flexibility and congestion management optimization. It provides meaningful results under the given circumstances and assumptions.

Several purposes can be complied with, e.g. platform-based congestion management for enhancing obligatory redispatch or for the creation and operation of flexibility and redispatch markets.

Nevertheless, the methodology is to be further improved. We aim at taking all relevant flexibility technologies into account, e.g. all kinds of RES or different controllable loads (industry, retail, households, mobility) and deploy a platform oriented approach. For future research the goal is to enlarge the VPP with respect to the amount and types of units and test more than one VPP in different grids whilst preserving computational calculability. Thus, we expect to face new challenges in terms of complexity and computation performance. Besides VPP design, the strong influence of the grid topology on PFSM and redispatch potentials is of special interest and must be investigated further. To this end, the methodology will be tested in a broad variety of grids and topologies to obtain hints which topology and grid parameters are influencing PFS values and dispersed flexibility potentials the most.

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