Demand Response Control in Low Voltage Grids for Technical and Commercial Aggregation Services

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***Abstract*—The electrification of sectors such as heating and transportation represents a challenge as well as an opportunity for distribution system operators. On the one hand, they are committed to accommodate large numbers of highly rated loads in networks for which it was not designed. On the other hand, some of those represent a source of flexibility that can be used to satisfy different technical and commercial purposes. This paper introduces an upgraded hierarchical structure that aims to serve as a platform for activating and controlling the demand response in low voltage (LV) networks. In this way, a system operator playing a role of an aggregator not only could trade flexible demand in the power markets, but also materialize its energy agreements while ensuring the local network security and reliability. To verify the effectiveness of this extended method, a Danish LV network is considered. The results show that it is possible to fulfill energy commitments in energy markets such as the regulation power market while respecting the proper network operation. However, the activation of the flexibility offered might be limited depending on the network characteristics and the season of the year.**

***Index Terms*—Demand response, heat pump (HP), hierarchical control, low voltage (LV) networks, plug-in electric vehicles (PEVs).**

I. INTRODUCTION

OVER THE years, the wind and photovoltaic (PV) power capacity installed in Denmark has steadily increased due its ambitious sustainable energy policies. These installations have further gained acceleration as a consequence of the latest energy agreement of March 2012 [1]. This scenario calls for a paradigm shift in power system operation. The development of a "smart energy system" concept is a promising solution which relies on the idea of closely interacting the power, heating, and transportation systems to aid the balancing of the electricity network [2]. However, its materialization requires an extensive electrification of the two additional systems which implies that the power system load will significantly grow in the future. This is especially relevant in low voltage (LV) distribution grids, since heat pumps (HPs) and plug-in electric vehicles (PEVs) are the major expected loads [3]. For a distribution system operator (DSO), this represents a challenge as well as an opportunity. On the one hand, the DSO is committed to accommodate large numbers of these loads in networks for which it was not designed. On the other hand, this scenario introduces demand response opportunities for technical and economic operation of distribution networks.

The benefits of demand response in LV grids are recently demonstrated by many researchers. By scheduling domestic loads, Jargstorf *et al.* [4] optimized the operating temperature of the secondary transformer (ST) reducing its aging up to 75%. Kadurek *et al.* [5] and Efkarpidis *et al.* [6] employed an on-load tap changer at the ST to adjust the LV network demand and consequently maintain the voltage within the stated limits and reduce thermal constraints. In [7], by making HPs react to local price discrimination, the overloading of the power infrastructure gets significantly reduced. Marra *et al.* [8], [9] exploited the electric vehicle (EV) storage capabilities to effectively control the voltage of the LV network in the presence of high penetration of PV power. By optimally controlling the charging rate of PEVs, the residential networks are able to accommodate many of those with little or no need for upgrading the existing infrastructure [10]. Some other studies have focused in modeling the demand response aggregation from a higher system perspective with various purposes. In [11] and [12], the response from large numbers of controlled thermostatic loads is employed for delivering power regulation and load following services. Similarly, populations of HPs and PEVs are controlled in [13] in order to mitigate the variability of wind energy production. Nevertheless, those studies assume full capability of distribution systems to distribute the power requested by the controllable loads without inducing any congestion. This is not very realistic especially considering that the current infrastructure is not designed to accommodate those in large numbers. Wang *et al.* [14] presented a hierarchical approach to utilize the response of flexible loads to provide spinning reserve services. Since this paper is approached from an aggregated perspective, it is not precisely defining how its practical implementation is carried out and how the materialization of the set points at the single device level is done. Through similar concept in [15], the charging of PEVs is optimized in order to ensure the local network security. In this case, the analysis is seen from an steady-state perceptive neglecting the system dynamics given within the time steps.

The advantages of demand response are also relevant from an economic and/or commercial perspective for different stakeholders involved. Regarding the consumers,

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Molitor *et al.* [16] and Pfaffen *et al.* [17] found that non-negligible revenues could be achievable by making consumer in possession of thermostatic loads participate in time-varying price tariffs, tertiary control provision, or intraday transactions. In relation to the DSOs, Nykamp *et al.* [18] stated that an optimal integration and control of these loads could reduce the grid reinforcement costs by 10%. Even though in [19], it was found that the economical benefits per household basis might be relatively low when residential demand response participates in the Dutch electricity markets, and it also states that these might be considerable for the business case of an aggregator. Finally, Omagari *et al.* [20] demonstrated how the introduction of demand response in the electricity markets may result in market clearing price reductions by shifting electricity demand from peak to off-peak periods.

As it is reflected above, notable research has focused either in the technical or in the economical aspects of the demand response, but most of the time this is approached individually. Although, the combination of both aspects is less commonly tackled, it shows a big potential in the design of future demand response strategies. For example, through the corresponding market framework, a DSO playing the role of an aggregator (DSO-A) could design a strategy so that it exploits its demand response resources for decongesting parts of the network during peak demand periods by shifting the flexible demand to low price off-peak hours. On the other hand, it should also be stated that local network safety and reliability should be prioritized over any energy commitment.

Taking that into consideration, this paper aims to develop a demand response control mechanism to successfully merge the technical and commercial aspects of the LV grid operation. Therefore, there are few aspects that are carefully addressed: 1) be in accordance with the European Standard EN 50160; 2) dismiss any end-consumer discrimination by treating them equally; and 3) satisfy any undertaken commercial agreements. Hence, this paper introduces an upgraded version of the hierarchical structure proposed in [22] aiming to serve the DSO-A for activating and controlling the demand response in LV networks according to its interest. The novelty of this paper relies on a decentralized platform which allows DSO-A to not only trade flexible demand in different market frameworks but also to materialize the undertaken commercial agreements while ensuring that the operation of the local LV system targeted is maintained within the stipulated limits. The competence of being able to do so depends on having a good estimation on the response of the flexible loads. Attending to the findings of Marra *et al.* [8], the system is designed to act over the active power consumption of HP and PEV loads for targeting any of the purposes mentioned before. It is worth to clarify that this paper is only limited to the demand side and therefore only loads are considered. Under the presence of distributed generation, the performance of such a platform should not be affected much as the only factor that should be considered is that controllers in each case should be retuned appropriately. The main contributions of this paper are as follows.

1) New control features to make the HP systems respond to demand aggregation needs for electricity trading purposes. This is based on dynamic modification of its control settings for adapting its operation to the given circumstances.
2) A simple method to determine the power demand flexibility of the LV network. This refers to its up regulation (UR) and down regulation capacity which is defined by flexible consumption that is able to activate within the hour ahead.
3) A demonstration of the advantages of implementing the upgraded hierarchical structure is applied on an LV grid test case currently operative in Denmark under relevant scenarios.

The rest of this paper is arranged as follows. Section II summarizes the models and appliance controls designed in [22] emphasizing in the new control features. Section III summarizes the proposed hierarchical structure and describes the flexibility estimation and the market participation of the DSO-A. Section IV discusses the LV test system and the case studies used for the verification. In Section V, the obtained results are accompanied by its correspondent discussion. Finally, in Section VI a short summary and the conclusion is provided.

II. Flexible Loads: Control Upgrades

Since [22] represents a base reference, this section summarizes the models developed in it highlighting the new upgrades. DIgSILENT PowerFactory is the simulation tool utilized.

A. HP System

The HP system model is composed of an air-to-water HP and a hot water storage tank (HWST). The HP is represented by a polynomial expression of the coefficient of performance (COP) as a function of the atmospheric temperature (T_{atm}). The energy stored in the HWST (E_s), in the form of hot water, is calculated based on an energy balance. Extensive description of its mathematical representation is available in [22].

Since the HP is classified as a thermostatic load, it is normally controlled based on a hysteresis control. When E_s drops below the cutoff band ($\underline{E}_c$), the HP turns ON to recoup the thermal energy used or lost. It will remain ON up to the point when the E_s reaches the upper band ($\bar{E}_c$). This stands for the passive way of controlling such kind of device. As it was illustrated in the work cited above, the performance of the air to water technology is very dependent of the sink and source conditions. Under low atmospheric temperatures and high thermal demand, the unit might need to operate very frequently, sometimes even constantly, to maintain the state of energy (SOE) in the HWST within the defined energy levels. In extreme situations, where the unit is not capable to provide what is requested by itself an additional source of heat is required which is normally done via an electric resistor. Those sort of situations might lead to a challenging scenario for the DSO, especially in areas with large concentration of HPs where the substantial increase in power demand could constrain the LV grid as a consequence. Since the ratting of unit selected is sufficient to provide the thermal requirements considered this, aspects are not specifically taken into account in this paper.

Nevertheless, their flexible nature allows to control them in an active manner, i.e., to avoid bottlenecks in the distribution system or participate in demand aggregation campaigns of electricity trading. This fact demands new innovative techniques for the control of these loads. Based on that, the HP control designed in [22] has been provided with an extra operation mode. This mode named "demand aggregation mode" (DAM) is appended to the already existing voltage emergency mode (VEM). The criteria employed for switching from mode to mode is

$$\begin{aligned} &V_{\min} \geq V_r \;\;\&\;\; k_v > k_l \;\;\&\;\; \Delta P = 0 \rightarrow \text{NOM} \\ &V_{\min} \geq V_r \;\;\&\;\; k_v > k_l \;\;\&\;\; \Delta P \neq 0 \rightarrow \text{DAM} \\ &V_{\min} < V_r \rightarrow \text{VEM} \end{aligned} \tag{1}$$

where $V_{\min}$ is the minimum voltage of operation, in per unit (p.u.), V_r is its predefined limit, k_v and k_l are internal variables of the HP controller, and ΔP is a power deficiency signal in kW. ΔP represents the difference between the power measured at the ST level and demand rate committed according to the power market. This is calculated by the main supervisory feature in the LV network and is delivered to the HP systems via the corresponding subsystem (SS)—Sections III-B and III-C.

1) Voltage Emergency Mode: The VEM was designed to allow the HP systems adapting their operation to voltage violations happening in the LV network. When a severe violation occurs the $\underline{E}_c$ is allowed to drop to a 20% lower energy level than normal mode, making the HP remaining OFF for a long time. Considering that the load activation is delayed the aggravation of this technical constraint is avoided.

Since, the LV grid condition is different when a voltage violation occurs and when it is cleared the control projects a pre and a postactuation zone. The decision of which violation represents a potential risk to make the HP react is decided in the preactuation zone. The postactuation instead is a transition zone where after the violation is cleared the HP has to smoothly leave the VEM to enter in the NOM again.

2) Demand Aggregation Mode: The aim of this mode is to provide the HP with an ability to respond to the demand aggregation needs required during an energy commitment. This should be realized causing minimum discomfort for the user. As for the VEM, the HP operation is accommodated by altering the $\underline{E}_c$ and $\bar{E}_c$ bands based on the logic below

$$\begin{aligned} -\alpha \geq \Delta P \leq \alpha \;\rightarrow\;\; \underline{E}_c = \underline{E}_c^{\mathrm{no}}, \;\; \bar{E}_c = \bar{E}_c^{\mathrm{no}} \\ -\alpha < \Delta P > \alpha \;\rightarrow\;\; \underline{E}_c = \underline{E}_c^{\mathrm{da}}, \;\; \bar{E}_c = \bar{E}_c^{\mathrm{da}} \end{aligned} \tag{2}$$

where $\pm\alpha$ is the bandwidth defined to make the HP uninfluenced by ΔP, $\underline{E}_c^{\mathrm{no}}$ and $\bar{E}_c^{\mathrm{no}}$ are the maximum and minimum energy bands, in p.u., when operating in NOM, and $\underline{E}_c^{\mathrm{da}}$ and $\bar{E}_c^{\mathrm{da}}$ are the same as for the DAM. The ability of HPs to precisely regulate its demand is practically nonexisting. Either it consumes at the rated power while it is ON or it turns OFF. Therefore, they normally find difficulties to track precisely any external request without compromising the user comfort. So, to avoid ineffective adjustments of $\underline{E}_c^{\mathrm{da}}$ and $\bar{E}_c^{\mathrm{da}}$, due to the ΔP dynamics a bandwidth $\pm\alpha$ is defined. While ΔP stands between $\pm\alpha$, the $\underline{E}_c^{\mathrm{da}}$ and $\bar{E}_c^{\mathrm{da}}$ remain unaffected, but as soon

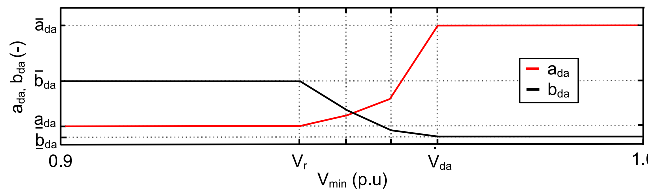

Fig. 1. Design of a_{da} and b_{da} integration variables.

as ΔP steps out the $\underline{E}_c^{\mathrm{da}}$ limits are adjusted according to

$$\underline{E}_c^{\mathrm{da}} = \int a_{\mathrm{da}} \cdot dt; \quad \underline{E}_c^{\mathrm{no}} \leq \underline{E}_c^{\mathrm{da}} \leq \left(\underline{E}_c^{\mathrm{da}}\right)_{\max} \tag{3}$$

$$\bar{E}_c^{\mathrm{da}} = \int b_{\mathrm{da}} \cdot dt; \quad \left(\bar{E}_c^{\mathrm{da}}\right)_{\min} \leq \bar{E}_c^{\mathrm{da}} \leq \bar{E}_c^{\mathrm{no}} \tag{4}$$

where a_{da} and b_{da} are the integration variables determining the adjustment of $\underline{E}_c^{\mathrm{da}}$ and $\bar{E}_c^{\mathrm{da}}$. $(\underline{E}_c^{\mathrm{da}})_{\max}$ is the maximum saturation point for $\underline{E}_c^{\mathrm{da}}$, and $(\bar{E}_c^{\mathrm{da}})_{\min}$ is the minimum saturation point for $\bar{E}_c^{\mathrm{da}}$. Since the voltage sensibility is different across the LV network, the impact produced by these loads depends significantly on their location. To reduce this impact during an demand aggregation need, the loads should respond differently according to their location. Therefore, if the LV grid demand is required to get increased—down regulation from a generator perspective—the HP systems placed in locations which are less sensitive to voltage variations (strong) should adjust their $\underline{E}_c^{\mathrm{da}}$ more evidently than those located in highly sensitive (weak) points, to anticipate their activation. However, if the LV grid demand needs to be decreased—UR from a generator perspective—those located in weaker locations should adjust their $\bar{E}_c^{\mathrm{da}}$ more evidently than those located in stronger points, to benefit from their disconnection. Since $V_{\min}$ represents literally the electrical strength of an area, it is used to determine the dynamical alteration of $\underline{E}_c^{\mathrm{da}}$ and $\bar{E}_c^{\mathrm{da}}$. As it is mentioned before, it is important that $\underline{E}_c^{\mathrm{da}}$ and $\bar{E}_c^{\mathrm{da}}$ are independently altered, so as the logic for representing a_{da} and b_{da}. The variable a_{da} is supported by

$$\begin{aligned} V_{\min} < V_r \;&\rightarrow\; a_{\mathrm{da}} = \underline{a}_{\mathrm{da}} \\ V_r \leq V_{\min} < \dot{V}_{\mathrm{da}} \;&\rightarrow\; a_{\mathrm{da}} = \bar{a}_{\mathrm{da}} \cdot \frac{\bar{a}_{\mathrm{da}}^{\left(\frac{V_{\min}}{\dot{V}_{\mathrm{da}}-V_r} - \frac{\dot{V}_{\mathrm{da}}}{\dot{V}_{\mathrm{da}}-V_r}\right)}}{\underline{a}_{\mathrm{da}}} \\ V_{\min} \geq V_r \;&\rightarrow\; a_{\mathrm{da}} = \bar{a}_{\mathrm{da}} \end{aligned} \tag{5}$$

where $\underline{a}_{\mathrm{da}}$ and $\bar{a}_{\mathrm{da}}$ are the minimum and maximum saturation points for a_{da}. The variable b_{da} is instead supported by

$$\begin{aligned} V_{\min} < V_r \;&\rightarrow\; b_{\mathrm{da}} = \underline{b}_{\mathrm{da}} \\ V_r \leq V_{\min} < \dot{V}_{\mathrm{da}} \;&\rightarrow\; b_{\mathrm{da}} = \underline{b}_{\mathrm{da}} \cdot \frac{\underline{b}_{\mathrm{da}}^{\left(\frac{V_{\min}}{\dot{V}_{\mathrm{da}}-V_r} - \frac{\dot{V}_{\mathrm{da}}}{\dot{V}_{\mathrm{da}}-V_r}\right)}}{\bar{b}_{\mathrm{da}}} \\ V_{\min} \geq V_r \;&\rightarrow\; b_{\mathrm{da}} = \underline{b}_{\mathrm{da}} \end{aligned} \tag{6}$$

where $\underline{b}_{\mathrm{da}}$ and $\bar{b}_{\mathrm{da}}$ are the minimum and maximum saturation point for b_{da} and $\dot{V}_{\mathrm{da}}$ is voltage limit making a_{da} saturate at $\bar{a}_{\mathrm{da}}$ and b_{da} saturate at $\underline{b}_{\mathrm{da}}$. To better understand (5) and (6), Fig. 1 depicts its physical representation. The tuning of the DAM settings implies a tradeoff. A conservative adjustment of its parameters leads the HP systems to the impossibility

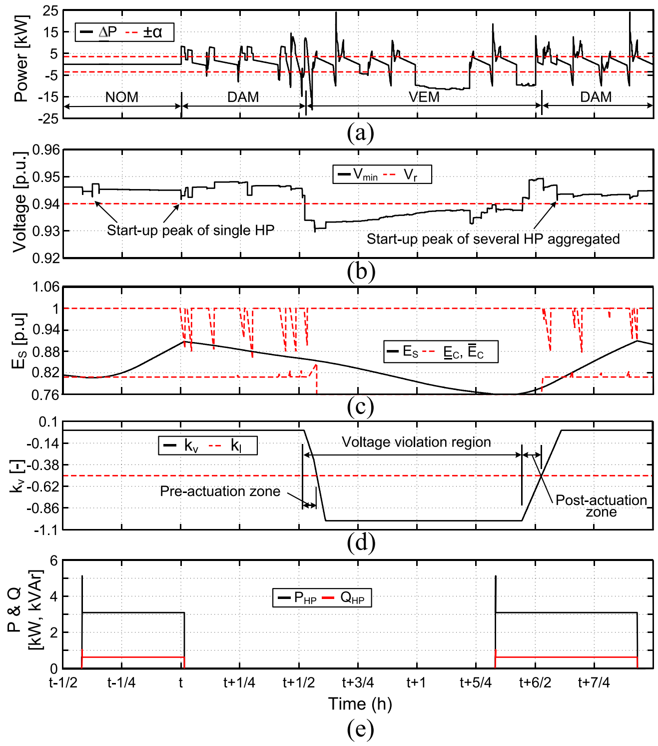

Fig. 2. HP control modes. (a) ΔP. (b) $V_{\min}$ and V_r. (c) E_S, $\underline{E}_c$, and $\bar{E}_c$. (d) k_v and k_l variables. (e) P_{HP} and Q_{HP} patterns.

of tracking ΔP closely. As a consequence of this aggressive adjustment, the HP unit turns ON and OFF frequently decreasing efficiency of the HWST supply.

3) Verification of HP Control Modes: To do so, the model of an HP with a 500l HWST employed in [22] is utilized. Fig. 2 illustrates an example of its operation during two and a half hours. Fig. 2(a) shows the ΔP signal received by the HP system to encourage its response. Fig. 2(b) shows the $V_{\min}$ profile during this period. According to the EN 50160, the voltage in the medium voltage (MV) and LV systems should always be within ±10%. Based on practical experiences from DSOs, a more conservative value is selected for this case, ±6%.

During the first half hour, $V_{\min} > V_r$ and $\Delta P = 0$; therefore, the HP system runs in NOM. In this context, $\underline{E}_c$ and $\bar{E}_c$ conserve the original settings. At hour t, ΔP becomes distinct to 0. Therefore, the HP controller switches to DAM to respond to the demand aggregation request. Notice, how ΔP has a positive sign in the first place. This means that the power consumption measured at the ST level is higher than the one defined by the energy commitment. So, the need for decreasing the aggregated demand of the LV grid makes the HP controller adjusting $\bar{E}_c$ to trigger the disconnection of the appliance in advance [see Fig. 2(c)]. Furthermore, the HP system represented in this example appears to be located in a weak part of the LV network. This is well distinguished because the DAM is more incisive in the adjustment of $\bar{E}_c$, for its early disconnection, than $\underline{E}_c$. Under the DAM, the accommodation of $\underline{E}_c^{\mathrm{da}}$ and $\bar{E}_c^{\mathrm{da}}$, and in result $\underline{E}_c$ and $\bar{E}_c$, is made based on the parameterization as shown in Table I.

In this paper, the DAM is designed to make the $\bar{E}_c$ reach $(\bar{E}_c^{\mathrm{da}})_{\min}$, in about 1.1 min at a $V_{\min} = 0.94$ p.u. and in about 5 min when $V_{\min} = 0.97$ p.u. The $\underline{E}_c$ instead should achieve $(\underline{E}_c^{\mathrm{da}})_{\max}$ in about 6.5 min at a $V_{\min} = 0.94$ p.u. and in 24 s when $V_{\min} = 0.97$ p.u. Even though the tuning selected seems to be a bit conservative, it allows the HP systems responding to ΔP without compromising the correct performance of the device. Past $t + 1/2$ h, even though ΔP remains still active, the HP controller switches to VEM due to a voltage violation. The parameterization selected for VEM coincides with the one utilized in [22]. Fig. 2(d) represents the evolution of the internal variable k_v, which according to the severity of the violation determines the specific moment to shift $\underline{E}_c$. The broadening of $\underline{E}_c$ allows E_S to drop to lower energy levels delaying its activation and in consequence avoiding the aggravation of this constraint. Past $2t + 1/2$ h, the voltage gets restored and since ΔP is still active, the HP controller switches from the VEM back to the DAM. Finally, as Fig. 2(e) depicts, the HP consumption of active and reactive power (P_{HP}, Q_{HP}) is successfully adapted to fulfill both technical and commercial requirements.

TABLE I
DAM TUNING

Parameter	Value	Parameter	Value
$\pm\alpha$	3.5	$(\underline{E}_c^{da})_{max}$	0.8875
$\dot{V}_{da}$	0.97	$(\bar{E}_c^{da})_{min}$	0.9125
$\underline{a}_{da}$	0.0015	$\underline{b}_{da}$	0.002
$\bar{a}_{da}$	0.025	$\bar{b}_{da}$	0.0088

B. PEV System

The model developed in [22] is constituted of the battery storage, the domestic charging station, and the driving pattern (DP) of the specific user. The battery is represented with a Thevenin-based model, which defines its state of charge (SOC) according to the charging and discharging. The domestic charging station was procured with the ability for regulating the charging capacity, between 0 and its rated power ($P_{\mathrm{PEV}}^{\mathrm{rt}}$). The power drawn by the device (P_{PEV}) was calculated as

$$P_{\mathrm{PEV}} = \eta_c \cdot \int S_{\mathrm{ch}} \cdot dt; \quad 0 \leq P_{\mathrm{PEV}} \leq P_{\mathrm{PEV}}^{\mathrm{rt}} \tag{7}$$

where η_c is the charger efficiency. S_{ch} represents the charging capability of an specific PEV and is defined by its SS—Section III-B. The user DP was modeled as the home departure and arrival times and the distance driven in a day. To preserve the battery life, the SOC was maintained within 0.2–0.9 p.u.

III. HIERARCHICAL CONTROL OF DEMAND RESPONSE

In this section, the hierarchical structure proposed in [22] for commanding the demand response in LV grids is summarized. As it is stated earlier that concept should be framed in a future scenario, like the one described in projects such as iPower [21], where smart meters and local grid controllers (CPUs) become an essential part of the power system operation. Furthermore, the new features implemented together with the flexibility estimation and the market participation of the DSO-A are described. With its implementation, a DSO-A would be able to

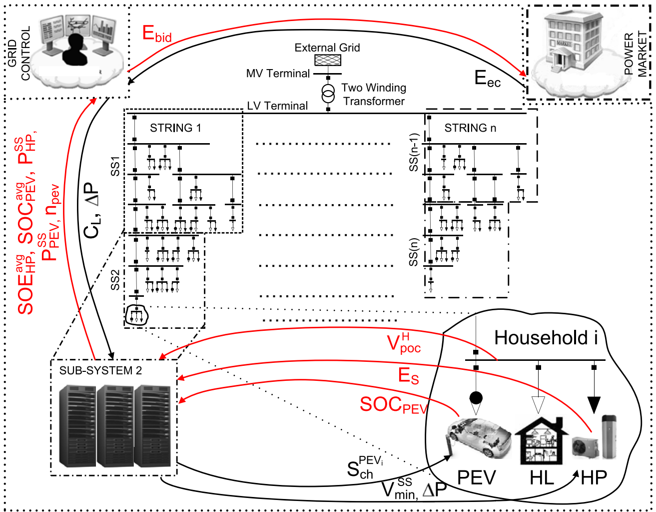

Fig. 3. Hierarchical control of the demand response in the LV Grid.

develop technical and commercial services independently or in combination. On the one hand, this should enhance the LV grid utilization respecting the user comfort and power requirements. On the other hand, it should serve as a mechanism to materialize the energy commitment established by the considered market platform. When the LV network safety gets jeopardized, it needs to be clarified that the technical reliability should be prioritized over satisfaying any commercial agreement even if it implies an economical sanction.

Fig. 3 illustrates the hierarchical structure proposed to control the flexible demand of the LV grid. This is composed of three layers: 1) the unit control; 2) the subsystem control; and 3) the distributed grid control (DGC). The LV network is divided into different SSs. The DGC which stands for the main supervisor block has a direct communication with all the SSs for having a good overview of the LV grid condition. Furthermore, it monitors the average energy stored in the LV system and estimates its flexibility, in terms of UR and down regulation, within the next hours. Based on this, it is responsible for deciding the energy bids to be sent to the power market. The SSs instead are responsible for monitoring a group of households and in case they have HPs and/or PEVs to be operated. The loads report constantly their energy status to the SS they belong to. Since the different layers are extensively described in [22], only a short introduction is presented below.

A. Unit Control

It refers to the control embedded in the flexible appliance which intends to keep the stored energy within some limits.

B. Subsystem Control

Located at the distribution feeder level, it monitors a number of households (n_h) and according to its needs acts over the HP and PEV under its domain. Its obligations are as follows.

1) *Data Collection and Processing:* Voltage at the POC of each household (V^H_{poc}), the SOC of each plugged-in vehicle (SOC_{PEV}), and the E_S on each HP system.
2) Calculation of the minimum voltage in the SS ($V^{\text{SS}}_{\text{min}}$).
3) *Prioritize Plugged-in PEVs—Calculation and Dispatch of S_{ch}:* The S_{ch} received by a specific PEV ($S^{\text{PEV}i}_{\text{ch}}$) is

$$S^{\text{PEV}_i}_{\text{ch}} = C_L \cdot A_p(i) \cdot x + (x-1); \qquad x \in [0,1];\; i = 1\ldots n_{\text{pev}} \quad (8)$$

where n_{pev} is the number of available PEVs in the SS, x the binary variable defining any voltage violation in the SS, and A_p the vector holding the different charging amplitudes. PEVs with lower SOC are normally prioritized so they are assigned with a higher $A_p(i)$ value which makes their charging rate higher. C_L is a limitation variable set by the DGC to influence their charging process—Section III-C.
4) Delivery of n_{pev} to the DGC.
5) *Communication of ΔP to the HPs:* ΔP is used by the DGC to encourage a response from HPs when an energy commitment has to be materialized. This is done by delivering ΔP to the HPs in the LV grid via the different SSs.
6) Calculation and delivery to DGC, the average SOE ($\text{SOE}^{\text{avg}}_{\text{HP}}$), average SOC ($\text{SOC}^{\text{avg}}_{\text{PEV}}$), and total power demand from HPs ($P^{\text{SS}}_{\text{HP}}$) and PEVs ($P^{\text{SS}}_{\text{PEV}}$) in the SS.

C. Distributed Grid Control

Placed at the ST level, the DGC represents the central component of the hierarchical structure. It is responsible for monitoring the different SS in the LV grid. Depending on the LV grid condition and its market strategy, it influences the HP and PEV loads operation via the C_L and ΔP signals delivered to each SS. Two of the tasks it focuses are as follows.

1) Equalization of SOE Between Different SSs: The aim is to achieve an equilibrium on the performance of the different SSs and a more even behavior of LV network to avoid local congestions during critical moments of the day. First, based on the $\text{SOE}^{\text{avg}}_{\text{HP}}$ and $\text{SOE}^{\text{avg}}_{\text{PEV}}$, the average SOE in each SS ($\text{SOE}_{\text{SS}\#i}$) is calculated. Then, in practice, the DGC divides the total power transfer capability of the LV grid among the n SSs (n_{ss}) according to their $\text{SOE}_{\text{SS}\#i}$ and the network condition. The logic describing the way this is done is available in [22]. Nevertheless, as (14) illustrates it, this has been upgraded in order to accommodate a new capability detailed in the next section. So, when the maximum power transfer capability of the LV grid is reached, i.e., operating points close to the undervoltage limit, the only way to increase the power consumption capability of the SS with lowest SOE is by reducing the capability from the rest of them. In this sense, since controllability of the PEVs is more precise this task is carried out by limiting, via the C_L variable, the charging rate of the PEVs plugged-in those SSs.

2) Flexibility Estimation and Participation in Regulation Market: In the Scandinavian context, most of the electricity is traded in NordPool Spot via a day-head (Elspot) and a intraday (Elbas) market [23]. To adjust the imbalances originated after scheduling in those markets, the transmission system operators (TSOs) use the regulation power market (RPM) and the reserve capacity market (RCM). The operation requirements within NordPool force TSOs to acquire sufficient reserve capacity in the RCM to cover a possible outage of the largest unit in their system. The RPM instead is utilized to trade UR and down regulation power. It aims to anticipate the excessive use of automatic reserves and to restore their availability. The UR and down regulation terms normally refer to the generation side. Therefore, from a demand perspective means the contrary. If UR is requested for generators, for active loads means down regulation and vice versa. For the Danish RPM case all bids can be submitted, adjusted, or removed until 45 min before the operating hour [24]. These are then collected and sorted with increasing prices for UR and decreasing prices for down regulation. Depending on the system congestions, the TSO will activate the cheapest regulating power. According to [24], since nowadays most of the demand is not active in the RPM it cannot benefit from its frequent low prices being forced to pay the cost of imbalances. Based on this, the RPM is considered an interesting environment to commercialize the potential services offered by the proposed control structure.

However, providing such services requires an accurate performance of the participating technology. Hence, the estimation of the system flexibility is an important aspect for a DSO-A willing to participate in the RPM. The UR and down regulation capabilities of an LV grid are normally represented by its maximum and minimum demand limits. So, based on the energy stored in HP and PEV loads in the LV system, a simple method is utilized to estimate, on an hourly basis, these limits. The estimation for the coming hour of the upper and lower flexibility bands ($\underline{\mathrm{FB}}$, $\overline{\mathrm{FB}}$), in kW, is made based on

$$\overline{\mathrm{FB}} = \frac{k_{\mathrm{up}}}{3600} \cdot \left(\bar{E}^{\mathrm{Tot}}_{\mathrm{PEV}} + \bar{E}^{\mathrm{Tot}}_{\mathrm{HP}} + \left[E^{\mathrm{Tot}}_{\mathrm{HP}}\right]_{\Delta t} + [E_{\mathrm{HL}}]_{1h}\right)$$
$$\underline{\mathrm{FB}} = \frac{k_{\mathrm{down}}}{3600} \cdot \left(\left[E^{\mathrm{Tot}}_{\mathrm{HP}}\right]_{\Delta t} + [E_{\mathrm{HL}}]_{1h}\right) \tag{9}$$

where k_{up} and k_{down} are the coefficients which make the estimation of $\underline{\mathrm{FB}}$ and $\overline{\mathrm{FB}}$ more or less conservative. $\bar{E}^{\mathrm{Tot}}_{\mathrm{PEV}}$ is the maximum energy consumption from PEVs, in kWh, that could be requested by the SSs during the estimated hour

$$\bar{E}^{\mathrm{Tot}}_{\mathrm{PEV}} = \sum_{i=1}^{n_{\mathrm{ss}}} \left(\mathrm{SOC}_{\mathrm{max}} - \mathrm{SOC}^{\mathrm{avg}}_{\mathrm{PEV}}\right) \cdot n^{\mathrm{ss}}_{\mathrm{pev}} \cdot C_{\mathrm{max}} \cdot k_{\mathrm{av}} \tag{10}$$

where $\mathrm{SOC}_{\mathrm{max}}$ is the maximum SOC at what the PEVs in an SS are allowed to be charged, $n^{\mathrm{ss}}_{\mathrm{pev}}$ the number of available PEVs in an SS. The word "available" refers to those plugged-in SS with available storage capacity. A PEV which is plugged-in but fully charged is not considered. C_{max} is the maximum battery capacity in kWh and k_{av} represents the expected PEV availability in the SS for the estimated hour. $\bar{E}^{\mathrm{Tot}}_{\mathrm{HP}}$ is the maximum energy consumption, in kWh, which could be requested by the HPs in an SS during the estimated hour

$$\bar{E}^{\mathrm{Tot}}_{\mathrm{HP}} = \frac{\sum_{i=1}^{n_{\mathrm{ss}}} \left(\mathrm{SOE}_{\mathrm{max}} - \mathrm{SOE}^{\mathrm{avg}}_{\mathrm{HP}}\right) \cdot \sum_{i=1}^{n_{\mathrm{ss}}} n^t_j \cdot \Delta E^t_j}{\mathrm{COP}} \tag{11}$$

where $\mathrm{SOE}_{\mathrm{max}}$ is the maximum SOE of the HWSTs and n^t_j is the number of HP systems with a type j HWST. ΔE^t_j refers to the energy capacity that corresponds to the hysteresis band of the type j HWST. The average energy consumption from the HPs in the LV grid during the last Δt period ($[E^{\mathrm{Tot}}_{\mathrm{HP}}]_{\Delta t}$) is calculated based on historical records. Δt represents the number of hours in the past which are considered to calculate $[E^{\mathrm{Tot}}_{\mathrm{HP}}]_{\Delta t}$. With this expression, it is assumed that the total consumption of the HPs during the estimated hour will be similar to the one consumed during the last Δt hours

$$\left[E^{\mathrm{Tot}}_{\mathrm{HP}}\right]_{\Delta t} = \frac{1}{\Delta t} \cdot \int_{t-\Delta t}^{t} P^{\mathrm{Tot}}_{\mathrm{HP}} \cdot dt; \quad P^{\mathrm{Tot}}_{\mathrm{HP}} = \sum_{i=1}^{n_{\mathrm{ss}}} P^{\mathrm{SS}}_{\mathrm{HP}}(i) \tag{12}$$

where $P^{\mathrm{Tot}}_{\mathrm{HP}}$ is the aggregated power consumption of HPs in the LV gird. Since the estimation is one hour ahead, it becomes important to estimate the behavior of the household during the hour in between. Therefore, based on historical records the average energy consumption of the household load for the mentioned period ($[E_{\mathrm{HL}}]_{1h}$) is estimated.

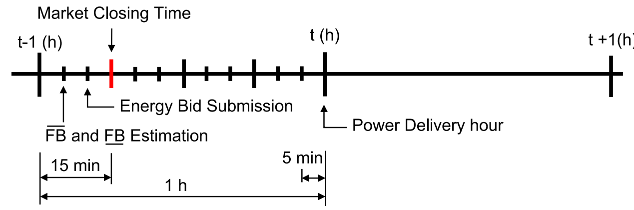

Fig. 4. Strategic procedure for the RPM participation.

Fig. 4 shows how the DGC should proceed when participating in the RPM. Since the market closes 45 min before each operating hour, the energy bid (E_{bid}) in kWh has to be submitted 5–10 min in advance. This means that $\underline{\mathrm{FB}}$ and $\overline{\mathrm{FB}}$ have to be automatically estimated few minutes before that in order to have the time to build E_{bid}. E_{bid} should always stay within the estimated limits to ensure its fulfillment. After the RPM clears, if the submitted E_{bid} is accepted the energy commitment (E_{ec}) is sent to the DSO-A. At the exact operating hour, it is required to satisfy the steady-state power demand related to E_{ec} (P_{ec}). So, considering the ramping time of the aggregated power demand from HPs and PEVs, the proposed mechanism activates those few minutes in advance. As it is described before, under an energy commitment the HP response is encouraged by ΔP. This is calculated as the difference between the active power measured at the ST (P_{st}) and the power demand related to E_{ec}

$$\Delta P = P_{\mathrm{st}} - \frac{E_{\mathrm{ec}}}{3600}. \tag{13}$$

For the PEVs instead, the DGC influences their charging rate for equalizing the SOE in the SSs and/or materializing an energy commitment. Therefore, when the DGC expects an RPM participation it forces in advance the SSs in LV grid to limit the $\mathrm{SOC}_{\mathrm{max}}$ of the PEVs in their domain to $\mathrm{SOC}^{\mathrm{RPM}}_{\mathrm{max}}$. The reason for doing so is to be able to utilize the $\mathrm{SOC}^{\mathrm{RPM}}_{\mathrm{max}}$-$\mathrm{SOC}_{\mathrm{max}}$ storage capacity for possible UR—seeing from the load perspective—in the future. It is worth to clarify that the discharging mode or V2G concept is not contemplated in this case. When an UR is requested the SSs will allow the PEVs charging up to $\mathrm{SOC}_{\mathrm{max}}$ utilizing this additional storage capacity. The materialization of down regulation is performed

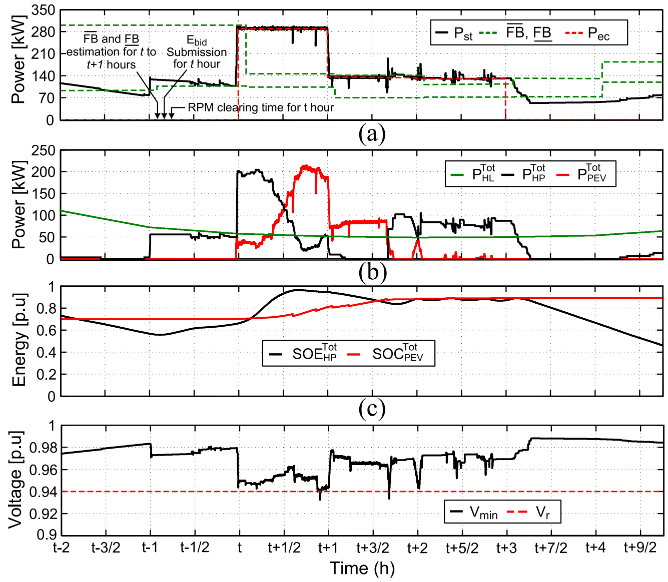

Fig. 5. Example of RPM participation. (a) P_{st}, $\underline{\mathrm{FB}}$, $\overline{\mathrm{FB}}$, and P_{ec}. (b) $P_{\mathrm{HL}}^{\mathrm{Tot}}$, $P_{\mathrm{HP}}^{\mathrm{Tot}}$, and $P_{\mathrm{PEV}}^{\mathrm{Tot}}$. (c) $\mathrm{SOE}_{\mathrm{HP}}^{\mathrm{Tot}}$ and $\mathrm{SOC}_{\mathrm{PEV}}^{\mathrm{Tot}}$. (d) $V_{\min}$ and V_r.

similarly as for the SS equalization problem. First, the SS with minimum SOE ($\mathrm{SOE}_m^{\mathrm{SS}}$) is determined based on the average $\mathrm{SOE}_{\mathrm{SS}\#i}$ received from the SS. Finally, by comparing $\mathrm{SOE}_m^{\mathrm{SS}}$ with the different $\mathrm{SOE}_{\mathrm{SS}\#i}$ the DGC assigns C_L to each of the SS (C_L^i) according to

$$\begin{aligned}&\mathrm{SOE}_{\mathrm{SS}\#i}-\mathrm{SOE}_m^{\mathrm{ss}}\geq\delta\rightarrow C_L^i=k_e\big(1-k_c\big(\mathrm{SOE}_{\mathrm{SS}\#i}-\mathrm{SOE}_m^{\mathrm{ss}}\big)\big)\\&\mathrm{SOE}_{\mathrm{SS}\#i}-\mathrm{SOE}_m^{\mathrm{ss}}<\delta\rightarrow C_L^i=k_e;\quad i=1\ldots n_{\mathrm{SS}}\end{aligned}\tag{14}$$

where δ is the SOE limit defined by the DSO to neglect any DGC influence in the PEV charging. k_s is the gain defining the slope of C_L. k_e is the variable used by the DGC to additionally limit the charging rate of PEVs under down regulation request.

In Fig. 5, an example of the DGC performance under a specific energy commitment is depicted. Fig. 5(a) shows the aggregated demand of the LV system in response to P_{ec}. Minutes after hour $t-1$, the DGC estimates $\underline{\mathrm{FB}}$ and $\overline{\mathrm{FB}}$ for the time frame t to $t+1$. Before the RPM closes, it submits its E_{bid} based on what it was predicted. After the RPM clearing, the bid gets accepted and an UR E_{ec} is received. Before hour t, the DGC, via the different SS, activates the flexible demand with the purpose of satisfying the energy commitment. As Fig. 5(b) depicts, the HPs are forced first to respond due to the lower accuracy in their demand control. As the times passes, the average SOE from all the HP systems in the LV network ($\mathrm{SOE}_{\mathrm{HP}}^{\mathrm{Tot}}$) increases meaning that their HWSTs begin to get filled [see Fig. 5(c)]. As a consequence, the aggregated HP demand ($P_{\mathrm{HP}}^{\mathrm{Tot}}$) decays and the PEVs take over the responsibility of maintaining the demand at P_{ec}. This causes an increase in the average SOC from all the PEVs in the system ($\mathrm{SOC}_{\mathrm{PEV}}^{\mathrm{Tot}}$). Notice, how due to the limitation imposed by the DGC prior P_{ec} is received, the PEVs are only allowed to charge up to $\mathrm{SOC}_{\max}^{\mathrm{RPM}}=0.7$ p.u. It is worth to underline how the flexibility estimated for the next hours gets significantly reduced due to the lack of storage capacity. Finally, Fig. 5(d) shows how

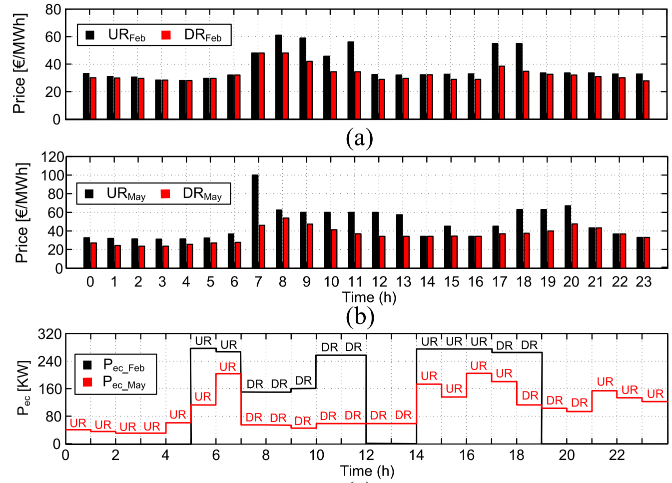

Fig. 6. Study cases. RPM prices in (a) February and (b) May. (c) Implemented P_{ec} signals in both scenarios.

the $V_{\min}$ of the LV network is importantly deviated due to the materialization of the energy commitment. However, the DGC successfully keeps it above V_r.

IV. LV Network and Study Cases

Motivated by the interest of assessing the performance of the control structure under the implemented upgrades, the LV test system used in [22] is also considered in this case. The relevant parameters about of the network and the R/X values of the grounded cables are available in [25]. Refer to the LV-II in that case. Through a 630 kVA 10/0.4 kV transformer and an eight string radial network, 166 residential consumers are supplied with electricity. A simple power flow analysis concluded that due to the HP and PEV load integration excessive voltage drops and overloading of the power infrastructure can be expected. This is especially relevant in string number 6 where for the winter case those are basically of unacceptable levels. Based on this calculation, the network was divided into nine SS.

For verifying these new features, the seasonal scenarios set in [22] are considered. The thermal consumption profiles from users in possession of HP systems and the DPs from those in possession of PEVs are available for two normal days in February and May. These profiles are essential to determine the electrical consumption pattern of these loads. Additionally, these scenarios are consummated with the consideration of the hourly RPM prices which were obtained from the NordPool Spot data base. Fig. 6(a) and (b) shows the UR and down regulation prices—from the generation perspective—representative of the months considered. It may be noted that during the peak hours, the prices increase in both cases. This is due to the need of generation capacity to balance the system load. In this context, an strategy for the DGC could be increasing the LV grid demand prior to the peak hours for benefiting from the low RPM prices and to store energy in the HWSTs and PEV batteries. Similarly, during peak hours, DSO-A could bid for a demand reduction aiding the system balance and a getting its economical revenue. Assuming that all the E_{bid} submitted by

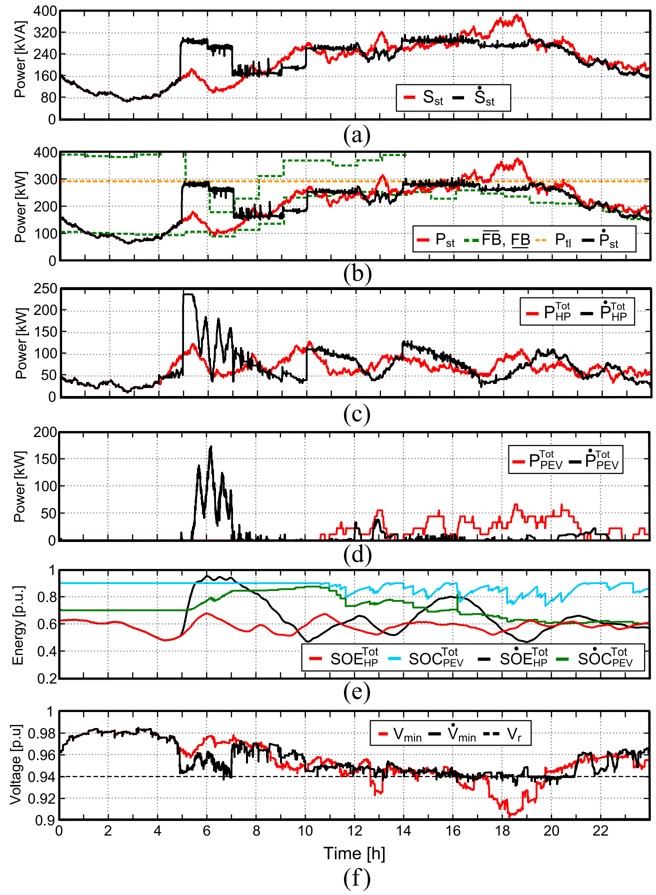

Fig. 7. Results for February. (a) Apparent power at the ST. (b) Active power demand at the ST, maximum limit due to technical constrains, and $\underline{FB}$ and $\overline{FB}$ bands. (c) Aggregated power demand from HPs. (d) Aggregated power demand from PEVs. (e) Average SOE and SOC from HPs and PEVs. (f) Minimum voltage in the LV network.

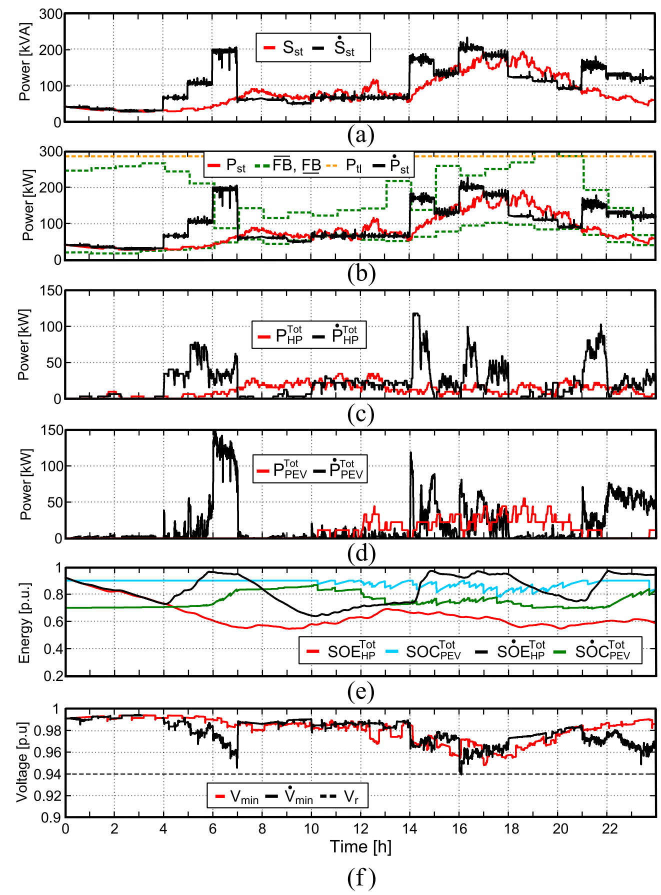

Fig. 8. Results for May. (a) Apparent power at the ST. (b) Active power demand at the ST, maximum limit due to technical constrains, and $\underline{FB}$ and $\overline{FB}$ bands. (c) Aggregated power demand from HPs. (d) Aggregated power demand from PEVs. (e) Average SOE and SOC from HPs and PEVs. (f) Minimum voltage in the LV network.

the DGC are accepted in the RPM, Fig. 6(c) shows the P_{ec} signals which need to be satisfied during the considered days. These are created taking into account also the flexibility available in each hour. Notice that the UR and DR in Fig. 6(c) are refereed to the load side. Therefore, in the following section, UR and DR will be considered from a load perspective.

V. Results and Discussion

To illustrate the benefits of the proposed control strategy, a RPM-based control case is compared to the noncontrolled case. So, to differentiate them, all the variables referring to the controlled case are denoted with the superscript "•." The obtained results are depicted in Fig. 7 for February and in Fig. 8 for May. Figs. 7(a) and 8(a) show apparent power measured at the ST (S_{st}), Figs. 7(b) and 8(b) show the active power measured at the ST (P_{st}), its maximum value defined by technical constrains (P_{tl}), and the estimated $\underline{FB}$ and $\overline{FB}$, Figs. 7(c) and 8(c) show the aggregated demand from HP systems (P^{Tot}_{HP}), Figs. 7(d) and 8(d) show the aggregated demand from PEVs (P^{Tot}_{PEV}), Figs. 7(e) and 8(e) show the average SOE and SOC from all the HP and PEVs systems in the LV system (SOE^{Tot}_{HP} and SOC^{Tot}_{PEV}), and Figs. 7(f) and 8(f) show the lowest supply voltage in the LV grid.

In February, comparing with other months, the power consumption of households in the LV network is higher. Additionally, the low atmospheric temperatures given in winter induce those to have high thermal power demand too. This aspect combined with the low COP values, representative of unfavorable atmospheric conditions, forces the HP systems to operate frequently. As a result, P^{Tot}_{HP} acquires a significant magnitude which takes up a large percentage of the system transfer capacity. On the top of that, in lack of a coordinated control of the PEV charging, the users tend to plug them as soon as they arrive home. As Fig. 7(f) shows the combination of these aspects, congests the LV network in several moments of the day. This is especially relevant from 17 to 19 h, where due to the demand synchronization from HP and PEVs during the HL peak moment, the V_{min} decays to 0.9 p.u. In this context, the DSO-A could define an RPM strategy, like the one designed in the previous section, to shift flexible demand to off-peak hours. This avoids congestions during the peak hours aiding the system balance at the same time [see Fig. 7(b)]. Notice, how the UR provided between 5 and 7 h allows filling the thermal and electrical storages of HP and PEV systems. As a consequence, the LV grid is able to reduce its power demand during the following hours aiding the system balance need reflected in the RPM prices. Furthermore, see how the materialization of any energy commitment impacts the $\underline{\text{FB}}$ and $\overline{\text{FB}}$ estimation for the subsequent hours. This is reasonable, since the available storage capacity of the flexible loads gets reduced as they are forced to operate. Therefore, it might happen that even if what is intended is to provide UR, the available flexibility forces the system to reduce the power consumption or vice versa. Another important aspect regarding the UR capability is the existing technical limit which defines the maximum power transfer capability of an LV network. Notice, how according to the estimated $\underline{\text{FB}}$ and $\overline{\text{FB}}$—$\overline{\text{FB}}$ not visible from 14 h on—the aggregated consumption of the LV network could actually be much higher considering the storage capacity available in HPs and PEVs. However, due to the existing technical limit imposed by excessive voltage drops the UR and DR capabilities of the system get considerably reduced. Even so, the RPM strategy selected forces the HP systems to shift their consumption to the period 14–17 h in order to avoid consumption during the peak period 17–19 h. Although, it might not seem to have very significant power reduction, when it is compared with the uncontrolled case of this is quite reasonable. As it is shown in Fig. 7(f), the RPM strategy selected improves $V_{\min}$ profile while allowing to acquire cheaper electricity and aiding the system balance.

In May, the aggregated power consumption of the households ($P_{\mathrm{HL}}^{\mathrm{Tot}}$) becomes lower facilitating an increase in the LV grid demand. At the same time, due to the higher temperature conditions, the thermal demand of households becomes lower and the COP higher, making the HPs operate less frequently. From a technical perspective, it means that the network gets less loaded and therefore there should not be any constrain limiting the RPM strategy designed by the DSO-A. The first thing to notice in Fig. 8(b) is how the magnitude of $\underline{\text{FB}}$ and $\overline{\text{FB}}$ gets reduced in comparison with February. The reason is a lower $P_{\mathrm{HL}}^{\mathrm{Tot}}$ and a lower average power consumption from the HPs ($[E_{\mathrm{HL}}]_{1h}$) influence in their estimation. This implies that the UR and DR capabilities of the LV system are affected by the season of the year considered. An interesting aspect, also given in February but in a less applicable manner, is how during the day hours $\underline{\text{FB}}$ and $\overline{\text{FB}}$ become narrower. This is caused by the departure of PEVs which represents a loss of available storage capacity. Finally, the RPM strategy selected shifts the power consumption of flexible loads to hours prior to the peak demand periods aiding the system balance again. This is done respecting the voltage limits established in the EN 50160.

VI. Conclusion

The electrification of the heating and transportation systems implies the accommodation of large numbers of HPs and PEVs in LV distribution grids. Despite the challenges presented for DSOs in the future, their flexible nature exhibits significant potential in the technical and commercial service procurement. This paper presents the new features implemented in the hierarchical structure proposed in previously for controlling the demand response in LV networks. This new design aims to satisfy the following aspects.

1) Be in accordance with the standard EN 50160.
2) Dismiss any end-user discrimination.
3) Materialize the energy committed determined by the RPM.

Its performance is validated and compared with an LV network currently in operation in Denmark. The results show the benefits for the DSO-A by participating in the RPM. On the one hand, they can obtain cheaper energy providing UR in the early morning and early afternoon hours. On the other hand, they can profit from providing down regulation during peak periods while decongesting the local network at the same time.

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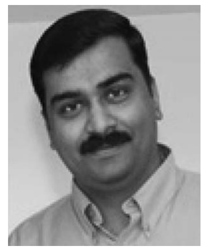

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