Modeling Demand Flexibility of RES-based Virtual Power Plants

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Abstract—In this paper, an approach to evaluate the benefits of demand flexibility for Virtual Power Plants (VPPs) is presented. The flexible demands chosen in this study are part of a renewable energy source-based VPP that participates in Day-Ahead Market (DAM) and Intra-Day Market (IDM) and has dispatchable and non-dispatchable assets. A demand model with bi-level flexibility is proposed: the first level is associated with DAM, whereas the second level is related to IDM sessions. Simulations are carried out considering a 12-node network to ascertain the eventual impacts of modeling demand flexibility on VPP operation. The market structure considered in the case study resembles the different trading floors in the Spanish electricity market. Results obtained show that the proposed demand flexibility scheme increases the overall profit of the VPP, as well as the revenues of the demand owners without disrupting the consumer’s comfort.

Index Terms—Day Ahead Market, Flexible Load, Intra-Day Market, Renewable Energy Sources, Virtual Power Plant

I. INTRODUCTION

Demand Side Management (DSM) for mutual benefits of consumer and the utility has been around for several decades. The definition, constituent parts and strategies for managing consumer’s load have also evolved through this time [1]. These strategies have included peak clippings, valley filling, load shifting, strategic conservation, strategic load growth, and flexible load shape, among others [2], [3]. Today, popular loads that have been included in DSM studies comprise electric vehicles (EVs) and large thermal-storage air-conditioning systems. These have been chosen largely due to their possession of storage and/or inertia provision capabilities. In many studies of load management however, a main challenge with DSM models is the absence of appropriate measures of benefits for consumers that provide such flexibility actions.

In [4], two types of load, flexible and non-flexible, were presented but assigning prices to this flexibility provision was not addressed. In a study with multiple Distributed Energy resources (DERs), EVs serving as controllable electrical loads were used as a source of flexibility for load shifting. The objective here was increasing profitability of the DER assets [5]. Similar to the previous study, authors of [6] proposed the utilization of flexible loads to absorb the variable renewable generation during the day instead of simply doing load shifting from peak demand periods to times of low prices in the middle of the night. Moreover, communication systems are increasingly permeating the power system with the usage of more Internet of Things devices. Thus, an information-rich energy system with flexible and responsive electrical loads that have storage capabilities can be built to respond to variable Renewable Energy Sources (RESs) [7].

While these advancements are noteworthy, studies have given less attention to load owners having full control over what value they assign to this flexibility provision. This question can be coupled with seeking a solution for the market participation of stochastic nondispatchable RESs. Aggregating RESs within a VPP is a solution to provide a better controlled output and to make RES more competitive in electricity markets [8]. In contrast to our present work, VPPs with flexible demands and who offer prices to those demand owners for their flexibility provision have not been taken into account in previous literature.

To fill this gap, a RES-based VPP incorporating flexible demand for flexibility provision while participating in energy markets is presented. We propose a demand model with bi-level flexibility associated with different energy market trading sessions. In contrast to other studies, the demand owner maintains high level of control over its own consumption by setting different profiles which the VPP manager can choose from in DAM at a cost. Moreover, the demand owner allows tolerances around the chosen profile at IDM at no cost. A network-constrained unit commitment model is formulated to submit VPP DAM auctions and then subsequently IDM bids to correct for deviations from forecasts and other variations.

In this study, we consider that the VPP participates in the Spanish energy market. The energy market in Spain is well tailored for the studies carried out in this work and the authors have extensive knowledge of its market structure. The methodology proposed can be readily applied in other energy markets with similar structure and trading sessions.

II. VPP MODELLING

This section presents the formulation of the VPP model used in this paper. The VPP comprises flexible demands (industrial, airport and residential loads), Dispatchable Renewable Energy Source (D-RES) (hydro), Non-dispatchable Renewable Energy Sources (ND-RESs) (wind power plant, solar PV) and Solar Thermal Unit (STU) with storage capability. These assets are distributed across the electrical network and connected to the main grid through one or more Points of Common Coupling (PCC). The VPP components and electrical network were presented in [8]. The business model considered for the VPP is the maximization of its aggregated profit by optimally scheduling the generation and demand assets in its portfolio.
The formulation for each asset class is discussed in the remainder of this section. D-RESs are modeled like conventional power plants \([9]\) with linearized operation costs of the dispatchable assets. Network constraints are formulated by using a DC power flow approximation \([10]\). D-RESs and DC power flow constraints are well-known and not discussed here due to space limitations. In addition, the STU model is adopted from \([11]\). The objective function of the VPP, and constraints for the energy balance at the PCCs and the ND-RESs are presented in the following subsections.

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\text{A. Nomenclature}
\]

This subsection presents the notation and nomenclature used in this section and in Section \([III]\)

Indexes and Sets

- \(b \in B\) / \(B^m\): Network Buses / Network buses Connected to Main Grid
- \(c \in C\) / \(C_b\): D-RES / D-RES connected to bus \(b\)
- \(d \in D\) / \(D_b\): Demand / Demand connected to bus \(b\)
- \(k \in K\): IDM sessions
- \(\ell \in L\): Network lines
- \(p \in P\): Demand profiles
- \(r \in R\) / \(R_b\): ND-RES / ND-RES connected to bus \(b\)
- \(t \in T\): Time periods
- \(\theta \in \Theta / \Theta_b\): STU / STU connected to bus \(b\)

Parameters

- \(C^0_b / C^t_b\): Shut-down/start-up cost of D-RESs \([\in]\)
- \(C^V_c\): Variable production cost of D-RESs \([\in/MWh]\)
- \(C_{d,p}\): Cost of load profile \(p\) of demand \([\in]\)
- \(E_d\): Min energy consumption of demand \(d\) throughout the planning horizon \([\text{MWh}]\)
- \(P_{d,t} / P_{d,t}\): Lower/upper bound variations of the power consumption of demand \(d\) in time \(t\) \([\%]\)
- \(P_{r,t}\): Min production of ND-RES in time \(t\) \([\text{MW}]\)
- \(\bar{P}_{d,p,t}\): Max hourly consumption of profile \(p\) of demand \(d\) \([\text{MW}]\)
- \(\bar{P}_{r,t}\): Available production of ND-RES in time \(t\) \([\text{MW}]\)
- \(P^m_b\): Maximum power that can be traded with the main grid at bus \(b\) \([\text{MW}]\)
- \(R_d / R_d\): Down/up ramping limit of demand \(d\) \([\text{MW/h}]\)
- \(\Delta t\): Duration of time periods \([\text{h, min}]\)
- \(\lambda_{DA}^t\): DAM price in time \(t\) \([\in/MWh]\)
- \(\lambda_{ID}^t\): Price of IDM session \(k\) in time \(t\) \([\in/MWh]\)

Variables

- \(p_{d,t} / p_{d,t}\): Total power traded in the DAM/IDM in time \(t\) \([\text{MW}]\)
- \(p_{r,t}\): Power flow through network of line \(\ell\) in time \(t\) \([\text{MW}]\)
- \(p_{\theta,t}\): Electrical power generation of STU in time \(t\) \([\text{MW}]\)
- \(p^m_b\): Power scheduled to be bought from/sold to the DAM and IDM markets at bus \(b\) in time \(t\) \([\text{MW}]\)
- \(p_{c,t}\): Power generation of D-RESs in time \(t\) \([\text{MW}]\)
- \(p_{d,t}\): Power consumption of demand in time \(t\) \([\text{MW}]\)
- \(\alpha_{d,p}\): Binary variable to select demand profile \([0/1]\)

\[
\text{B. Profit Maximization Objective}
\]

Due to small volumes of energy traded in the IDM relative to DAM and modest price differences between these markets in the Spanish system \([12]\), the objective functions in DAM and IDM are decoupled in this work. Each IDM further has associated constraints to cater for updates or changes in forecasts of stochastic sources. In DAM, the objective function \([1]\) is the maximization of the obtainable profit by the VPP assets calculated as the revenue from power trades minus cost of operating D-RES and cost of selecting a particular load profile. Operation cost of ND-RES are not considered in the objective function due to their relative low value when compared to costs of dispatchable sources. For the different IDM sessions, the benefit \([2]\) is calculated over changes in traded power \(\Delta p_{k,c,t}\) between: (i) DAM and first IDM trading period and (ii) other subsequent IDM sessions. Cost of choosing a specific load profile is not included while computing objective of IDM because this choice is previously made during DAM participation and must be accounted for only once.

\[
\begin{align*}
\max_{\in \text{DAM}} & \sum_{t \in T} \left[ \lambda_{\text{DA}}^t p_{\text{DA}, t} \Delta t - \sum_{c \in C} (C^V_c p_{c,t} \Delta t + c^0_{c,t} + c^1_{c,t}) \right] \\
& - \sum_{d \in D \ p \in P} C_{d,p} u_{d,p} \\
\max_{\in \text{IDM}} & \sum_{t \in T} \left[ \lambda_{\text{ID}}^t p_{\text{ID}, t} \Delta t \\
& - \sum_{c \in C} (C^V_c \Delta p_{k,c,t} \Delta t + c^0_{k,c,t} + c^1_{k,c,t}) \right], \quad \forall k \in K
\end{align*}
\]

E. Energy Balance

Energy balance constraints common to both market stages are modeled in \([3]\) whereas those specific to DAM and IDM are formulated in \([4]\) and \([5]\) respectively. Equation \((3a)\) gives energy balance at the PCC with the main grid, while \((3b)\) is the balance for all other buses in the VPP network at every time period \([13]\). The difference between both equations is presence of \(p^m_{b,t}\) at the main grid representing scheduled power to be traded with other market participants. This power available for trading (buy or sell) is set within prespecified bounds in \((3c)\).

\[
\begin{align*}
\sum_{c \in C_b} p_{c,t} + \sum_{r \in R_b} p_{r,t} + \sum_{\theta \in \Theta_b} p_{\theta,t} - \sum_{\ell_i(t)=b} p_{\ell_i,t} + \sum_{\ell_j(t)=b} p_{\ell_j,t} &= p^m_{b,t}, \quad \forall b \in B^m, \forall t \in T \quad (3a) \\
\sum_{c \in C_b} p_{c,t} + \sum_{r \in R_b} p_{r,t} - \sum_{\ell_i(t)=b} p_{\ell_i,t} + \sum_{\ell_j(t)=b} p_{\ell_j,t} &= \sum_{d \in D_b} p_{d,t}, \quad \forall b \in B \setminus B^m, \forall t \in T \quad (3b) \\
\bar{p}^m_{b,t} & \leq p^m_{b,t} \leq \bar{p}^m_{b,t}, \quad \forall b \in B^m, \forall t \in T \quad (3c)
\end{align*}
\]

1) DAM Formulation: Equation \((3)\) ensures that summation of traded power at all PCCs is equivalent to the total power available for trading by VPP.

\[
p_{\text{DA}}^t = \sum_{b \in B^m} p^m_{b,t}, \quad \forall t \in T
\]

2) IDM Formulation: For IDM sessions, the IDM offers/bids do not substitute those submitted in the DAM, but rather, they are adjustments of the DAM offers/bids as reflected
in (5). The rationale behind such adjustments can be due to unplanned maintenance of generators, changes in ND-RES outputs, demand changes and/or line faults.

\[ p_{t}^{DA} + \sum_{k=1}^{k-1} p_{t}^{ID} + \sum_{b \in B^m} p_{b,t} = \sum_{k \in K} p_{k,t}, \quad \forall k \in K, \forall t \geq \tau \quad (5) \]

where \( p_{t}^{DA} \) and \( p_{t}^{ID} \) are solutions of the DAM and previous IDMs respectively. Note that the only difference with respect to (3) is the time index, \( \forall t \in T \), which is replaced with \( \forall t \geq \tau \), where \( \tau \) is the first delivery period of current IDM session.

**D. Non-dispatchable Renewable Energy Sources**

The ND-RESs modeled in (6) comprise mainly wind power and solar PV plants. The lower bound represents the asset technical minimum (e.g., cut-in speed for wind plant) while the output is bounded above by the available stochastic source.

\[ P_{r,t} \leq p_{r,t} \leq \bar{P}_{r,t}, \quad \forall r \in R, \forall t \in T \quad (6) \]

**III. FLEXIBLE DEMANDS**

This section presents the model of the demand flexibility in a VPP participating in energy markets that is proposed in this work. The model comprises two levels of flexibility, each associated with DAM and IDM market sessions respectively.

**A. DAM Formulation**

An optimal load profile is selected during DAM as the first flexibility level. For each demand \( d \), (7a) and (7b) guarantees the choice of a single profile \( p \) out of all the available ones. Prior to market participation, various profiles are prepared by the demand owners/aggregators and communicated to the VPP manager. A particular profile might serve as the default, i.e., the consumption profile that will be followed by the demand if no market participation is considered. Additional profiles which the load owner can follow but might be operationally costly can be presented. However, compensation will be required from the VPP if those are chosen. Take an instance of residential demands; the default profile might feature double peaks at 09:00 and 20:00 whereas another profile features a shift of these load peaks to 07:00 and 21:00 respectively. If the second profile is selected as optimal by the VPP, the cost of operational inconvenience must be paid to the load owner.

\[ p_{d,t} = \sum_{p \in P} P_{d,p,t} u_{d,p}, \quad \forall d \in D, \forall t \in T \quad (7a) \]

\[ \sum_{p \in P} u_{d,p,t} = 1, \quad \forall d \in D \quad (7b) \]

**B. IDM Formulation**

The second level of demand flexibility is provided during the different IDM sessions, formulated in (8). At IDM, the load profile selected from DAM cannot be changed. However, the demand owner allows the VPP manager to vary the consumption within predefined threshold (symmetric or not) around that selected profile \( P_{d,p,t}^{*} \) as presented in (8a). Equations (8b) and (8c) define the ramps of the demand profile from one period to the next. Finally, (8d) ensures that, over the total duration of the current IDM session plus the periods covered in previous sessions, a minimum amount of energy is consumed. The energy values settled in previous periods, \( p_{d,t}^{*} \), are thus accounted for during subsequent IDM.

\[
(1 - P_{d,t}) P_{d,p,t}^{*} \leq p_{d,t} \leq (1 + P_{d,t}) P_{d,p,t}^{*}, \quad \forall d \in D, \forall t \geq \tau \quad (8a) \\
\]

\[
p_{d,t} - p_{d,(t-1)} \leq \bar{R}_{d} \Delta t, \quad \forall d \in D, \forall t \geq \tau \quad (8b) \\
\]

\[
p_{d,(t-1)} - p_{d,t} \leq R_{d} \Delta t, \quad \forall d \in D, \forall t \geq \tau \quad (8c) \\
\]

\[
E_{d} \leq \sum_{t=1}^{\tau-1} p_{d,t}^{*} \Delta t + \sum_{t=\tau}^{\tau+1} p_{d,t} \Delta t, \quad \forall d \in D \quad (8d) \\
\]

**IV. CASE STUDY**

This section presents the case studies considered to test and validate the RES-based VPP model proposed in this paper. Section IV-A outlines the VPP topology considered, which resembles a subarea of the southern region of the Spanish grid. The input data that for the model is described in Section IV-B.

**A. VPP Description**

The VPP assets are distributed across a 12-node network connected to a main grid through the PCC (bus 5) as shown in Fig. 1. The demands considered are industrial, airport and residential loads (buses 3, 9 and 12) with minimum daily consumption of 800, 580, and 600 MWh respectively. Three profiles are associated with each demand and total consumption for each profile is the same. Capacity of hydro (bus 6) is 111 MW. Wind power plant (bus 4), solar PV (bus 8) and STU (bus 1) each have capacities of 50 MW.

![12-node network for test cases](image)

**B. Input Parameters**

A time horizon of 24 hours with an hourly resolution is utilized during DAM, while a subset of the 24 hours is used for each IDM session (see [12]). Figure 2 shows the three profiles considered for each of the loads. The basecase profile simulates default activities of electricity consumers (see Section III-A). The other two profiles (early and late peaks) are designed to perform load shifting around the basecase. Other profiles can also be easily added to capture other modes of demand interaction with the market. During IDM, the demand owner allows a percentage of tolerance for demand movement over the selected profile at DAM. In this case study, symmetric tolerances from 10–50% over the total demand are considered. Note that the highest tolerance values considered serve only as an illustrative study, as likely no demand owner would allow such variations in a short notice (sometimes as short as 1 hour).
V. RESULTS

To test the effectiveness of our model using renewable sources, two distinct operation days are identified: a clear sunny day and a day with intermittent cloud covers. Two aspects are thoroughly discussed for each day, namely: a) optimal price to be offered by the VPP to the demand owners and b) effect of the flexibility provided by demand on the profits accrued and operation of the VPP.

A. Optimal Price Offered by VPP to Demand Owners

First, we provide a solution to the benefits for demand owners and show that there is a maximum daily total \((C_{d,p})\) and a price per MWh that the VPP is prepared to pay demand owners such that it is still profitable. The default load profile has zero cost because the demand owner follows it regardless of other events. VPP then decides what price to pay demand owners for other profiles such that it’s benefits are not eroded.

1) Clear day: The optimal choices of demand profiles obtained for VPP operation on a clear day is shown in Table I. These are obtained when \(C_{d,p}\) for every other profile is set to zero. Industrial and residential loads have the early peak and late peak as optimal profiles respectively. To determine the cut-off costs before the basecase is selected, costs for other demand profiles are then gradually increased (simultaneously for all demands). It was then observed that the VPP manager is only willing to pay up to €320/day to the industrial load owner. The availability of the default profile \((C_{d,p} = 0)\) acts as an economic viability check for the VPP. The €320 is thus the maximum price offering for the early peak industrial load profile, after which it is no more profitable for VPP. The industrial late peak profile is not profitable at all and neither is the residential early peak profile. In the case of the airport load, there are more options for both the airport demand owner and the VPP manager. The early peak profile is profitable for the VPP manager as a cost up until €500/day while the late peak profile is only profitable until €305/day.

As observed in Fig. 2, the different airport profiles have only subtle differences. Additionally, the load profiles have a benefit-inducing relationship with the evolution of the market price on this clear day. Indeed, the first profile peaks (periods 8-10) correspond to lower electricity prices and thus account for the higher costs which the VPP is prepared to pay. When the demand cost per MWh of the optimal profiles are computed, proof of the hypothesis is further demonstrated. For the airport profiles, \(C_{d,p} = €10.42/MWh\) for 48 MWh shifted and €7.44/MWh for 41 MWh shifted of the early and late peak profiles respectively. Contrast this with industrial early peak profile where \(C_{d,p} = €4.35/MWh\) for 73.5 MWh shifted. Thus, the €/day offer from VPP depends a little less on the magnitude of energy shifted and more on the load profile shape with respect to market price. Finally, these costs per MWh associated with DAM represent lower bounds on the price that VPP is willing to pay demand owners. With the tolerances allowed in IDM, VPP benefits increase and the prices paid to demand owners are expected to follow the same trend.

2) Cloudy day: On a cloudy day, it is observed that for all demands, the late peak profile is not optimal for the VPP operation. Additionally, the VPP manager is unwilling to pay amounts as high as the clear day case. Only €90/day and €260/day is offered to the industrial and airport load respectively. For the residential load, the deviations from the default load are not optimal at all and the VPP manager thus, offers no price to the residential load owner.

B. Effects of Demand Flexibility on VPP Profits

This section discusses: 1) effects of demand flexibility on profitability of the VPP and 2) effects of percentage flexibility allowed by the demand owners.

On a clear day, the VPP manager can realize a profit of €68,259 from participating in the DAM (first demand flexibility level). However, at the end of the operation horizon (i.e. final IDM session), this profit can increase by up to 14% attributable to the second demand flexibility level alone beyond its DAM objective. The relationship between second-level flexibility allowance and the associated effect on profits is shown in Fig. 3. Beyond 40%, profits do not show any...
considerable additional increase and any allocation on load movement beyond this percentage only leads to more saturation on the profits curve.

![Graph showing energy consumption over time with different flexibility allowances.]

Fig. 3. Demand profile flexibility on VPP profits on a clear day

Figure 4 shows the impact of demand flexibility on total power traded in DAM and total traded after all IDM sessions. It is observed that increasing flexibility provision reduces the valley in DAM offer around the instant \( h = 8 \) and leads to an increase in offers in the energy market while at the same time flattening the curve in the straight section from periods 9 to 19 but keeping total energy consumption constant.

![Graph showing scheduled and final demand outputs on a clear day with different flexibility allowances.]

Fig. 4. Scheduled and final traded power based on demand flexibility

Final demand output relative to DAM offer is shown in Fig. 5. Up to 20% flexibility allowance on demands, the variations are smooth and would not necessarily alter normal system operation. However, from 30% and upwards flexibility, higher consumption pattern is observed in demand as evidenced in the industrial and residential demands at periods 10-13 and 17-19. Increasing flexibility allowance gives rise to more of this peaks that might affect system performance. Demand owners would likely not allow such percentages anyway and we simply show a proof of concept here.

![Graph showing scheduled and final demand outputs on a clear day with different flexibility allowances.]

Fig. 5. Scheduled and final demand outputs on a clear day

VI. CONCLUSION

This paper presents a model for evaluating the impacts of flexibility provision by demands that are part of an RES-based VPP that participates in energy markets. The flexible demand model proposed has two levels of flexibility associated with different market sessions. The business model of the VPP is such that it maximises its profit by dispatching its generators, carrying out self supply of the demands within its portfolio and utilizing the flexibility actions provided by said demands.

Case studies were then analysed to determine the optimal price the VPP is ready to offer demand owners. Impact of the flexibility provided on operation of VPP and profits accrued at the end of the operation day is also discussed. Based on the studies carried out, it is concluded that there is a maximum price offering from VPP to demand owners for each demand profile. Beyond this price, the default load will be selected.

A sensitivity analysis showed that beyond 40% flexibility allowance for the demands studied, there is a saturation of the profit and added flexibility might not be anymore profitable.

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