Optimal Bidding by Aggregator of Energy Community in the DSO Flexibility Market

Mahtab Kaffash
New Business and Net Zero
Centrica
Antwerp, Belgium
Mahtab.Kaffash@centrica.com

Fairouz Zobiri
New Business and Net Zero
Centrica
Antwerp, Belgium
Fairouz.Zobiri@centrica.com

Ajay Kumar Sampathirao
New Business and Net Zero
Centrica
Antwerp, Belgium
AjayKumar.Sampathirao@centrica.com

Vladimir Vrabel
New Business and Net Zero
Centrica
Antwerp, Belgium
Vladimir.Vrabel@centrica.com

Benjamin Krikler
New Business and Net Zero
Centrica
Antwerp, Belgium
Benjamin.Krikler@centrica.com

***Abstract*—This paper presents an optimal bidding algorithm to identify the available flexibility in a renewable energy community (REC) for providing flexibility to the local distribution system operator (DSO) or a nearby REC. This algorithm enables the use of flexibility by the DSO or nearby REC to address local grid congestion without the need for further investment in the local grid. The optimization is formulated as a linear problem, taking into account models for flexible assets and the energy constraints of the REC, using information from the day-ahead and imbalance markets. In addition to determining the optimal value of flexibility, the optimization framework calculates the opportunity cost for the REC to provide this service. This algorithm has been tested on a REC with PV-battery systems. The results demonstrate not only the optimal available flexibility but also provide the optimal bidding cost that the REC can offer. Specifically, the tests show how the algorithm efficiently balances the supply and demand within the REC, calculates the most cost-effective bids, and maximizes the economic benefits for the REC. Furthermore, the results highlight the potential revenue and the ability for DSOs to leverage flexibility from the local community.**

***Index Terms*—bidding strategy, energy communities, energy flexibility market, local grid**

I. Introduction

One of the primary objectives of the European Union (EU) Clean Energy Package is to empower consumers to actively participate in the EU energy systems. In pursuit of these energy transition goals, the EU has introduced the concept of Renewable Energy Communities (RECs) within the package [1]. RECs allow citizens to collectively produce and manage their own renewable energy. Despite strong interest from citizens and communities, projects related to energy communities are still in their early stages, necessitating significant efforts to realize their potential across the EU [2], [3].

In addition to the above challenge, the distribution system operator (DSO) flexibility market is crucial for managing the complexities of modern power systems, integrating renewable energy, maintaining grid stability and reliability, and enabling a more efficient, cost-effective, and environmentally friendly energy landscape [4]. The impact of REC on the distribution systems was analyzed in [5].

To this end, this paper focuses on developing an optimal aggregated bidding strategy that can be offered by REC to the local DSO or nearby REC . Unlike [6] which focuses on optimal bidding in day-ahead market for aggregators, this paper not only determines the optimal value of flexibility but also calculates the opportunity cost for the REC to provide this service. The concept of the proposed bidding aggregation algorithm in this paper is similar to the one proposed in [7]. However, this paper focuses on daily operation of REC.

The main novelty of this paper is the development of a bidding algorithm that enables small flexible assets (at the level of a single household) to participate in the DSO market and receive revenue for providing this service. The rest of this paper is organized as follows. The problem is formulated in Section II. Section III discusses the case study and the simulation results. Finally, the paper is concluded in Section IV.

II. Problem Formulation

In this section, an algorithm is developed to identify the available flexibility in a community that can be provided to the DSO flexibility market. This algorithm has the following steps:

1) Determine the day-ahead optimal schedule in the community.
2) Identify the optimal deviation from day-ahead schedule and compensate for this deviation in the imbalance market.
3) Calculate opportunity cost.
4) Calculate the optimal values of flexibility that community can offer and/or bid to DSO market.

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5) Send out DSO the flexibility (both quantity and price) that the aggregator can provide.

A sequential market is assumed in this paper, where the DSO flexibility market is followed by the day-ahead wholesale market. Additionally, it is assumed that the aggregator has perfect knowledge of PV generation, household consumption, and imbalance prices. In this paper, the battery is the only source of flexibility in each household, while it is assumed that PV production cannot be curtailed.

In the rest of this section, the above algorithm is formulated. It is important to note that in this paper, lower-case letters in equations represent the variable of optimization, while the upper-case letters show the parameters of the problem.

The use case considered is a community comprising different households, each equipped with a PV-battery system. Other types of flexible assets can also be added; however, modeling different types of assets is beyond the scope of this paper. The model for other types of assets, such as heat pumps (HP) and electric vehicles (EV), can be integrated into the following optimization problem in future work. It is assumed that the aggregator also serves as the energy supplier for the energy community, and day-ahead energy prices are applied to end-users through dynamic pricing tariffs.

A. Optimal schedule in day-ahead market

The following optimization will run for each household to minimize the cost of electricity in day-ahead market:

$$\min \quad \sum_{t=1}^{T} e_{grid,DA}(t) \times C_{DA}(t), \tag{1}$$

where C_{DA} is electricity day-ahead price, and $e_{grid,DA}(t)$ is the energy exchanged with the grid in day-ahead market at time step t. T refers to the optimization horizon. $e_{grid,DA}(t)$ can be positive, if the household consumes energy from the grid, or negative in case of injection to the grid.

The constraints for this optimization can be formulated as:

1) Household energy balance:

$$e_{grid,DA}(t) = L(t) + e_{bat}(t) - PV(t) \quad \forall t \in [1, T], \tag{2}$$

where $L(t)$ is the load of household, $PV(t)$ is the energy produced by PV system of that household at time t, and $e_{bat}(t)$ is the energy to charge (positive value) or discharge the battery (negative value) at time t. This equation ensures energy balance at the point of household connection to the grid.

2) Battery model: The battery state-of-energy is given by:

$$soe(t) = soe(t-1) + \eta \times e_{bat}(t) \quad \forall t \in [1, T] \tag{3}$$

where $soe(t)$ is state-of-energy for the battery at time t, and η is the efficiency of the battery.

$$SoE_{min} \leq soe(t) \leq SoE_{max} \quad \forall t \in [1, T] \tag{4}$$

where SoE_{min} and SoE_{max} are the minimum and maximum battery state-of-energy limits, respectively.

$$-P_{max} \times \Delta t \leq e_{bat}(t) \leq P_{max} \times \Delta t \quad \forall t \in [1, T] \tag{5}$$

where P_{max} is the maximum charging and discharging power for the battery, and Δt in the time interval.

$$soe(T) = SoE_{init} \tag{6}$$

where SoE_{init} is the initial state-of-energy of the battery. Equations (3) - (6) are referring to the model of the battery.

By solving the above optimization problem, one can determine the optimal schedule of battery for each household in the community. As bidding into the TSO market is not within the scope of this paper, it is assumed that the aggregator acts solely as a price-taker. Therefore, the aggregator begins to optimize its portfolio based on the day-ahead market clearing price.

B. Optimal interaction in imbalance market

n order to provide flexibility to the DSO, the aggregator must deviate from the day-ahead optimal schedule of each flexible device in the portfolio. This deviation from the day-ahead schedule creates an imbalance in the grid. Therefore, the aggregator must manage imbalance prices (which are typically higher than day-ahead prices) to correct this deviation.

The following optimization will run for each household to identify the optimal deviation from day-ahead schedule:

$$\min \quad \sum_{t=1}^{T} \Delta e_{grid}(t) \times C_{IM}(t) \tag{7}$$

where C_{IM} is the electricity price in imbalance market, and $\Delta e_{grid}(t)$ is the amount of energy that should be exchanged in the imbalance market. This variable refers to the deviation from optimal $e_{grid,DA}(t)$ value to provide flexibility to DSO from each household in the community. In other words, $\Delta e_{grid}(t)$ means how much flexibility can be available and provided to DSO flexibility market by each household in the community.

The constraints for this optimization can be formulated as:

$$\Delta e_{grid}(t) = e_{grid,new}(t) - E_{grid,DA}(t) \quad \forall t \in [1, T] \tag{8}$$

where $e_{grid,DA}(t)$ can be provided by solving the day-ahead optimization problem formulated in Section II-A.

The new day-ahead energy interaction with the grid is evaluated as follows:

$$e_{grid,new}(t) = L(t) + e_{bat,new}(t) - PV(t) \quad \forall t \in [1, T] \tag{9}$$

where $e_{grid,new}(t)$ is the new value for energy exchanged in the day-ahead market, and $e_{bat,new}(t)$ is the energy to charge (positive value) or discharge the battery (negative value) the battery at time t. Similar to equations (3) - (6), Equations (10) - (13) refer to the model of the battery.

$$soe_{new}(t) = soe_{new}(t-1) + \eta \times e_{bat,new}(t) \quad \forall t \in [1, T] \tag{10}$$

$$SoE_{min} \leq soe_{new}(t) \leq SoE_{max} \quad \forall t \in [1, T] \tag{11}$$

$$-P_{max} \times \Delta t \leq e_{bat,new}(t) \leq P_{max} \times \Delta t \quad \forall t \in [1, T] \tag{12}$$

$$soe_{new}(T) = SoE_{init} \tag{13}$$

By solving the above optimization problem, one can determine the optimal deviation from the day-ahead schedule for each household in the community. This deviation refers to the value of flexibility that each household can provide to the DSO. This deviation is compensated in the imbalance market later.

C. Provide flexibility to DSO

In the previous section, the optimal value of flexibility which can be offered to DSO was identified. In this section, we first calculate the opportunity cost associated to this flexibility and then calculate the regulation side of available flexibility.

The opportunity cost ($OC(t)$) at each time step for each user of the community can be calculated as:

$$OC(t) = \frac{\sum_{i=1}^{T} \Delta e_{grid}(i) \times C_{IM}(i)}{\Delta e_{grid}(t)} \quad \forall t \in [1, T] \tag{14}$$

In this equation, the numerator represents the total cost of deviation from the optimal day-ahead schedule over the optimization horizon, while the denominator represents the energy deviation from the main grid compared to the day-ahead optimal schedule at each time step. $\Delta e_{grid}(t)$ can be a positive or negative value. The sign of this variable defines the regulation side of flexibility. In fact, the flexibility can offer in both sides, up or down. Up regulation is referring to negative imbalances, when the amount of consumption is higher than the amount of generation in the grid. In this case, the flexibility can be offered to system operator to either increase the generation or reduce the consumption in the grid to solve the mismatch problem. This means that if $\Delta e_{grid}(t)$ is negative, an up regulation can be offered to DSO, and the curtailed consumption can be recovered from imbalance market later. Equations (15) and (16) are calculating the value of this optimal offer and its associated opportunity cost.

$$offer(t) = max(0, -\Delta e_{grid}(t)) \quad \forall t \in [1, T] \tag{15}$$

$$OC_{offer}(t) = max(0, OC(t)) \quad \forall t \in [1, T] \tag{16}$$

On the other hand, down regulation is referring to positive imbalances, when the amount of generation is higher than the amount of consumption in the grid. In this case, the user can bid its available flexibility in to the market of system operator to either increase the consumption or reduce the generation in the grid to solve the mismatch problem. This means that if $\Delta e_{grid}(t)$ is positive, a down regulation can be offered to DSO, and the added extra consumption can be supplied from the imbalance market later. Equations (17) and (18) are calculating the value of this optimal bid and its associated opportunity cost.

$$bid(t) = max(0, \Delta e_{grid}(t)) \quad \forall t \in [1, T] \tag{17}$$

$$OC_{bid}(t) = max(0, -OC(t)) \quad \forall t \in [1, T] \tag{18}$$

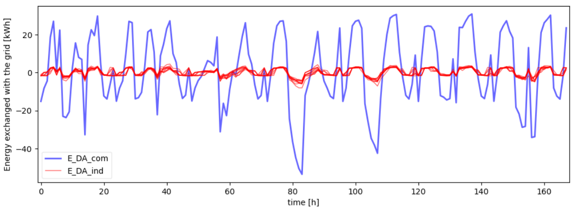
Based on the algorithm proposed in this paper, the aggregator can first identify the optimal bids and offers from each member of the community. Then, the aggregated flexibility can be calculated by summing up all the bids and offers of individual members. These aggregated bids and offers can be provided to the DSO. Finally, the DSO can decide whether to accept the provided flexibility to solve the congestion issues in the local grid or reject it. DSO's decision will communicate to the aggregator and then the aggregator will send out the control signal to single asset accordingly. If the flexibility bids and offers are accepted by DSO, then the new set points based on the new schedule will be sent to flexible assets. Otherwise, the optimal day-ahead schedule will be followed.

III. Simulation results and discussion

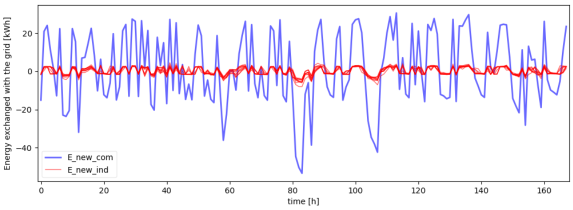
In this paper an algorithm is designed to offer flexibility available in a community to DSO to solve congestion in the local grid. The algorithm was formulated in the previous section as a linear problem. To test the proposed algorithm, a community including 10 households with user-owned PV and battery systems is assumed. The time series data related to electricity consumption and PV production of these 10 households are used to evaluate the algorithm. The energy capacity of the battery is set to 10 kWh for each household, which represent the maximum state-of-energy in a battery. The minimum state-of-energy is set to zero for all the batteries. The SoE_{init} for each battery in the community was selected randomly between its maximum and minimum state-of-energy. These values are selected randomly between minimum and maximum value of state-of-energy.

The day-ahead and imbalance prices were downloaded directly from the website of European Network of Transmission System Operators for Electricity (ENTSO-E) [8]. Moreover, in order to analyse the seasonality behavior, two scenarios are considered here: one week starting from 9 September 2022 (when there is more PV production), another one from 12 December 2022 (when there is less PV production and more demand). The analysis is done based on a 1 hour resolution.

By giving the above input parameters to the algorithm, figures 1 - 7 show the simulation results over two weeks of data for individual households and community. Fig. 1(a) and Fig. 2(a) show the results of energy exchanged with the main grid with the optimal day-ahead schedule for one week in September and one week in December, respectively. While Fig. 1(b) and Fig. 2(b) show the results of optimal deviation from the day-ahead schedule after providing flexibility to the DSO in September and December, respectively. In these

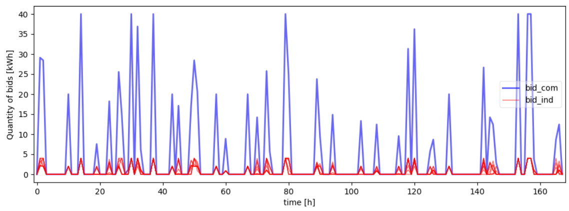


(a) September grid exchanges

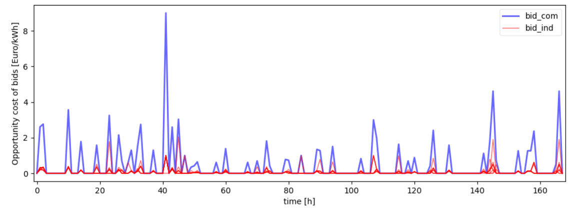


(b) September grid exchanges

Fig. 1. Individual (red) and community (blue) energy exchanged with main grid in September. (a) Optimal day-ahead energy exchanged. (b) A new day-ahead energy exchanging with the grid when offering flexibility to DSO.

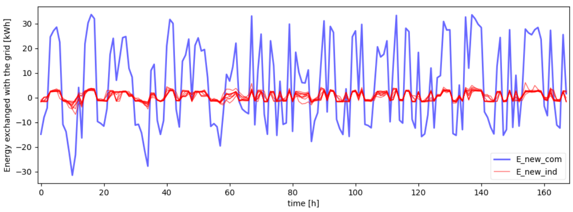


(a) Quantity of optimal bidding in September

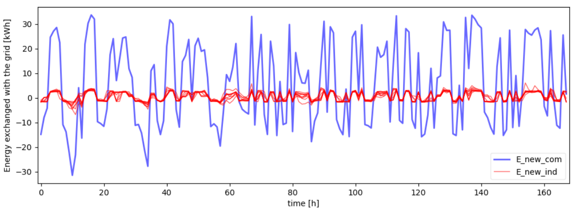


(b) Opportunity cost of bids in September

Fig. 3. Individual (red) and community (blue) optimal bids and their opportunity cost in September in DSO market. (a) Value of bids. (b) Opportunity cost of bids.

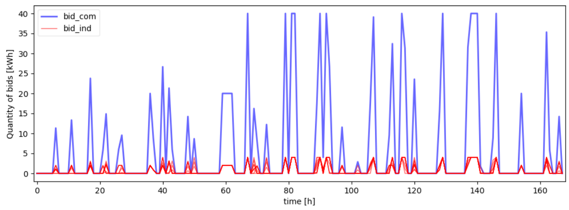


(a) December grid exchanges

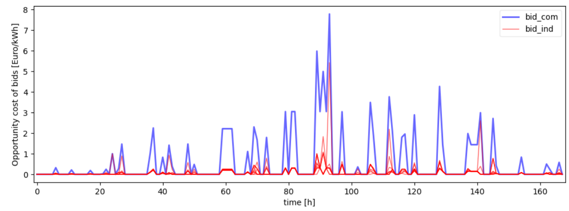


(b) December grid exchanges

Fig. 2. Individual (red) and community (blue) energy exchanged with main grid in December. (a) Optimal day-ahead energy exchanged. (b) A new day-ahead energy ex- changing with the grid when offering flexibility to DSO.



(a) Quantity of optimal bidding in December



(b) Opportunity cost of bids in December

Fig. 4. Individual (red) and community (blue) optimal bids and their opportunity cost in December in DSO market. (a) Value of bids. (b) Opportunity cost of bids.

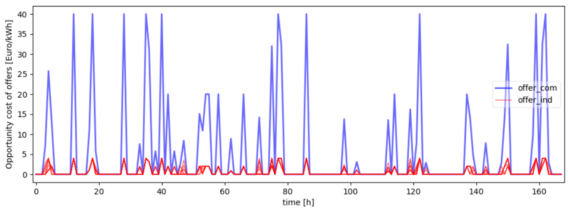
figures, the red lines represent the energy usage of individual community members, while the blue line is the summed result of the full community.

Fig. 3 illustrates the optimal bids and their opportunity cost that community can provide to the DSO in September, while Fig. 4 shows the results of optimal bidding in December.

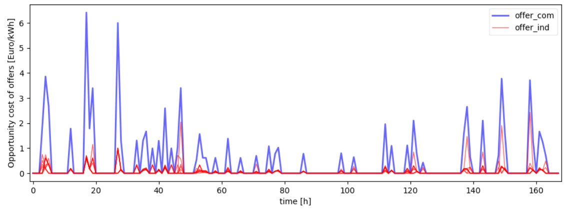
Fig. 5 illustrates the optimal offers and their opportunity cost that community can provide to the DSO in September, while Fig. 6 shows the results of optimal offers in December.

In order to show the impact of providing flexibility to the DSO on the behavior of battery, Fig. 7 shows the state-of-energy of the battery in optimal day-ahead schedule and in the case of providing flexibility to the DSO. As can be seen, in the day-ahead schedule, the battery started charging when the price of electricity was low or there was a surplus PV production, and then discharging when the prices were high or there was no PV generation. However, this statement is no longer valid when the battery provides flexibility to the DSO. As can be seen from the red lines, the battery started charging when the day-ahead price was high or discharging when the price was low. The financial difference is compensated via opportunity cost.

It should be mentioned that the aggregation of the offers will be done by summing up the individual offers (for some households, this value is zero). In the same way as offers, aggregated bids can be calculated. Therefore, it is possible

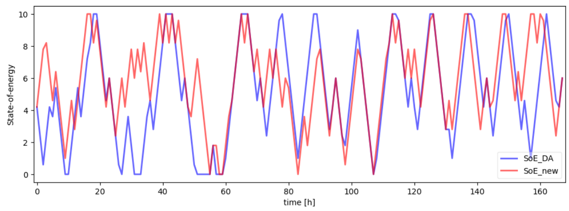


(a) Quantity of optimal offering in September

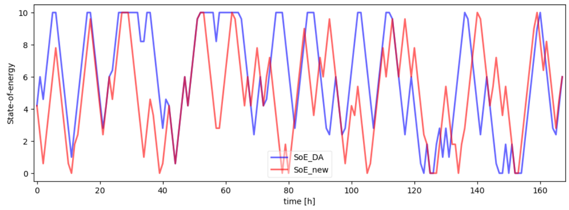


(b) Opportunity cost of offers in September

Fig. 5. Individual (red) and community (blue) optimal offers and their opportunity cost in September in DSO market. (a) Value of offers. (b) Opportunity cost of offers.

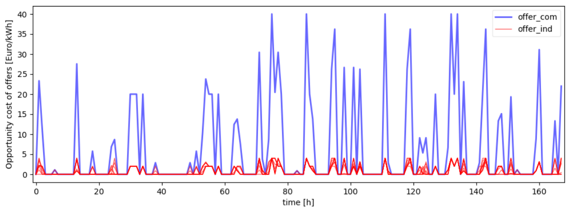


(a) SoE of a battery for one of the households in September

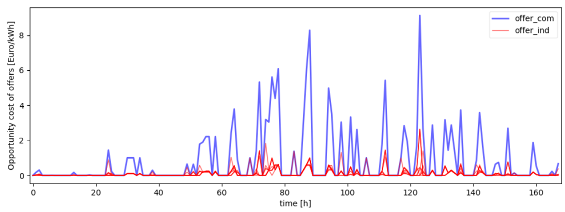


(b) SoE of a battery for one of the households in December

Fig. 7. SoE of a battery for one of the households, (a) in September, and (b) in December. Blue lines represent the optimal SoE in DA market, while red lines represent the SoE while providing flexibility for DSO.



(a) Quantity of optimal offering in December



(b) Opportunity cost of offers in December

Fig. 6. Individual (red) and community (blue) optimal offers and their opportunity cost in December in DSO market. (a) Value of offers. (b) Opportunity cost of offers.

that for the community, for the same time step, the aggregator can provide both down (bid) and up (offer) regulations to the DSO. However, the opportunity cost will be different for each of these two regulations. Ultimately, it is up to the DSO to select which one is needed for the grid.

In this paper, the designed solution was proposed. As the next step in the LocalRES project, the proposed approach will be applied to some demonstration sites involved in the project. To apply this to real-life cases, we need a more mature market design for DSOs across Europe. Moreover, to make the solution ready for real-life application, some assumptions in this paper, such as having perfect knowledge about day-ahead and imbalance prices, as well as PV and consumption data, should be replaced by various forecasting techniques.

IV. Conclusion

In this paper, an algorithm was designed to identify the available flexibility in a renewable energy community to participate in the DSO market. By running this algorithm, the aggregator can first identify the optimal bids and offers (both quantity and opportunity cost) from each member of the community. Then, the aggregated flexibility can be calculated by summing up all the bids and offers of individual members. These aggregated bids and offers can be provided to the DSO. Finally, the DSO can decide whether to accept the provided flexibility to solve the congestion issues in the local grid or reject it. The DSO's decision will be communicated to the aggregator, who will then send out the control signals to individual assets accordingly. If the flexibility bids and offers are accepted by the DSO, then new set points based on the new schedule will be sent to the flexible assets. Otherwise, the optimal day-ahead schedule will be followed.

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