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Demand response: For congestion management or for grid balancing?

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ABSTRACT

The growing capacity of intermittent energy sources causes more frequent system imbalances as well as congestion. Demand flexibility is a valuable resource that can be used to resolve these. Unfortunately, flexibility can also contribute to congestion, particularly when used to balance the grid. Using flexibility to solve grid problems without creating new ones requires well-designed financial incentives. Congestion management mechanisms (CMMs) are a primary example of such incentives. The question is which of these is most effective in preventing congestion with minimal impact on trading on the imbalance market. This question is answered by comparing traditional CMMs such as grid tariffs to a local flexibility market on their impact on the load in the grid and the lost value of flexibility on the imbalance market. This analysis shows that energy tariffs are not suited for preventing congestion. Capacity tariffs are able to prevent congestion but they impose limitations on the consumer which significantly reduce the value of flexibility on the imbalance market. The flexibility market, an example of a local market, is effective if aggregators do not have a position day ahead or if the distribution system operator limits the buying of flexibility a day before delivery.

1. Introduction

Due to the growing capacity of intermittent energy sources, flexibility in energy has been recognized as an increasingly important asset (Martinot, 2016). Particularly, flexibility could be used to balance the grid, i.e., ensure that at every moment electricity consumption is equal to electricity production. Grid balancing is a responsibility of the Transmission System Operator (TSO) and, as long as energy cannot be efficiently stored, is essential for a stable supply of electricity. Currently the balancing service to the TSO is provided mostly by conventional power plants that are being phased out by renewable energy sources in pursue of European climate goals. However, many of the renewable energy sources lack flexibility to replace thermal power plants in grid balancing, hence flexibility needs to be found elsewhere, e.g. in batteries or devices that consume electricity.

The increased need for flexibility led to the creation of a new role in the energy landscape: an aggregator, a party that groups together and manages flexible loads of multiple grid users (Andreia et al., 2017). The consumers allow an aggregator to manage their flexibility for a promise of a financial reward, which makes it the aggregator's objective to minimize the cost of consuming electricity. Flexibility can be monetized on electricity markets, e.g. the imbalance market. To do that, an aggregator could choose to shift the flexible consumption from periods of shortage of supply, characterized by high imbalance prices, to periods of power oversupply, characterized by low imbalance prices, and receive payment from the imbalance market for performing such action.

This form of flexibility to provide balancing capacity, called demand response, is already used by energy intensive industries that shift their consumption to moments of power oversupply (Paulus and Borggrefe, 2011). Residential customers can provide demand response as well (Siano, 2014) with flexibility provided by home appliances, storage, heat pumps and electric vehicles: devices that are connected to the distribution grid. However, using all the devices simultaneously could lead to a grid load being higher than the available capacity. Such a situation is called congestion and preventing it is a responsibility of the Distribution System Operator (DSO). Demand response can thus cause congestion, but flexible loads could also resolve congestion if an aggregator would decide to ramp down consumption in periods of high peak load in the local grid.

The situations described above show that flexibility is a valuable resource that needs to be shared between different stakeholders. For example, it could be used to provide balancing capacity or to manage

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congestion on the local grid. However, the uncoordinated use of flexibility in attempt to solve one problem could create a new difficulty (Zecchino et al., 2017), which has also been observed in existing pilots that investigate using flexibility for congestion management (Fonteijn et al., 2019). Since flexibility in demand is controlled by an aggregator who aims to maximize its financial value, encouraging an efficient utilization of flexibility requires a proper monetary incentive (EidPaul et al., 2016).

Those incentives are set by the entities that require flexibility. In recent years, the attention of researchers has been focused in particular on incentives to manage congestion through grid tariffs (Verzijlbergh et al., 2014). Enough evidence that grid tariffs can influence the consumption behavior can be found in the current literature (Kirkerud et al., 2016), (Schreiber et al., 2015), (Bergaentzlé et al., 2019). In most of Europe, grid tariffs are uniform across the whole country. However, congestion is a local problem. A localized approach to congestion management is a flexibility market, which considers flexibility to be a product that can be traded between the consumer and grid operators: DSOs and TSOs (Gerard et al., 2018). An alternative to such a flexibility market is a capacity market where the DSO sells the available capacity of the grid to the consumers (Philipsen et al., 2016).

Although it has been recognized that congestion can be affected by the imbalance market (Chaves-Ávila et al., 2014), (Schreiber et al., 2015), grid tariffs and local congestion markets are described in the current literature from the perspective of managing congestion and without considering the imbalance market. There is thus a research gap in explaining how participation of flexible loads in the imbalance market affects the effectiveness of Congestion Management Mechanisms (CMM) in reducing the peak load. Conversely, the influence of the CMM on the system imbalance has not been investigated. Therefore it is not known how the financial incentive from the imbalance market is competing with a congestion management mechanism, and how this affects the load. The purpose of our research is to close this gap and investigate how effective CMMs are in preventing congestion in the context of flexible loads that can cause congestion by being activated simultaneously in response to a low imbalance price.

An important contribution of this paper is evaluating network tariffs and other CMMs from the perspective of flexibility allocation between grid balancing and congestion management. This new criterion complements the ongoing investigation of grid tariffs, which are currently evaluated only with respect to fairness (Neuteleers and MulderFrank, 2017) and the policy goals, i.e., cost reflectivity, allocative efficiency, accessibility to electricity, transparency, simplicity, predictability and robustness (Nijhuis et al., 2017), (Bergaentzlé et al., 2019). Another contribution is evaluating and comparing traditional CMMs (the energy and capacity tariff) with modern ones (the flexibility market), which explains how local approach to congestion management impacts the DSO, the TSO and the manager of flexible loads. Finally, we analyse the trade-off between using flexibility for system balancing and for congestion management. Gathering such insights plays an important role in designing the congestion mechanism that maximizes the value of flexibility.

The paper is organized as follows. In the reminder of this section, we elaborate on how the aggregator's participation in the imbalance market can contribute to congestion on the local grid and what the DSO can do to prevent it. In section 2 we propose a mathematical formulation to model the aggregator's response to the imbalance market and the CMMs imposed by the DSO. We also describe an experiment which uses the proposed model to research the effectiveness of different CMMs. In section 3, we discuss the results obtained in experiments. The manuscript is concluded with policy recommendations made in section.

1.1. *The interaction between local congestion and grid balancing*

We study the methods available to the DSO to prevent the congestion that can occur because of an aggregator who manages flexible loads and responds to imbalance prices, and we evaluate these methods from the perspective of the efficiency of the whole system: the value for resolving imbalance and the success in preventing congestion.

In this section, we explain in more detail how the imbalance market works, why and how an aggregator would participate in the imbalance market, and how congestion on a local grid can be created as a result. We also discuss existing monetary incentives that the DSO can use to prevent congestion.

1.2. *The imbalance market*

Electricity cannot be efficiently stored so it is important that the power production is equal to the power consumption at all times. A TSO makes sure that this condition is fulfilled through the imbalance market by asking the participants to adjust their schedules if there is a power surplus or shortage in the grid. The final imbalance price reflects all the costs made by the TSO as a consequence of grid balancing, and it also provides information about the financial reward for the grid users that contribute to restoring the balance and a penalty for imbalance causers (Brijs et al., 2017).

Low imbalance prices provide financial incentives to increase consumption which could lead to congestion on the distribution grid, like presented in Fig. 1. The figure shows the load in the grid with electric vehicles responding to imbalance prices. We can observe many load spikes which occur when imbalance prices are very low as a result of surplus energy being injected in the power system. From the perspective of the transmission operator increasing consumption in those Program Time Units (PTUs) is a desired action. However, the load spikes create congestion in the local grid, i.e., the grid load exceeds the available capacity, marked in the graph with a horizontal line. Note that the higher the charging speed of electric vehicles is, the higher the spikes (Fig. 1).

1.3. *Congestion management mechanisms*

Congestion management mechanisms are designed to affect the consumption pattern and provide incentives to avoid grid overload. Flexible load is expected to be shifted from more to less congested moments. Several congestion management mechanisms are described in this section. First we focus on the energy tariff and capacity tariff, as these two (or a combination of them) are currently being used most often by the DSOs. Later, we discuss a modern approach to congestion management: the flexibility market.

1.3.1. *Energy tariff*

According to the concept of an energy tariff, grid users are obliged to pay for the total consumed energy. Often, the price for each MWh of consumed energy is fixed, which means that the user pays the same amount regardless of what the load in the distribution grid was at the moment of user's consumption. Such design provides incentives to consume less energy in total but no information about congested PTUs. The DSO could provide this information by varying the energy price in time, i.e., asking for a lower payment for energy consumed in PTUs with a low load in the distribution grid and a high payment for energy consumed in congested PTUs. A day – night tariff, which assumes a higher price during the day and lower price during the night, is a simple example of such a construction.

1.3.2. *Capacity tariff*

A capacity tariff assumes the payment to the DSO to be based on the maximal achieved power, providing incentives for the end user to keep the peak consumption as low as possible. A peak tariff is a variant of the capacity tariff where the payment to the DSO is the peak load caused by end user's consumption multiplied by the tariff. The tariff could be constant or depend on the size of the peak load. A discretized version of the peak tariff is a tier tariff, defined by a price and a capacity step. The

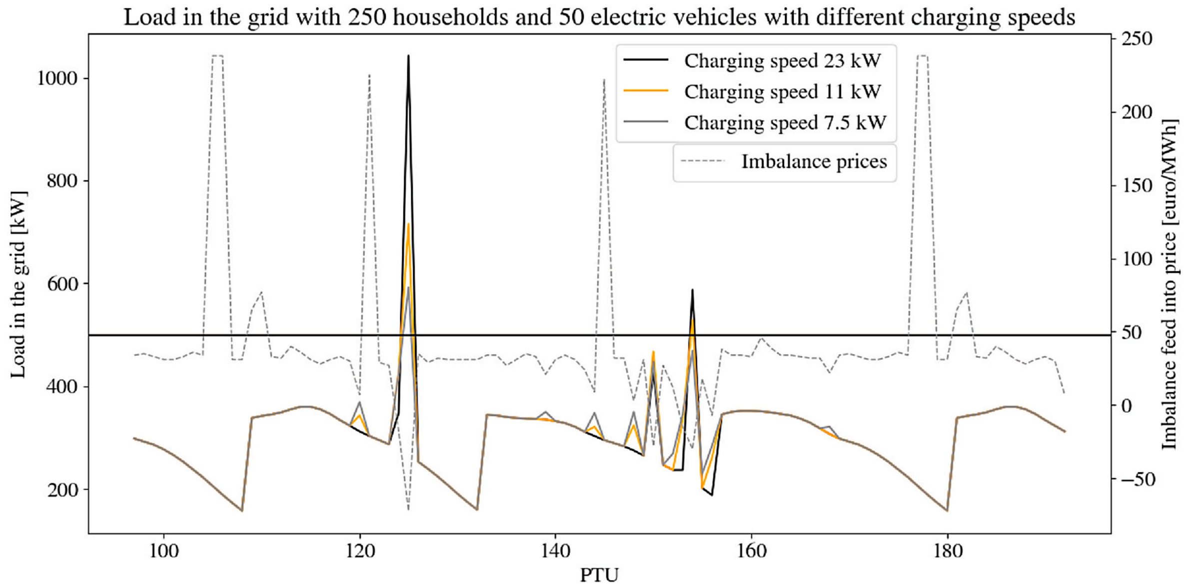

Fig. 1. Grid load in an example distribution grid with 250 households and 50 electric vehicles that respond to imbalance prices (dashed line). Line loadings are shown for three different charging speeds.

user's payment is based on a capacity class to which the peak load belongs.

1.3.3. Flexibility market

A flexibility market is a venue where flexibility in consumption is a product and can be traded both by a DSO and a TSO (Villar et al., 2018). All the grid operators trying to solve a congestion or imbalance problem and all devices with flexible consumption that could solve grid problems compete against each other in one market. Currently, existing flexibility markets are mostly in a pilot phase, as local procurement of flexibility is still a developing concept. In the following section we describe the specific type of flexibility market that is modeled in the current paper in more detail.

2. Mathematical formulation

To be able to quantitatively compare different CMMs, we need a model for the behaviour of consumers given the CMM and the market conditions. To allow for thorough analysis and interpretation of the experiments, we make a number of simplifying assumptions.

First, we assume that all consumers with flexible demand are represented by an aggregator who acts optimally on their behalf. We further assume that the (possibly negative) cost of changing the aggregator's position at a certain time is generated by only one market, which we call the imbalance market here. Further we assume these imbalance prices are known and independent of the behavior of the aggregator. These are strong assumptions, as in many countries there are multiple markets, e. g. also an intra-day market where such flexibility can be traded, and prices are typically not completely known, but we claim that this simple model of a single market provides sufficient context to evaluate different CMMs and this prevents the results being influenced by price predictions or trading strategies.

The trading of flexibility by the aggregator is done based on a position taken day-ahead. In the experiments we consider four variants of a day-ahead schedule as purchased and declared by an aggregator, further discussed in section 2.8. Below we propose the consequential mathematical optimization problems that define the minimization of the costs of an aggregator of flexible demand, for each of the different CMMs.

2.1. Centralized optimization – the most effective CMM

An efficient CMM provides incentives to avoid congestion while posing as little restrictions as possible on participating in the imbalance market. A centralized optimization abstracts this most efficient CMM. We set this as a benchmark to evaluate the performance of other CMMs.

The aggregator's objective is to minimize the cost of power consumed by the devices with flexible loads, given the day-ahead position. This cost is generated by the activity on the imbalance market. Participation in the imbalance market can happen in two ways. On the one hand, a device d can ramp down the consumption in a PTU t, relative to the day-ahead position $p_{t,d}^{\mathrm{DA}}$, which we denote by $p_{t,d}^{\mathrm{imb}^-}$. For this an aggregator receives a payment from the TSO. The imbalance price in euros per MWh for feeding in the power to the system is denoted by $\lambda_{t,\mathrm{imb}}^{+}$. On the other hand, a device can ramp up the consumption, denoted by $p_{t,d}^{\mathrm{imb}^+}$. For this the aggregator needs to pay the TSO. The imbalance price in euros per MWh for taking power from the system is denoted by $\lambda_{t,\mathrm{imb}}^{-}$. Though a participant receives money for feeding the power in, the imbalance price might be negative, in which case the cash flow is from the consumer to the grid. Similarly, the negative imbalance price reverses the cash flow for buyers of power.

The main constraint, expressed below in Eq. (2), is that the total load does not exceed the available network capacity in any of the PTUs $t \in T$. The total load consists of the sum of inflexible loads π_t and the sum of flexible loads managed by an aggregator. The total flexible load is the sum of the day ahead consumption pattern $p_{t,d}^{\mathrm{DA}}$ and imbalance adjustments up $p_{t,d}^{\mathrm{imb}^+}$ and down $-p_{t,d}^{\mathrm{imb}^-}$. The indexes t and d correspond to PTU $t \in T$ and a device with flexible load $d \in D$.

The consumption pattern needs to be feasible with technical limitations of devices providing the flexible load, which we express with the constraint 4. An example of constraints for a specific device is provided in section 4. The considerations above can be expressed in the following optimization problem:

$$\min_{p_{t,d}^{\mathrm{imb}^-},\, p_{t,d}^{\mathrm{imb}^+}} \sum_{t,d} \left(-\lambda_{t,\mathrm{imb}}^{+} p_{t,d}^{\mathrm{imb}^-} + \lambda_{t,\mathrm{imb}}^{-} p_{t,d}^{\mathrm{imb}^+} \right) \quad (1)$$

subject to:

$$\pi_t + \sum_{d \in D} \left(p_{t,d}^{\mathrm{DA}} - p_{t,d}^{\mathrm{imb}^-} + p_{t,d}^{\mathrm{imb}^+} \right) \leq \mathrm{cap} \ \forall t \in T \tag{2}$$

$$0 \leq p_{t,d}^{\mathrm{imb}^-}, p_{t,d}^{\mathrm{imb}^+} \ \forall t \in T, \forall d \in D \tag{3}$$

$$0 = f(t, x) \ \forall t \in T, \forall x \in X \tag{4}$$

2.2. Energy-based tariff

Though we know that centralized optimization is the most efficient CMM, it is just an abstraction. Below we formulate optimization problems for known CMMs. The most common tariff currently applied for residential customers in Europe is the energy tariff.

An aggregator needs to pay the energy tariff τ_t^{E} for each MWh consumed by the devices in PTU t to cover the network cost of the electricity bill. The objective function expressed below in Eq. (5) is the same as in the case of the optimal tariff with the additional component corresponding to the grid cost.

The optimization problem that the aggregator needs to solve is of the form:

$$\min_{p_{t,d}^{\mathrm{imb}^-}, p_{t,d}^{\mathrm{imb}^+}} \sum_{t,d} \left(-\lambda_{t,\mathrm{imb}}^{+} p_{t,d}^{\mathrm{imb}^-} + \lambda_{t,\mathrm{imb}}^{-} p_{t,d}^{\mathrm{imb}^+} + \tau_t^{\mathrm{E}} \left(p_{t,d}^{\mathrm{DA}} - p_{t,d}^{\mathrm{imb}^-} + p_{t,d}^{\mathrm{imb}^+} \right) \right) \tag{5}$$

subject to 3 and 4.

2.3. Peak tariff and tier tariff

The peak and tier tariff are based on the peak power consumed by the end user rather than on total consumed energy, as it is the case with the energy tariff. Therefore, the user is not charged based on how often and how much he used the gird but based on the maximal load he imposed on the grid.

The grid payment is determined by the peak load p_d^* generated by the grid user owning a device d, as expressed in the objective function 6. The network cost is equal to $\tau^{\mathrm{P}} p_d^*$ where τ^{P} is the peak tariff, expressed in euros per MW. Depending on the exact tariff design, the value of τ^{P} might depend on the value of p_d^*, forming a piece-wise linear function. We use a linear function, i.e., a constant τ^{P}, as a generalization of the peak tariff. The peak load is the maximal total consumption achieved in the accounting period by a grid user. This constraint is given by Eq. (7). The total load in each PTU is the sum of inflexible loads π_t, e.g., generated by a household, and flexible loads.

The optimization problem for the aggregator thus is of the form:

$$\min_{p_{t,d}^{\mathrm{imb}^-}, p_{t,d}^{\mathrm{imb}^+}} \sum_{t,d} \left(-\lambda_{t,\mathrm{imb}}^{+} p_{t,d}^{\mathrm{imb}^-} + \lambda_{t,\mathrm{imb}}^{-} p_{t,d}^{\mathrm{imb}^+} + \tau^{\mathrm{P}} p_d^* \right) \tag{6}$$

subject to 3, 4, and

$$\pi_t + p_{t,d}^{\mathrm{DA}} - p_{t,d}^{\mathrm{imb}^-} + p_{t,d}^{\mathrm{imb}^+} \leq p_d^* \ \forall t \in T, \forall d \in D \tag{7}$$

The tier tariff τ^{T} is a discretized version of the peak tariff. Therefore, the objective function in both cases looks the same except that the user's peak consumption p_d^* has been now replaced by the class of the peak consumption $[p_d^*]$. Constraint 9 classifies the calculated peak's capacity class depending on the step S, which is a part of tier tariff's definition.

The optimization problem is of the form:

$$\min_{p_{t,d}^{\mathrm{imb}^-}, p_{t,d}^{\mathrm{imb}^+}} \sum_{t,d} \left(-\lambda_{t,\mathrm{imb}}^{+} p_{t,d}^{\mathrm{imb}^-} + \lambda_{t,\mathrm{imb}}^{-} p_{t,d}^{\mathrm{imb}^+} + \tau^{\mathrm{T}} \left[p_d^* \right] \right) \tag{8}$$

subject to 3, 4 and

$$\frac{p_d^*}{S} \leq \left[p_d^* \right] < \frac{p_d^* + S}{S} \ \forall t \in T, \forall d \in D \tag{9}$$

2.4. Flexibility market

A flexibility market is a venue where energy flexibility can be sold as a product. Our model is based on the common elements of flexibility markets that can be found in the literature and documentation of existing pilots.

A typical feature of a flexibility market is that congestion problems are already addressed one day before delivery, based on the load forecast (MorstynAlexander and McCulloch, 2018), (Hers et al., 2016). In our model, the day-ahead load forecast is represented by the day-ahead schedules. If there is a congested PTU, the difference between the expected load and the grid capacity is the flexibility volume required to solve the problem; we denote this by $\overline{F_t}$.

Addressing congestion one day before delivery can be supported by DSOs because it creates a sense of security and control. However, an approach of rewarding market participants in response to a forecast provided by the same participants is known to be prone to gaming. A consumer could declare high demand but consumes less power than previously reported with the purpose of receiving a payment for preventing congestion, which is known as an increase – decrease game (Neuhoff et al., 2011).

The flexibility market is designed to prevent congestion, but day-ahead purchases made by the DSO are not enough to guarantee that goal. Congestion that was not predicted one day ahead can still occur on the day of power delivery, e.g., due to errors in the load forecast. Various existing pilots, such as GOPACS (Tim Schittekatte and Meeus, 2020), Interflex (Bhattacharyya et al., 2019), and Energiekoplopers (Fonteijn et al., 2019) enable intraday trading of flexibility. To model the necessary intraday interventions, as well as to ensure that the flexible consumption shifted from a congested PTU cannot cause congestion in another PTU, a constraint that ensures that the grid capacity is never exceeded is added to the model. This constraint is only applied to aggregators that, by participation in the flexibility market, have committed themselves to respecting grid constraints. An aggregator is rewarded by receiving a payment for the total volume of flexibility, sold one day ahead and intraday. To calculate the volume of flexibility required intraday, we compare the grid capacity to the consumption schedule that minimizes the cost ignoring network payments/tariffs. In the model, we assume one fixed price for flexibility, φ, which marks the minimal costs of rewarding an aggregator. In practice, this amount could be distributed differently, e.g., the price could change depending on the PTU. The binary variable x corresponds to aggregator's decision regarding participation in the flexibility market. If the aggregator did not sell flexibility and $x = 0$, Eq. (11) ensures that aggregator's position at the flexibility market is equal to zero. A big constant N in Eq. (13) relieves an aggregator from any obligations towards the DSO. On the other hand, if $x = 1$, Eq. (11) allows for selling flexibility and Eq. (13) enforces complying with the market's rules.

We model just one active aggregator. If there is more than one aggregator contributing to congestion in a certain PTU, they can compete for a flexibility price. Since we assume that all of them have perfect knowledge of imbalance prices, the fair price would be the same for all of them. Therefore, we can model all aggregators as one.

The aggregator's objective function is mostly the same in the case of the flexibility market as it is with other CMMs. However, ramping consumption down might have two reasons. On the one hand, flexibility might be used this way to be sold on the flexibility market. The amount of kWs sold in PTU t by device d on the local market is marked as $f_{t,d}$. On the other hand, an aggregator might still want to reduce consumption for balancing purposes in a situation when no flexibility is needed as there is no congestion. The amount of kWs of reduced consumption that was not sold on the local market is denoted as $p_{t,d}^{\mathrm{imb}^-}$. Notice that an aggregator is rewarded on the imbalance market only for $p_{t,d}^{\mathrm{imb}^-}$ and not for $f_{t,d}$.

Constraints 14 and 15 ensure that flexible devices are not scheduled to consume more for balancing purposes and at the same time ramp down to prevent congestion. The binary variable y ensures that the large constant M is used only in one of the two constraints. If $y = 0$ then Eq. (14) enforces $p_{t,d}^{\mathrm{imb}^+}$ to be equal zero, but Eqs. (14) and (15) do not limit $f_{t,d}$. On the other hand, when $y = 1$ Eq. (15) forces $f_{t,d} = 0$ and $p_{t,d}^{\mathrm{imb}^+}$ is not limited.

The considerations above can be expressed in the following optimization problem for the aggregator:

$$\min_{p_{t,d}^{\mathrm{imb}^-}, p_{t,d}^{\mathrm{imb}^+}, f_{t,d}} \sum_{t,d} \left(-\lambda_{t,\mathrm{imb}}^{+} p_{t,d}^{\mathrm{imb}^-} + \lambda_{t,\mathrm{imb}}^{-} p_{t,d}^{\mathrm{imb}^+} - \varphi f_{t,d} \right) \quad (10)$$

subject to 3, 4 and

$$0 \le f_{t,d} \le x P_d \; \forall t \in T \quad (11)$$

$$\sum_{d \in D} f_{t,d} \le \overline{F_t} \; \forall t \in T \quad (12)$$

$$\pi_t + \sum_{d \in D} \left(p_{t,d}^{\mathrm{DA}} - p_{t,d}^{\mathrm{imb}^-} - f_{t,d} + p_{t,d}^{\mathrm{imb}^+} \right) \le \mathrm{cap} + (1 - x) N \; \forall t \in T \quad (13)$$

$$f_{t,d} + p_{t,d}^{\mathrm{imb}^+} \le f_{t,d} + M y_{t,d} \; \forall t \in T, d \in D \quad (14)$$

$$f_{t,d} + p_{t,d}^{\mathrm{imb}^+} \le p_{t,d}^{\mathrm{imb}^+} + M \left(1 - y_{t,d} \right) \; \forall t \in T, d \in D \quad (15)$$

2.5. Case study

A set of experiments that simulate the interaction between the aggregator's response and the grid congestion mechanism are proposed in this section. In the experiments, the model is applied to the data that represent a realistic situation in the distribution grid. In the course of the experiments, we collect the load data and the information about the aggregator's revenue on the imbalance market. The data is used to evaluate how effective each CMM is in facilitating demand response and what is its distance to the centralized optimization. The investigated CMMs are energy tariffs: fixed, day night and time of use described in (Verzijlbergh et al., 2014), peak and tier tariffs increased by 100 euros/MW from 0 to 3000 euros/MW with capacity steps 0.5 kW, 1 kW, 2 kW, flexibility market with flexibility price increased by 100 euros/MW from 0 to 3000 euros/MW and the centralized optimization.

2.6. The simulated grid

In the experiments we are simulating an optimal response of an aggregator to various CMMs in a residential area that consists of 250 households, as represented in Fig. 2, supplied by one feeder with capacity 500 kW, which is an adequate capacity as the network capacity typically is enough to facilitate maximal load of 2 kW per household. Households' consumption profiles are derived from DSOs assumption, as discussed in (KlaassenJasper and Han, 2015).

2.7. Flexible consumption

Flexible loads are represented by EVs. To represent various driving patterns of EVs, we model 25 types of drivers as proposed in (Verzijlbergh et al., 2014). All the EVs have equal charging speed. The three variants of batteries' charging speed that are examined are 7.5 kW, 11 kW and 23 kW. The recent development in charging capabilities suggest that those charging speeds are a realistic representation of the future of charging EVs at home (SalahJens et al., 2015). We consider the following levels of EVs penetration: 10%, 20% and 50%. We also assume that EVs' capacity is equal to their total demand and the efficiency of 95%. Since we know the physical limitations of EVs we are able to define constraints of the optimization problems given by Eq. (4). First, the EV's consumption per PTU, equal to the sum of the day ahead schedule and imbalance deviations, cannot be higher than the charging speed, which is ensured by Eq. (16). Second, the state of charge $\omega_{t,d}$ of an EV d in a PTU t cannot be higher than the capacity $\omega_d^{\max}$ or lower than the minimal required level $\omega_d^{\min}$, as expressed by Eq. (17). Finally, we describe in Eq. (18) that a state of charge in PTU t is calculated by adding the energy consumed in PTU t multiplied by the efficiency η_d to the state of charge in PTU $t-1$ and subtracting discharged energy $x_{t,d}$.

$$0 \le p_{t,d}^{\mathrm{DA}} - p_{t,d}^{\mathrm{imb}^-} + p_{t,d}^{\mathrm{imb}^+} \le \mathrm{P}_d \; \forall t \in T, \forall d \in D \quad (16)$$

$$\omega_d^{\min} \le \omega_{t,d} \le \omega_d^{\max} \; \forall t \in T, \forall d \in D \quad (17)$$

$$\omega_{t,d} = \omega_{t-1,d} + \eta_d \left(p_{t,d}^{\mathrm{DA}} - p_{t,d}^{\mathrm{imb}^-} + p_{t,d}^{\mathrm{imb}^+} \right) \Delta t - x_{t,d} \; \forall t \in T, \forall d \in D \quad (18)$$

2.8. Trading conditions

We assume that an aggregator has full control over the EVs and its objective is to minimize the total cost of charging EVs. To simulate aggregator's trading decisions we solve optimization problems given in section 3 with historical prices of 30 random days in 2018 on the Dutch imbalance market. The TSO in the Netherlands is known to have a competition oriented approach to resolving the imbalance (Alexander and Dupont, 2005). Therefore, the Dutch imbalance market is a good representation of a mechanism where the price reflects the need for balancing capacity and serves as a real time signal to change the consumption behavior. The PTU in the Dutch system is equal to 15 min. We further assume that at the moment of optimizing the charging pattern EVs already declared day ahead schedule to the TSO. Imbalance position is any deviation from this schedule. We consider four variants of the day ahead schedule that cover the most logical choices as well as represent the most extreme day ahead variants in which congestion can be expected.

FIXED is a program in which each EV is scheduled to charge uniformly throughout all available PTUs. The fixed scenario represents the day ahead consumption pattern most desirable by the DSO. Load is uniformly distributed among all PTUs, making an efficient use of the electrical grid.

NULL means that EVs did not have any day ahead schedule and the whole charging takes place on the imbalance market.

IMMEDIATE stands for the situation where each EV is scheduled to charge immediately upon returning to the charging station. An immediate day ahead schedule addresses an important problem of a high coincidence factor which is introduced by EVs. Traditionally, the grid users perform actions independent of each other, e.g., there is no standard moment to use the washing machine. However, all the EVs are likely to be charged around the same time when the residents come back from work.

GREEDY means that the charging is scheduled in the cheapest PTUs on the day ahead market. The coincidence factor is also high in case of the greedy scenario as all the users decide to charge EVs at the same time. The decision is motivated by economical factors, while in case of the immediate scenario by convenience. Comparing both scenarios makes sense because in the case of the greedy scenario the consumption has already been shifted to the period that typically is less congested.

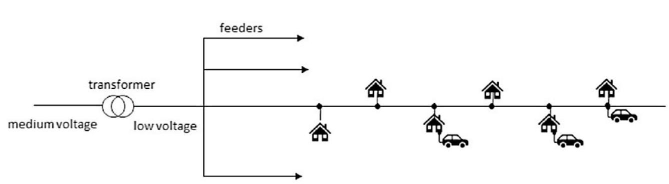

Fig. 2. The simulated grid consists of 250 households connected to one feeder with capacity 500 kW. Some of households are equipped with an electric vehicle.

2.9. Experiments setup

Each simulation run loops over 30 days in the considered dataset, solving an optimization problem for the following 96 PTUs. Such frequency is consistent with the electricity market design where the declaration of the day ahead schedule and trading of most significant volumes happens once a day, one day before delivery. However, in the proposed simulation the moment of trading decision is shifted to PTU 60, i.e., 3p.m. o 'clock. This is the time when almost all EVs are fully discharged and all available flexibility is at the aggregator's disposal.

In the course of experiments, grid load data and aggregator's revenues are measured and collected. Both values are the consequence of the adopted CMM and aggregator's decisions.

3. Results and discussion

We run the experiments explained in section 2 to compare the effectiveness of different CMMs. The most effective CMM is such that provides incentives to freely use flexibility for balancing as long as grid constraints are not violated. Such mechanism is abstracted in our model by the centralized optimization.

We collected two pieces of data to evaluate each CMM. The first measured value, the peak load, is used to establish if a CMM performed its primary task - preventing congestion. If the peak load values are below the grid capacity, which in our experiment is set to 500 kW, it means that there was no grid congestion. The second piece of data reflects the contribution of flexibility to resolving the grid imbalance which we evaluate by calculating the aggregator's revenue obtained on the imbalance market. High revenue means that flexibility was used to balance the grid in the periods of the highest mismatch between the production and consumption.

We present the results of experiments in this section. First, we compare the influence of CMMs on the load. Later, we discuss how the revenues from the imbalance market were affected by the CMM and make some remarks regarding the flexibility market. Finally we compare CMMs with each other.

3.1. The influence of CMM on the load

The first of the investigated tariffs, the energy tariff, influences the consumption pattern by varying the price in time. We considered three variants: fixed where tariff is the same for all PTUs, day night, where the tariff during nights is lower than during days, and Time of Use, where tariff is different in each PTU. The highest Time of Use tariff is assigned to the PTUs where the historical load has been the highest on average. The effects of different variants of energy tariff can be observed in Fig. 3. The energy tariff is constructed in such a way that there is a PTU in which the total price of consuming power, which is equal to the sum of the imbalance price and the energy tariff, is the lowest. Therefore, changing the energy tariff per PTU causes the peak load to shift in time. However, the tariff does not contribute to lowering the peak.

Contrary to energy tariffs, capacity tariffs base the payment to the DSO on the achieved peak consumption. Fig. 4 shows how changing the tariff affects the load in the grid. Two tariffs are shown: a tariff of 800 euro/MW, which is not high enough to prevent congestion, and a tariff of 1300 euro/MW, which is. Load spikes observed in the figure are caused by responding to imbalance prices. The spikes occur in the same moments for both tariffs. However, in case of the higher tariff they are smaller than in case of the lower tariff. Reduction of the peak consumption is an effect of the construction of the peak tariff. The consumer's payment to the DSO increases if either the tariff or the peak consumption becomes higher. A tariff of 1300 euro/MW is higher than 800 euro/MW so the consumer's payment to the DSO is also going to be higher, unless the peak consumption is reduced. To reduce the peak, some consumption needs to be shifted from PTUs with lower prices to PTUs with higher prices. The consumer decides to shift the flexible load to more expensive PTUs if the resulting increase of the cost of purchasing energy is recovered by the reduction of the payment to the DSO. If the peak tariff is very high, rather than causing a significant peak in one PTU, a consumer has an incentive to consume little energy in every PTU, as this is the only way to minimize the peak consumption and hence the payment to the DSO. In case of the tier tariff, incentives to lower the load per PTU are also provided by lowering the capacity step, as presented in Fig. 5.

The flexibility market provides a different kind of incentive. Rather than being punished with a high payment for causing high peaks, the consumer gets rewarded for changing the previously assumed consumption schedule if congestion is expected. Like we already explained, shifting load from less to more expensive PTU generates additional costs for a consumer. Reward from flexibility market should be at least high enough to make up for increase in costs. If it is not, the consumer will not have enough incentives to participate in the flexibility market and

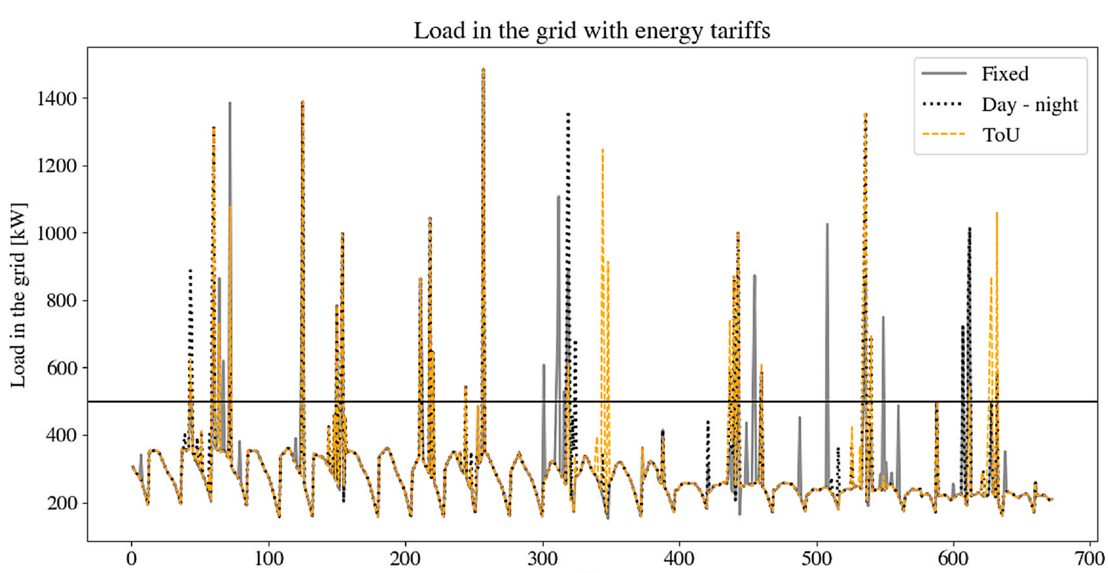

Fig. 3. Grid load obtained in an experiment with energy tariffs: fixed, day-night and time of use. The grid capacity is equal to 500 kW and marked with the horizontal black line.

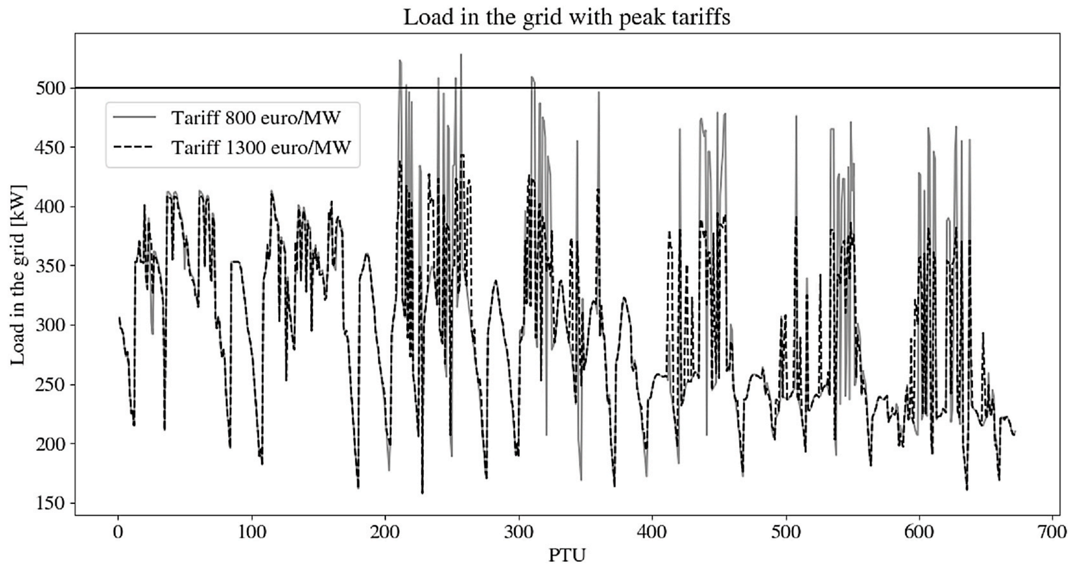

Fig. 4. Grid load obtained in an experiment with peak tariffs: 800 euro/MW and 1300 euro/MW. The grid capacity is equal to 500 kW and marked with the horizontal black line.

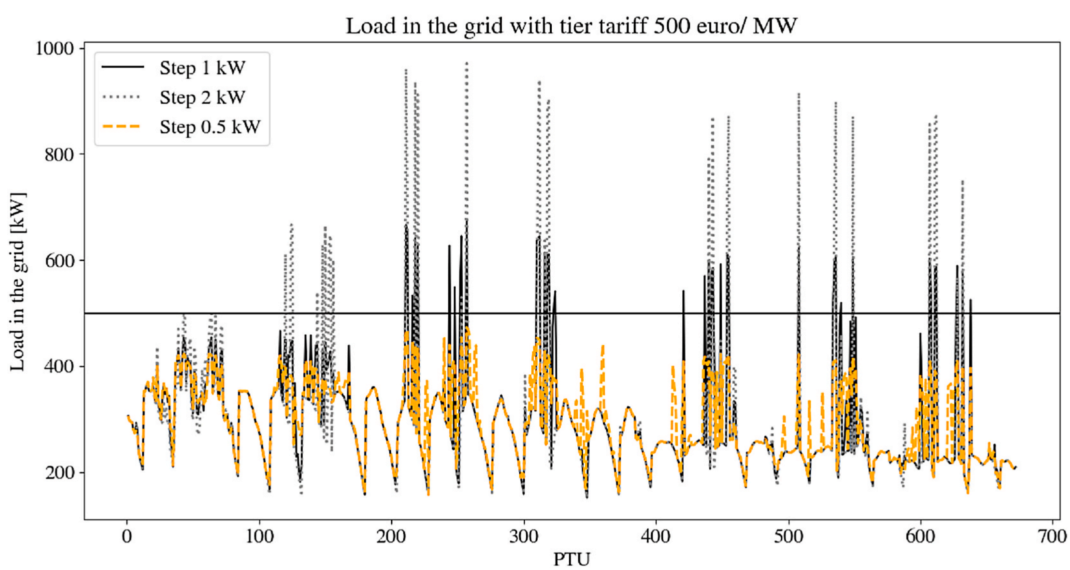

Fig. 5. Grid load obtained in an experiment with tier tariff 500 euro/MW and different capacity steps: 0.5 kW, 1 kW and 2 kW. The grid capacity is equal to 500 kW and marked with the horizontal black line.

therefore problems with congestion will not be solved. However, with the right reward flexibility loads are allocated in the most efficient way, i.e., exactly the same as in case of centralized optimization, as presented in Fig. 6.

An overview of peak load for all assumed variants of CMM, charging speed, penetration and day ahead schedules is presented in Fig. 7.

Rows of the figure represent different day ahead schedules and columns correspond to different CMMs. Each graph plots the relation between a tariff and the peak load. Every line represents a combination of charging speed and level of penetration of EVs. The first column of Fig. 7 presents peak load corresponding to energy tariff and shows that for the energy tariff, the peak load exceeds the grid capacity for all investigated configurations of the day ahead schedule, EVs penetration and charging speed. Therefore, energy tariff is not an effective CMM. The second and third column of Fig. 7 correspond to capacity tariffs. It can be observed that there is a tariff high enough to prevent congestion. The fourth column of Fig. 7 corresponds to flexibility market. The value on x axes is the flexibility price which is the price that the DSO is willing to pay to the consumer for each MWh of shifted consumption. It can be observed that if the flexibility price is too low, the consumer does not participate in the flexibility market and there is congestion in the grid. However, if the flexibility price is high enough, the grid congestion is resolved.

We were able to identify which of the investigated CMMs can prevent congestion by analyzing the columns of Fig. 7. By comparing the rows we observe that the day ahead schedule does not have an influence on the peak load in the grid. The explanation of this situation is provided by Fig. 8. The figure shows that the charging pattern is always the same despite the declared day ahead schedule. If a consumer committed to consuming energy in a given PTU and did not follow through with it, he is actually delivering energy to the power system for which he receives a payment, dependent on the imbalance price. On the other hand, if a consumer did not commit to consuming energy but did it anyway, he is taking energy from the system, for which he needs to pay the imbalance price. Consuming energy in the PTUs with the lowest imbalance prices

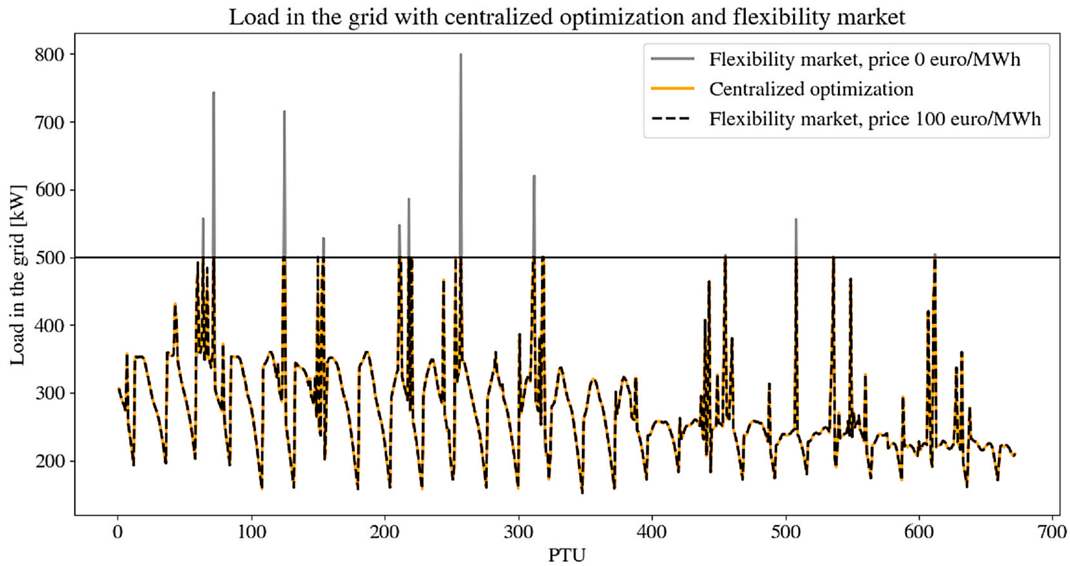

Fig. 6. Grid load obtained in an experiment with centralized optimization and flexibility market with prices 0 euro/MWh and 100 euro/MWh. The grid capacity is equal to 500 kW and marked with the horizontal black line.

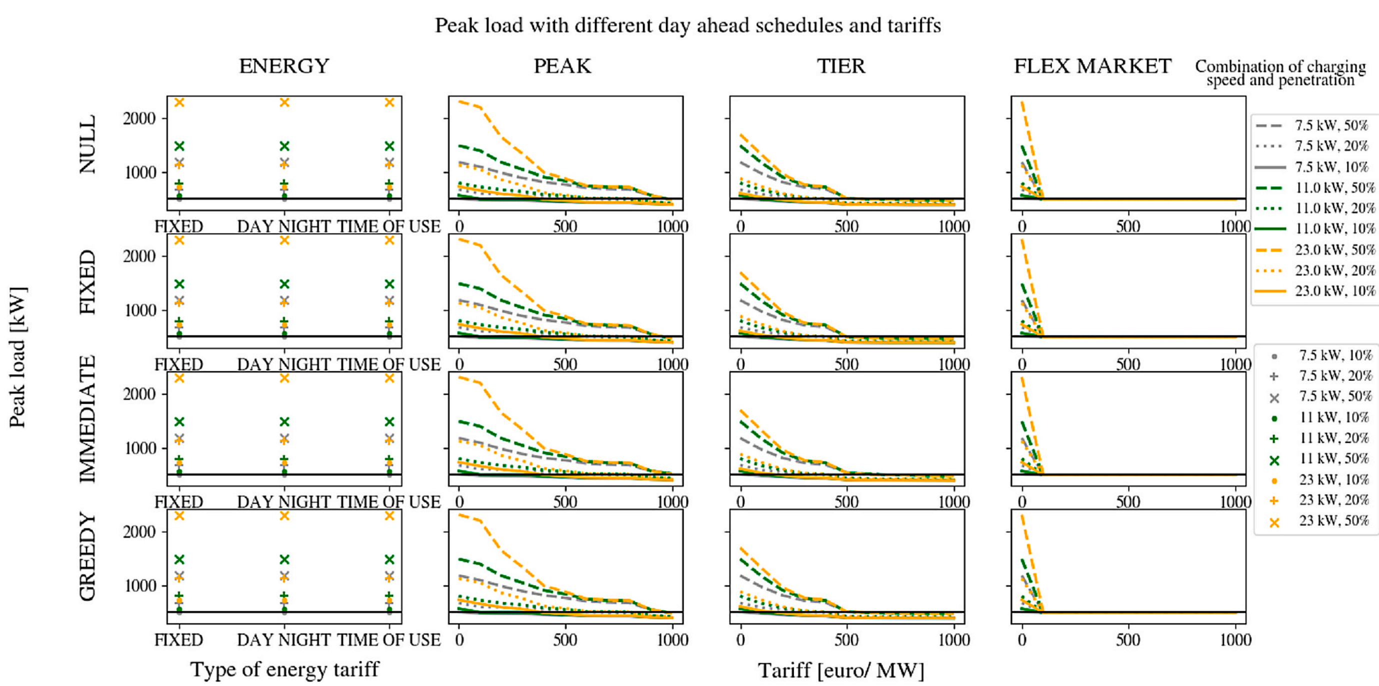

Fig. 7. Comparison of grid load obtained in experiments with different parameters settings. Rows correspond to day ahead schedules, columns correspond to CMMs and each line represents a different combination of charging speed and penetration. The grid capacity is equal to 500 kW and marked in each graph with the horizontal black line.

instead of in PTUs declared in the day ahead schedule is therefore always more beneficial than executing the day ahead schedule.

3.2. The influence of CMM on participation in the imbalance market

The second criterion used to evaluate the effectiveness of a CMM is the revenue achieved by an aggregator on the imbalance market, which is measured to reflect if flexibility was used for balancing when most needed. An overview of the collected results is presented in Fig. 9. The columns of the figure correspond to different CMMs, the rows to different day ahead schedules and every line represents a combination of charging speed and level of penetration of EVs. To understand what is presented in the graphs, we recall that the most effective CMM has been abstracted in our research by the centralized optimization. The revenue obtained by an aggregator on the imbalance market is the maximal revenue possible to achieve without violating grid constraints. We use this revenue as a benchmark to compare with revenues from the imbalance market obtained when an aggregator had to respond to different CMMs. The graphs plot the difference between the two. A positive number means that an aggregator could have contributed more to resolving the imbalance without violating grid constraints. A negative number suggests that an aggregator could have obtained revenues even higher than our benchmark. However, achieving this revenue would require to exceed the grid's capacity.

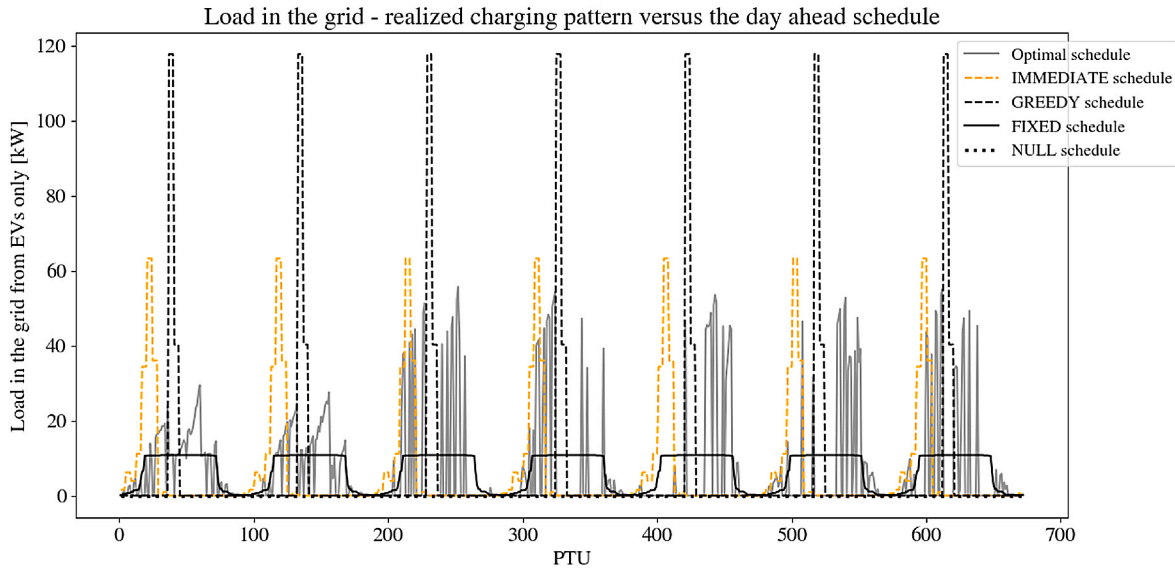

Fig. 8. Comparison of grid load according to declared day ahead schedules and the real time optimal charging pattern.

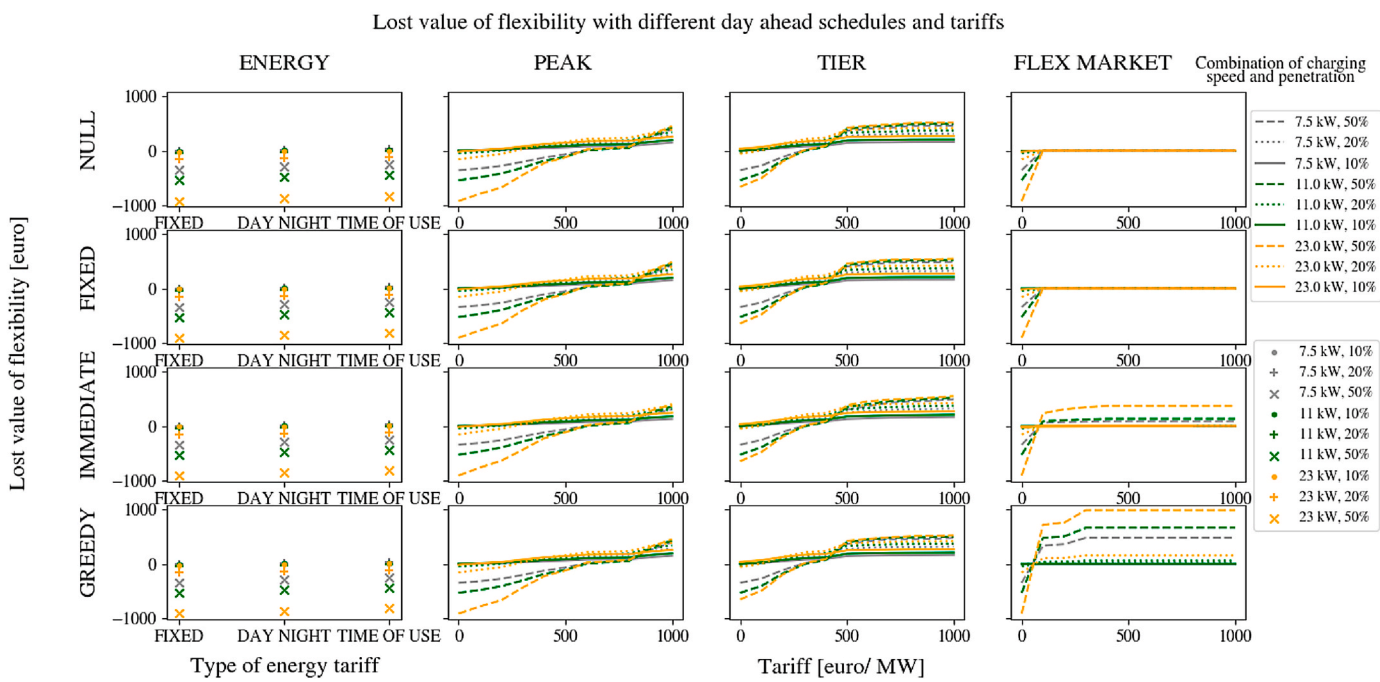

Fig. 9. Comparison of lost value of flexibility obtained in experiments with different parameters settings. Rows correspond to day ahead schedules, columns correspond to CMMs and each line represents a different combination of charging speed and penetration. The lost value of flexibility is the difference between revenues from the imbalance market in case of the centralized optimization and the applied CMM.

The first column of Fig. 9 suggests that, when energy tariff is the applied CMM, an aggregator could obtain revenues even higher than the benchmark. However, as already shown in Fig. 7, the energy tariff does not prevent congestion. The second column of Fig. 9 corresponds to a peak tariff. As the tariff becomes higher, the aggregator's revenues decrease. This means that on one hand the peak tariff has to be high enough to prevent congestion, but on the other hand if a peak tariff is too high it reduces the value of flexibility on the imbalance market.

We observe that for the energy tariff, peak tariff and tier tariff the day ahead schedule does not affect the lost value of flexibility. However, in case of flexibility market, represented in the fourth column of Fig. 9, the day ahead schedule has a significant influence on the lost value of flexibility. If an aggregator did not declare any day ahead position, flexibility market contributes to the full realization of flexibility's value on the imbalance market. However, in case of the greedy day ahead schedule (arguably a more common situation), participation in the flexibility market significantly reduces the value of flexibility in the imbalance market.

3.3. *Trading on the flexibility market one day before delivery*

Fig. 10 explains this loss of value of flexibility when using the flexibility market. Participation in the flexibility market one day before delivery changes the day-ahead schedule of an aggregator (from black to green), reducing the planned consumption around PTU 40, and thereby the aggregator loses an option to deliver this extra power to the

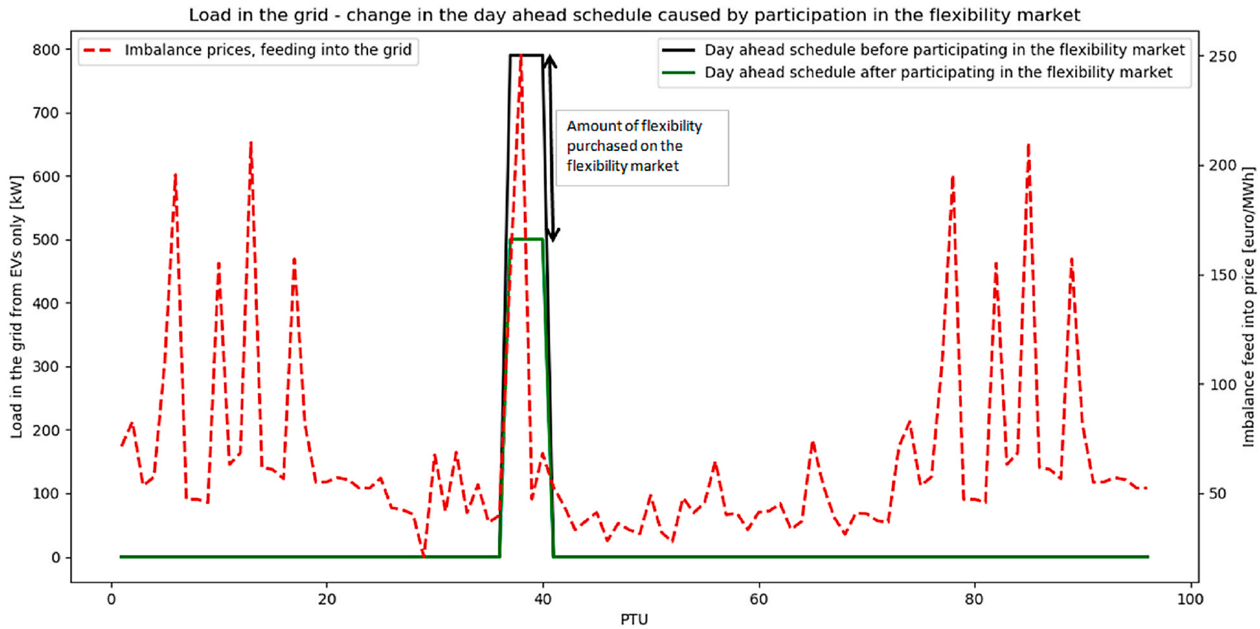

Fig. 10. Participation in the flexibility market reduces the amount of flexibility that can be used in the imbalance market.

imbalance market (at a good price).

This example shows that the day-ahead schedule changes in response to the flexibility market. It is natural to ask how much flexibility that was actually needed to resolve congestion was purchased on flexibility market one day before delivery. The answer is presented in Table 1. It can be observed that though in certain cases as much as 16,617 kW h of flexibility have been purchased one day ahead, only 273 kW h of that volume was actually needed.

3.4. Comparison the effectiveness of investigated CMMs

We explained how the CMM influences the load in the grid and consumer's participation in the imbalance market. With the obtained information, we are able to compare the effectiveness of investigated CMMs. We can identify the tariff high enough to prevent congestion by plotting the peak load against the tariff, like in Fig. 7. Fig. 11 shows the lost value of flexibility for the lowest tariff, or flexibility price in case of flexibility market, that ensures no congestion. In other words, the figure presents the most effective version of each CMM. The value on the x axis of Fig. 11 marks the lowest tariff that had to be applied to ensure no congestion. The y axis is the corresponding lost value of flexibility. Symbols in the figure mark different CMMs and colors represent charging speeds. We show only the two most extreme day-ahead schedules and the highest investigated penetration of 50%.

Since all the points presented in Fig. 11 are sufficient to prevent congestion, we can consider the points with y coordinate closer to 0, so the ones with lower lost value of flexibility, to be more effective. Notice that despite the charging speed, tier tariff with capacity step 0.5 kW is always less effective than the peak tariff which in turn is less effective than tier tariff with capacity step 1 kW. Tier tariff with capacity step 1 kW is as effective as tier tariff with capacity step 2 kW, although capacity step 2 kW requires about twice as high tariff as capacity step 1 kW to prevent congestion. However, performance of flexibility market depends on the day ahead schedule. With the null day ahead schedule, flexibility market is a more effective CMM than all the tariffs. However, if an aggregator declared a greedy day-ahead schedule, the flexibility market becomes one of the least effective solutions, depending on the charging speed.

4. Conclusions and policy implications

We studied the effectiveness of various CMMs by evaluating two metrics: the ability to prevent congestion and the value of flexibility on the imbalance market. The comparison revealed that the energy tariff is not suited to prevent grid congestion, but the peak tariff, the tier tariff and the flexibility market can provide sufficient incentives to prevent

Table 1
For different variants of the day ahead schedule, charging speeds and EV's penetration, the table shows how much flexibility was required to avoid congestion and which portion of that volume was available on the flexibility market already one day before delivery. The table also shows how much of that available volume was purchased by the DSO and what was the total volume of DSO's purchases on the flexibility market one day before delivery.

Day ahead schedule	Charging speed	EV's penetration	Total volume of required flexibility [kWh]	Volume of required flexibility available day ahead [kWh]	Volume of required flexibility purchased day ahead [kWh]	Total volume of flexibility purchased day ahead [kWh]
Immediate	7.5	50%	7495	300	207	1816
Immediate	11	50%	10,892	314	202	2640
Immediate	23	20%	3576	0	0	124
Immediate	23	50%	16,831	552	356	7232
Greedy	7.5	20%	331	0	0	372
Greedy	7.5	50%	7569	391	244	7944
Greedy	11	20%	1148	0	0	853
Greedy	11	50%	10,956	482	296	11,116
Greedy	23	10%	565	0	0	110
Greedy	23	20%	3579	2	2	2402
Greedy	23	50%	16,813	513	273	16,617

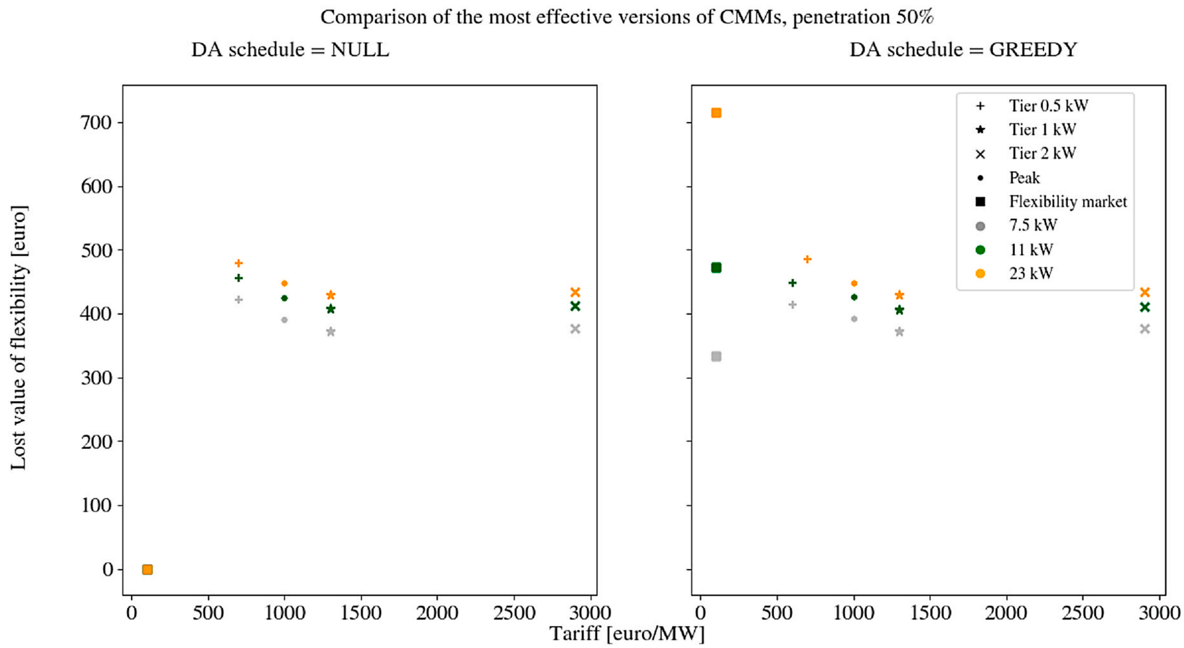

Fig. 11. Comparison of the best version of each CMM, i.e., the lowest tariff that is enough to prevent congestion. Different CMMs are marked with symbols and different charging speeds with colors. The x axis represents the tariff's value and the y axis the corresponding lost value of flexibility. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

the grid congestion. However, none of the researched CMMs turned out to be the most effective under all circumstances. Both peak and tier tariffs have on the one hand to be high enough to prevent congestion but on the other hand, such a high tariff reduces incentives for an aggregator to participate in the imbalance market. As a result, there is a significant loss of the value of flexibility in the imbalance market. In that respect, the tier tariff is less restrictive than the peak tariff. Therefore, we suggest to the DSOs that decide to introduce a tariff based on power to choose the tier tariff over the peak tariff. Special attention has to be given to how high the tariff is depending on the volume of available flexible loads.

The flexibility market outperformed other CMMs when aggregators have no or a fixed day-ahead schedule. In these cases it was sufficient to prevent congestion and in addition it allowed an aggregator to achieve almost all value on the flexibility market. However, the performance of the flexibility market declines significantly in cases when a lot of flexibility is sold already one day before delivery. If an aggregator commits to reducing the consumption, he loses the possibility of using this flexibility on the imbalance market.

Moreover, the flexibility market has some misplaced incentives. An aggregator is encouraged to declare willingness to consume power in the most congested PTUs because he could be rewarded for changing the schedule on the flexibility market. Additionally, selling power to the flexibility market means that an aggregator has to give up potential profit on the imbalance market. Hence, the DSO has to set the flexibility price high enough to compete with the imbalance market while in fact it could be that both the DSO and the TSO desire the same behavior from the consumer. Effectively, the DSO and the TSO both have to pay twice for a single solution, generating a cost which is higher than necessary. Concluding, all investigated CMMs have advantages but also flaws. To arrive at a CMM that strikes a good balance between supporting the prevention of congestion and the use of flexible demand for balancing, this analysis should be extended by considering alternative CMMs, like capacity markets, dynamic tariffs or a new bundle type of tariff that has been proposed by Dutch DSOs (Bjørndalen and Heer, 2019). The bundle tariff allows consumers to subscribe for a capacity bandwidth, for which a fixed fee is requested. If the consumer's peak consumption exceeds the allowed bandwidth, an additional payment is requested, which is dependent both on the energy and power consumed outside the bandwidth. Based on the results of our analysis, it could be expected that such CMM would leave a lot of freedom for a consumer to operate in the imbalance market within the allowed bandwidth and consuming outside of bandwidth would occur only incidentally in case of extreme imbalance prices, for short periods of time.

CRediT authorship contribution statement

Anna Stawska: Conceptualization, Methodology, Software, Formal analysis, Writing - original draft, Visualization. **Natalia Romero:** Conceptualization, Methodology, Resources, Writing - review & editing, Project administration. **Mathijs de Weerdt:** Conceptualization, Methodology, Resources, Writing - review & editing, Supervision. **Remco Verzijlbergh:** Writing - review & editing, Supervision, Visualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A. List of symbols

$t \in T$	Index of PTU
$d \in D$	Index of a device
$p_{t,d}^{\mathrm{DA}}$	Position taken by an aggregator on the day ahead market to cover consumption of device d in PTU t
$p_{t,d}^{\mathrm{imb}^-}$	Energy sold by an aggregator to the imbalance market by decreasing consumption of device d in PTU t
$p_{t,d}^{\mathrm{imb}^+}$	Energy bought by an aggregator from the imbalance market by increasing consumption of device d in PTU t
$f_{t,d}$	Position taken by an aggregator on the imbalance market by reducing consumption of device d in PTU t
$\lambda_{t,\mathrm{imb}}^{+}$, $\lambda_{t,\mathrm{imb}}^{-}$	Imbalance price for feeding in power and consuming power, respectively
φ	Price of flexibility on the flexibility market
τ_t^{E}	Network energy tariff applicable to PTU t
τ^{P}	Network peak tariff
τ^{T}	Network tier tariff
p_d^*	Peak consumption of device d
$[p_d^*]$	Class of the peak consumption of device d
cap	Grid capacity
P_d	Consumption rate of device d
$\overline{F_t}$	The total flexibility required by the DSO from the flexibility market in PTU t
S	Capacity step associated with tier tariff
$\omega_{t,d}$	State of charge of vehicle d in PTU t
$\omega_d^{\min}$, $\omega_d^{\max}$	Minimal and maximal allowed state of charge of vehicle d
π_t	Inflexible load in PTU t
η_d	Efficiency of the battery of vehicle d
Δt	Time between t and t-1
$x_{t,d}$	Energy discharged by the battery of vehicle d in PTU t

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