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Designing a local flexibility market for buying back capacity from electricity consumers connected to the distribution network

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ABSTRACT

The proliferation of flexible resources in the electric distribution network and their active management have already started to cause congestion problems, mainly in areas with significant electric vehicle penetration. In this work, we study the reduction of usable capacity as a congestion management measure in a local flexibility market context. Using an extensive two-year residential charging dataset from Denmark, we highlight the problems caused by the almost 50% non-utilized capacity on an aggregated level of household chargers. We discuss and address various market design challenges and the implications of free excess capacity by treating aggregated capacity as a divisible good that can be traded between a distribution system operator (DSO) and flexibility service providers. The use of *capacity blocks* streamlines service delivery and overcomes many of the challenges of using explicit services. Finally, we show empirically that a simple, uniform pricing, two-stage auction significantly reduces DSO payments and mitigates the issue of excessive profit margins compared to a single-stage auction.

1. Introduction

The European Union aims towards carbon neutrality by 2050 (*European Climate Law* (European Commission, 2024)), leading to a steady expansion of renewables and an accelerated electrification of the transportation sector. Distribution networks (DNs) now face the challenge of incorporating large numbers of distributed energy resources (DERs) within a short timeframe. On the one hand, DER flexibility can help reduce owner energy costs by participating in the wholesale and ancillary service markets (Rai et al., 2022; Zepter et al., 2019). On the other hand, these actions may lead to load synchronization and eventually congestion in DNs, which were not designed to accommodate substantial coincidence factors (Gunkel et al., 2023; Angelim and Affonso, 2023).

Such concerns have been acknowledged by energy regulators, distribution system operators (DSOs), and researchers, leading to numerous studies on DN-level congestion management mechanisms. The aforementioned mechanisms can be broadly categorized into rule-based measures, variable network tariffs, connection agreements, and market-based procurement via local flexibility markets (LFMs). Market-based solutions are favored by EU legislators (Chondrogiannis et al., 2022; The European Parliament and the Council of the European Union, 2019b,a) because they can promote competition and increase the efficiency of electricity systems. LFMs allow DSOs to access flexibility in the form of services and mitigate network congestion (Anaya and Pollitt, 2021; Jin et al., 2020).[1]

Flexibility service providers (FSPs) control aggregations of flexible assets (such as electric vehicle (EV) charging points or commercial buildings) and can utilize their flexibility in the wholesale and ancillary service markets. The recent surge in electricity prices, coupled with the widespread adoption of more advanced information and communication technology infrastructure, has increased electricity consumer interest towards electricity cost minimization against hourly-variable electricity prices, while more advanced business cases are emerging, such as offering ancillary services to the transmission system operator (TSO) (Lunde et al., 2024). At the same time, FSPs can offer services to DSOs via an LFM as an additional revenue stream. DSOs can utilize these services as a complementary solution to network reinforcement, leading to increased social welfare.

Despite the extensive literature on LFMs, significant gaps remain concerning trading services from both policy and market perspectives. The most severe is the need to use actual data to model the provision of DER flexibility. Without such data and the realistic simulation of

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[1] LFMs can also be used for trading services at the transmission level, but this work focuses exclusively on their use in distribution networks.

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flexibility provision, crucial aspects related to FSP opportunity costs when offering services and the impact this cost structure has on market clearing are often overlooked. To this end, we use a recent two-year dataset of EV charging patterns from residential Danish customers and show that approximately 50% of their technical capacity remains non-utilized on an aggregated level. In the remainder of the paper, we focus on the flexibility of EVs because they have the greatest potential among sources connected to the DN. However, the investigated solutions are applicable to all flexible loads. The large non-utilized EV power capacity implies that customers collectively assign a zero valuation to the unused portion or, in economic terms, the opportunity cost of foregoing the right to use this capacity is negligible. The implications are relevant to the trading of DSO services, which we discuss in detail. As a prelude, the emergent peculiarity of the LFM is similar to the one recently experienced in wholesale markets where zero marginal cost renewables meet the largest share of demand and yet prices escalate, since it is only the marginal generator that determines the price, leading to enormous profit margins for the vast majority of market players which will eventually be paid out by consumers.[2]

Another important challenge for LFM deployment is the diverse nature of DSO flexibility needs, which leads to a complex nexus of different products/services, thus compromising market liquidity and simplicity (Attar et al., 2022). This situation makes the LFM a fragmented market, severely limiting its effectiveness and hindering market participation and seamless integration with other markets (Rebenaque et al., 2023). Towards remedying this challenge, we introduce the concept of *capacity blocks*, akin to the packetized energy concept (Duffaut Espinosa and Almassalkhi, 2020; Duffaut Espinosa et al., 2018), as a simple homogeneous product that can be used to trade capacity restrictions over varying lead times and among market participants, effectively eliminating issues of market fragmentation, participation complexity, and discriminatory pricing.

In the face of the above challenges, in this paper we consider the DSO's objective of reliably procuring services necessary for the network's safe operation via an LFM that maintains the requirements for simplicity and liquidity. We propose a two-stage auction based on uniform pricing, and we empirically demonstrate that it enables the DSO to safely operate the distribution system with significantly reduced costs compared to a plain single-stage LFM design. The main contributions of this work can be summarized as follows:

- We propose an LFM design based on capacity blocks, which allows for continuous adjustment of flexible units' usable capacity in a seamless and straightforward manner, avoiding the complications introduced by trading explicit services.
- We explore and discuss the actual cost of offering capacity limitation services, and highlight the effect of zero-opportunity-cost excess aggregated capacity.
- In light of excess capacity, we explore different market design options and show that a simple, uniform pricing, two-stage auction significantly reduces DSO payments and mitigates the issue of excessive profit margins compared to a single auction with or without mandatory elimination of excess capacity.

The paper is structured as follows. Section 2 discusses key market design options and reviews existing literature on market clearing of capacity limitation services (CLSs). Section 3 presents the problem description and the proposed market solution. Section 4 introduces the case study setup, while Section 5 presents the results. Finally, Section 6 discusses crucial market aspects and describes potential future considerations, while Section 7 concludes this work.

[2] Note that this inefficiency issue is inherited (and may even be more pronounced) in pay-as-bid auction formats often adopted in flexibility markets because the market outcome of the pay-as-bid scheme is the same (in the limit) or less efficient than the one of the pay-as-clear scheme (see Tierney et al. (2008) for more details on this).

2. Market design options and literature review

2.1. Market design options

Before reviewing existing proposals regarding market clearing mechanisms, we address a few crucial market design options to frame our proposed solution. When imposing capacity restrictions, design proposals span from FSPs competing for network capacity (Morell-Dameto et al., 2024) to interruptible connections and static capacity subscriptions (Hennig et al., 2024; Bjarghov et al., 2022). This work focuses on CLSs traded in an LFM to foster competition and maximize social welfare. We exclude the study of network users competing for capacity because auctioning usable capacity leads to a situation where a DSO profits when capacity is scarcer. Instead, we envision an LFM where services are seen as a complementary measure to network reinforcement, and from that perspective, the cost of acquiring services acts as a trigger for network upgrades. Lastly, several sources point at complexity and intricate design as major barriers to LFM participation (Palm et al., 2023), stressing the need for simple designs which limit a provider's uncertainty to its domain and not externalities (also recognized in Qi et al. (2024)), such as the use of baselines or unknown activations, as discussed below.

Traded services in DN-level LFMs can be broadly categorized as *baseline* services and *capacity limitation* services (Ziras et al., 2021). The former rely on power deviations from established baselines, and the latter impose limits on the consumed power. Baselines services (BLSs) have the advantage of relatively straightforward market procurement with deliveries and compensation similar to the balancing market. However, they face challenges and uncertainties stemming from establishing transparent, easy-to-implement, and manipulation-proof baselines that all involved parties would be willing to accept (Chondrogiannis et al., 2022; Hennig et al., 2022), especially over long horizons. In Ziras et al. (2021), four service requirements were established, stating that services should be simple and transparent, encourage the use of flexibility across all markets, not be prone to manipulation, and be compatible with the continuous operation and control of flexible resources. Establishing "typical" or "expected" behavior for DERs to create baselines has been particularly challenging, especially when the flexibility of such units is used across numerous markets. These drawbacks have been analyzed theoretically (Ziras et al., 2021) and shown in research projects (Heinrich et al., 2020; Project LEO, 2024a). Indicatively, the Baselining Working Group of project LEO conducted trials for a baseline-based LFM and encountered numerous challenges, concluding with the following statement (Project LEO, 2024b): "In general, the baselining processes were seen by market participants as complicated and not transparent. Alternative flexibility markets that do not rely so heavily on baselining for verification, such as firm capacity markets, should be explored as an alternative". Additionally, since service provision is closely linked with each provider's baseline, such services cannot be easily traded among providers, and thus, a baseline service cannot be used as a homogeneous product. As a result, we limit our investigation to CLSs.

Another important design characteristic is whether services are always activated, or are reserved and activated only upon the DSO's request. Some proposals, such as Mirzaei Alavijeh et al. (2024), suggest using a reservation/activation setup where FSPs receive a reservation price and a payment every time the DSO activates the service. However, reservation payments have been described as controversial (see Schittekatte and Meeus (2020)), and here we argue against the use of a reservation/activation setup for the following reasons:

- Given the uncertainty in service activation, the expected actual costs and revenue for the FSPs would be subject to substantial uncertainty, as would payments from the DSO side; activation fees also incentivize FSPs to cause network overloadings to force activations and their subsequent payments.

- The DSO would require a tailored decision-making process and high network observability to activate services per FSP during operation, especially given the different cost of each activation.
- Market clearing should accommodate both reservation and activation prices under an uncertain activation number/volume.
- Trading services for the same period at different lead times (which is desired to mitigate inefficiencies caused by greater uncertainties over longer horizons (Hennig et al., 2023)) becomes overly complicated.
- Given the large share of non-utilized aggregated capacity (which is the case for residential EV chargers as we show with our empirical investigation), paying activation fees becomes problematic because a large part of the activation would be compensated but has no impact on network loading.
- It does not allow for the trade of capacity among FSPs.
- If the activation fee is unilaterally set by the DSO, the basic principle of individual rationality can be violated, i.e., users may find themselves forced to participate in a mechanism they deem non-beneficial.

For these reasons, and to promote a more straightforward operation of the market, which removes a large part of the uncertainty in evaluating the cost and benefit of selling and buying back capacity, we only consider scheduled services which are always activated throughout the service period.

Another relevant yet often overlooked aspect of trading CLSs is the potential heterogeneous nature of the traded good, as discussed in Mirzaei Alavijeh et al. (2024). Further, while demand or supply is associated with continuous cost or valuation functions in practice, a real-world LFM would operate under discrete and ideally not mutually exclusive offers from FSPs (Rosen and Madlener, 2013). Considering the benefits of employing a homogeneous tradable good to tackle congestion, in Section 3, we propose using capacity blocks with the DN capacity seen as a divisible good.

2.2. Review of market clearing mechanisms

Mirzaei Alavijeh et al. (2024) identify and discuss common challenges in the design of a capacity-based LFM. However, the proposed market design includes three diverse auction stages, with FSPs required to submit offers with both reservation and activation prices, constituting a complex LFM setup with significant effort required from the FSP for a potentially relatively low return. The problems of the existence of both parts were discussed in the previous section; additionally, an automated negotiation baseline for the non-utilized FSP capacities is included, further complicating the operation of the market. Lastly, only a qualitative case study is presented, which does not allow for a realistic design assessment over a long period. The authors suggest using pay-as-bid with an arbitrarily set profit margin, and more importantly, a fixed price for the non-utilized capacity.

We previously proposed a single-sided Vickrey-Clarke-Groves (VCG) mechanism to ensure the truthful reporting of FSP cost curves when providing CLSs (Heinrich et al., 2021). The major shortcoming of employing this approach is that market clearing requires the sequential removal of each FSP, necessitating an assumption of its behavior when not participating in the market. Further, if a dominant FSP is present in the network, clearing becomes impossible when removing it. Additionally, the procured services are FSP-specific, and both services and payments depend on the origin, making the product non-homogeneous.

Hennig et al. (2024) investigate the use of day-ahead CLSs, as envisioned by the Dutch regulator. The maximal capacity of the connection and allowable reduction, the price per kW of reduction, and the number of times it can be activated are mentioned as contract specifications. At the day-ahead stage, the DSO announces a reduction factor that reduces usable capacity. While this approach tackles congestion using CLSs, it is not done in a competitive market environment. Further, the authors only employ a two-week period in their case study and do not discuss the fundamental problem of aggregated non-utilized capacity, because they examine the case of individual user capacity reduction.

Several papers also propose iterative schemes where FSPs and the DSO interact in a so-called LFM (see Talari et al. (2024)) to establish network-secure schedules, usually via dual-decomposition-based algorithms. However, this way of procuring flexibility requires a very active role of the DSO and does not meet the typical operator requirements for longer-term guarantees and simplicity.

3. Proposed market design

3.1. Problem description

In most European countries (as in Denmark), each new customer connected to the DN purchases network capacity from the DSO. Typical residential consumers in Denmark are supplied with 25 A per phase, totaling approximately 17 kW per residential customer.[3] These connections for 200 residential customers lead to a total installed capacity of 3400 kW. However, the actual aggregated maximum hourly loading on this aggregation level has historically been low, leading to a peak consumption of around 250 kW for such residential customers (Dansk Energi, 2021) and a typical transformer of 660 kVA supplying them.

It has thus been common practice for DSOs to sell capacity that greatly exceeds the corresponding secondary substation's nominal value, relying on the historically proven low synchronization rates. However, EV adoption is growing rapidly in Denmark, where more than 30% of all newly registered vehicles in 2023 were all-electric and 10% plug-in hybrid (Statistics Denmark, 2024). The large-scale installation of EV chargers on the premises of residential customers and the cost-optimal charging may lead to a quick increase in transformer peak loading due to increased electricity consumption and high synchronization. This substantial EV penetration could lead to *structural congestion* (Hennig et al., 2023; Unterluggauer et al., 2023), i.e., regular congestion that can be largely predicted.

In the face of such danger, a mitigation measure foreseen by DSOs (see e.g., Rodriguez et al. (2022)) is to temporarily buy back part of the users' connection capacity to ensure that their joint power consumption profile is feasible to accommodate. In this context, two questions naturally emerge:

1. What is the user capacity cost based on current EV charging data?
2. How can a mechanism for buying capacity back from users be set up?

For illustrative purposes, we use an example of 200 chargers assigned to three FSPs in the remainder of the paper. An overview of the setup with the sold and utilized capacity is shown in Fig. 1.

Fig. 2 shows key load metrics (maximum, 99th and 95th percentiles) to assess the utilized capacity. Values are depicted monthly over two years for an aggregation of 200 chargers scheduled for cost minimization against total electricity prices. The maximum load of the aggregation reaches approximately 50% of the total capacity; the same value is also observed on an individual FSP basis. This low utilization means that the respective cost of reducing an FSP's capacity by 50% would be zero. Further, 95% of the time, approximately 75% of the installed capacity (at the aggregated level) remains unused.

These two observations suggest a cost function with zero cost for half of the aggregated capacity and a steep cost increase for the rest; these findings align with Ziras et al. (2020). This particular shape

[3] The cost for the first 25 A is 3000 €, with a charge of 230 € per additional Ampere (Radius Elnet, 2024).

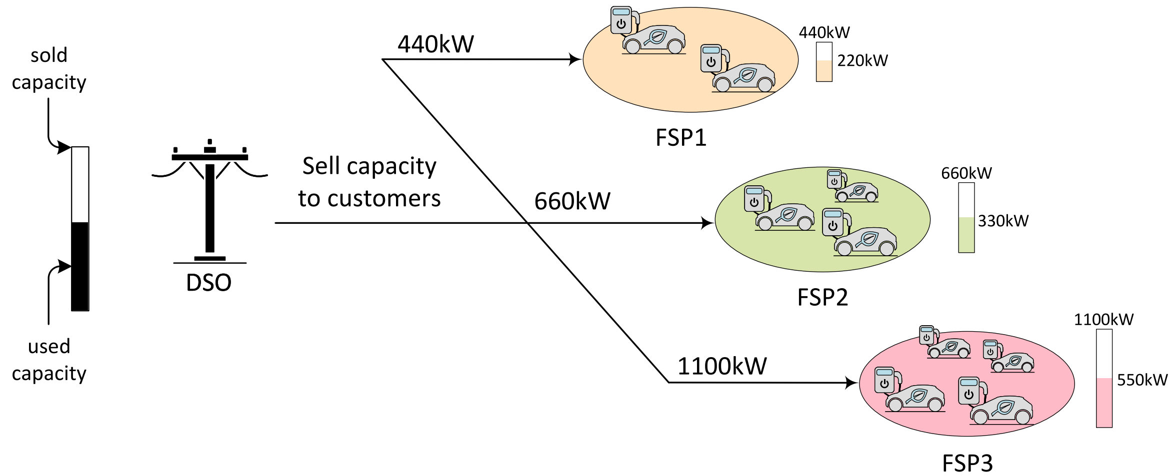

Fig. 1. Overview of sold network capacity and utilization for three different FSPs with 40, 60 and 100 11 kW EV chargers, respectively. Note that only the charger capacity (11 kW) is considered tradable and not the one of the household (17 kW) because FSPs are responsible only for the flexible EV demand.

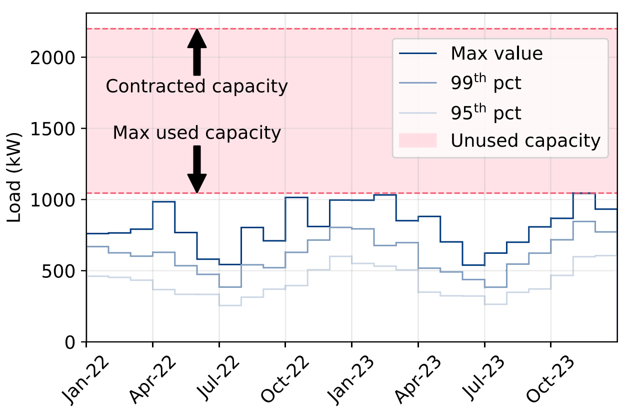

Fig. 2. Maximum, 99th and 95th percentiles of load for each month in 2022 and 2023 using 200 residential EV chargers optimizing against electricity prices.

of the commodity's (capacity's) valuation renders standard markets malfunctioning. Namely, a standard uniform-price auction for bought-back capacity would theoretically result in a clearing price of zero, if the returned capacity needed by the DSO was lower than 50% of the installed capacity; if the DSO needs to buy back a marginally higher amount of capacity, the price would take a sudden upward leap, leading to an odd situation where the vast majority of users would receive an unnecessarily high payment for selling back capacity that is far beyond what is used.

Another identified problem is DSO uncertainty regarding the amount of bought-back capacity needed, leading to a trade-off between efficiency (better achieved with service procurement closer to real-time) and security (better achieved with longer lead times), as pointed out in Hennig et al. (2024). This uncertainty creates the need for DSOs to buy back additional capacity in the same network area with different lead times depending on their forecast outcomes. In some cases, the purchase of part of the bought-back capacity could be rendered useless (e.g., lower than expected load growth), and the DSO could prefer to release and sell back part of the purchased capacity. The currently proposed nature of CLSs has the weakness that services cannot be easily stacked, adjusted and partially traded, as services come with specific strict requirements (e.g., accuracy and verification requirements or association with a specific FSP). This policy makes trading over multiple periods complicated or even impossible, leading to efficiency loss or overly complicated setups.

Recognizing the need for a market setup that effectively accommodates the particular cost structure of selling-back network capacity and the uncertainty in buying-back capacity from the DSO side, as well as the need for transparency and simplicity (Chondrogiannis et al., 2022; Hennig et al., 2022; Ziras et al., 2021), in the following subsection we address the above-mentioned issues with a proposed solution.

3.2. Proposed approach

We consider capacity reduction as a buy-back possibility for DSOs, where initially unrestricted network access of customers up to the contracted capacity is limited in return for a financial benefit (Hennig et al., 2023). This exchange takes place in a competitive environment via auctions in an LFM, and the procured services limit the allowed aggregated power of each FSP for specified periods in defined network areas and by the contracted amount. The distribution of profits to each FSP's customers is beyond the scope of this work.

Capacity blocks as a homogeneous product:. To address trading problems of multiple overlaying services and maintain a simple setup, we first introduce the concept of homogeneous *capacity blocks*. From the FSP perspective, the sale of a block represents a reduction of usable capacity by a fixed amount of X kW over the contracted period, while buying a block represents an increase of usable capacity by X kW. For the DSO, buying a block leads to a reduction of usable network capacity. Selling a block back to an FSP has the opposite effect as it increases usable capacity. The use of capacity blocks presents several advantages over trading explicit services:

- It eases the continuous adjustment of usable capacity over multiple periods (yearly, monthly, weekly, daily) as an FSP's capacity is determined only by the held capacity blocks over a certain period, instead of a collection of different services.
- It eases and streamlines the verification of service delivery in the presence of multiple contracts, as an FSP is not obliged to satisfy the requirements of various overlapping services, but is only bound by the number of held capacity blocks.
- It decouples the reduction of network capacity usage from delivering a specific service from an FSP to the DSO. Using an explicit service commits the FSP to a specific contract, preventing them from adjusting the sold capacity, such as buying back capacity from another FSP, as this would violate service requirements. Further, selling back capacity to the DSO also leads to conflicting services. Using capacity blocks facilitates this process, as an FSP simply needs to operate under the held capacity remaining at its disposal.

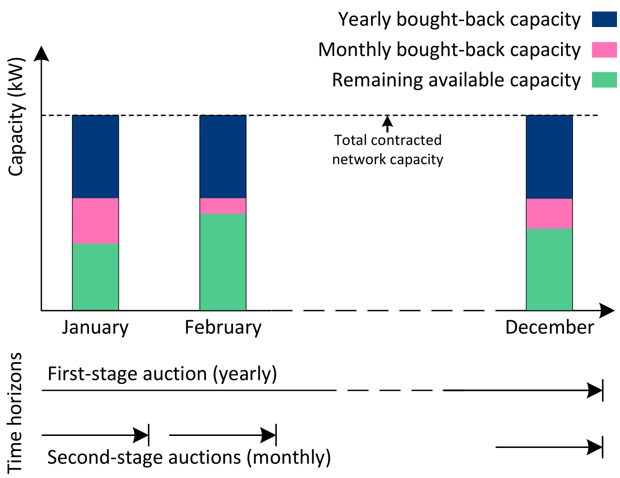

Fig. 3. Illustration of potential outcomes and the different time horizons of the proposed two-stage auction design.

Therefore, while the value of network capacity is by construct different per kW and viewing blocks as a homogeneous product is a matter of perspective and definition, the use of such blocks eases trading and allows the continuous adjustment of capacity in a harmonized manner. The introduced two-stage auction addresses this difference in the value per block.

Two-stage auction:. Facilitated by using a homogeneous product in the form of capacity blocks, a two-stage auction is proposed because it largely mitigates the adverse effects of excessive payments under uniform pricing. This mechanism is adopted to leverage the buyer benefits of *Two-Stage Procurement*: part of the quantity, that is safely known that will be needed and also falls within the low valuation band (because it is mainly unused), is procured in the first stage (e.g., yearly) at a low clearing price. An additional quantity is bought at a more frequent (e.g., monthly) second stage, at a higher cost and only when needed. In this scheme, the high cost of the marginal unit bought does not "poison" all of the units bought, but only the small quantity procured in the second stage. An illustration of the two stages of capacity limitation procurement is shown in Fig. 3.

4. Case study description

Residential EV charging data from the Danish e-mobility platform provider Spirii are used to model optimal charging and the provision of flexibility in an LFM. Plug-in/out times, charged energy and maximum power are available for each charging session. Two complete years (2022 and 2023) are used for the presented case studies; a detailed dataset description can be found in Ziras et al. (2024). The typical household network connection in Denmark is 25 A per phase (totaling 17 kW), limiting the possible charging power to 11 kW to allow the rest of the capacity to be used by the household. All-electric EVs currently represent approximately 90% of the total new registrations of EVs in Denmark (Statistics Denmark, 2024). For this reason, only vehicles with an on-board charging capacity of 11 kW are chosen from the dataset.

It is assumed that an FSP centrally controls EVs to minimize charging costs. Electricity prices are constructed based on the hourly spot prices of the bidding zone DK2 and the Danish DSO Radius' time-of-use tariffs. Radius operates the DN of Copenhagen and its surroundings. A flat tax and TSO fee per kWh are applied to residential customers, but these components do not affect optimal charging results. A penalty of 10 € per unserved kWh is imposed, and EV charging is optimized in a rolling-horizon fashion with a moving window of 15 minutes and an optimization horizon of 24 hours. This setup removes the unrealistic assumption of perfect EV data foresight. More details regarding the simulation and optimization framework are provided in the Appendix.

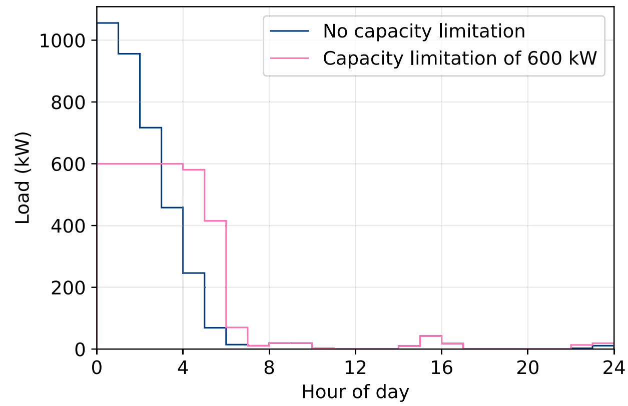

Fig. 4. Optimized consumption for an aggregation of 200 EV chargers on 23 Nov 2023 with and without a capacity limitation; hour is in local Danish time.

It should be noted that the *ex-post* costs incurred by reducing usable capacity over a period are calculated and used in the following case study. In other words, varying levels of capacity reduction are applied, and the corresponding FSP charging cost increase is calculated by comparing the constrained operation cost to the case without any power usage restrictions. The cost increase by the additional capacity limitation of a single block reflects the actual cost of selling this capacity. In practice, an FSP would need to forecast these costs over an upcoming period, similar to Ziras et al. (2020). However, the effect of forecasting uncertainty on cost estimations from the FSP's side and the impact on market clearing are beyond the scope of this work.

5. Results

5.1. Preliminary investigation

5.1.1. EV consumption analysis

The optimized consumption of 200 EV chargers is shown in Fig. 4, with and without a capacity limitation of 600 kW. In the unconstrained case, the load is concentrated in night hours (0–3 am) because of the typically lower spot prices and DSO tariffs between 0-6 am.[4] This result is the case for most weekdays because of the typical EV arrival (around 5 pm) and departure (around 7 am) times, while at weekends, the typically lower peak may appear during noon. A limitation in capacity shifts part of consumption to hours 3-6 am. To provide more insight into the aggregated EV consumption and some key metrics, we optimize the whole aggregation over 2022 and 2023.

The maximum, 99th and 95th percentiles of the aggregated EV loading are shown in Fig. 5 for each hour of the day. Despite the installed chargers' capacity of 2200 kW, the maximum load is approximately 1100 kW and occurs in night/early morning hours (which coincides with higher charger occupancy and lower electricity prices). Load does not exceed 740 kW during 95% of the time. These results imply a zero actual cost for a capacity reduction of 1100 kW (taking as reference the total installed capacity of 2200 kW). It is also expected that a limitation to 800 kW (i.e., a capacity reduction of 1400 kW) will incur a small cost to the providers because load rarely exceeds this threshold.

Fig. 6 shows the maximum and 95th percentile values for each month in 2022 and 2023 for the whole aggregation. Both metrics exhibit a seasonal variation, with lower values during the warmer months (May

[4] Radius and many other Danish DSOs apply a time-of-use volumetric tariff with high values between 5 and 9 pm and the lowest values between 0 and 6 am.

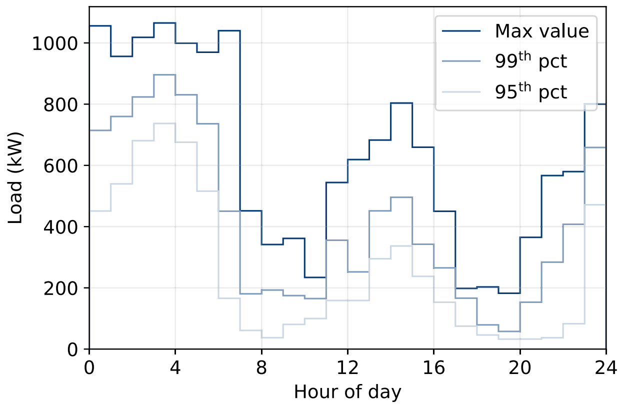

Fig. 5. Maximum, 99th and 95th percentiles of optimized consumption for an aggregation of 200 EV chargers for each hour of the day; no DSO service is applied, and the hour is in local Danish time.

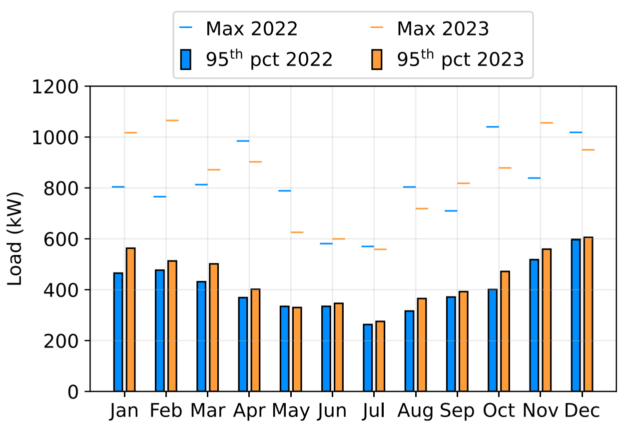

Fig. 6. Maximum and 95th percentile values for each month of years 2022 and 2023 for the whole aggregation of 200 EV chargers. No DSO service is applied.

to September), suggesting lower costs during those periods. While the maximum values vary between the two years, the 95th percentiles are more similar. These values provide a better indicator of the charging utilization than the maximum ones, which are highly dependent on outliers. This similarity suggests that electricity prices will be the main driving factor behind service cost differences between the two years, when considering the same EV portfolio.

5.1.2. *FSP costs under capacity reduction*

Fig. 7(a) shows the monthly cost curves of the FSP controlling 100 EVs based on the actual operating cost under reduced capacity from Jan 2022 until Dec 2023. Considerable cost variation across months is evident, along with a sharp increase in cost as the available capacity reduces. Subplot (b) shows the dependency on the average monthly electricity price. In general, higher spot prices lead to higher service costs, though monthly consumption also plays a significant role: in summer months, due to lower EV demand, costs are kept lower despite high electricity prices.

Fig. 8 shows the offering curve of the same FSP in 20 kW capacity blocks for November 2022. The FSP's installed capacity equals 1100 kW (100 EVs × 11 kW), corresponding to 55 blocks. The FSP withholds 100 kW of capacity (5 blocks), while the remaining 50 blocks are offered at varying prices. Only 14 out of 50 blocks incur a cost to the FSP during the month, which means that the aggregation does not consume more than 380 kW, and thus 36 blocks have zero cost.

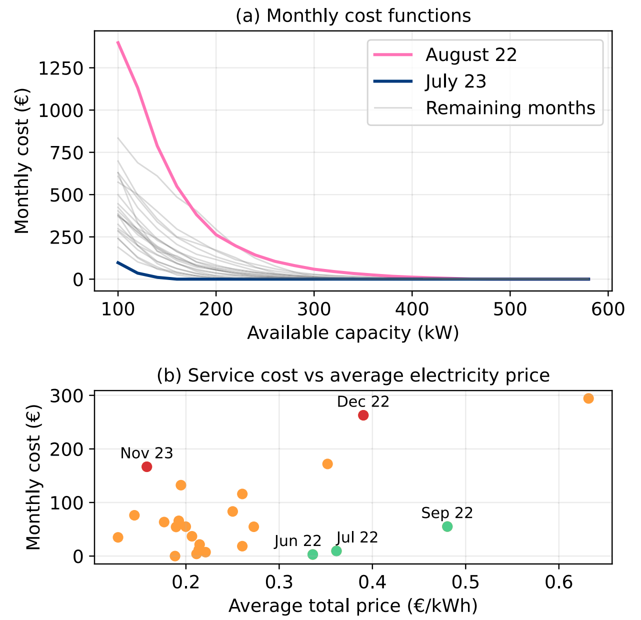

Fig. 7. Subplot (a): Cost curves of an FSP of 100 EVs each month between Jan 2022 and Dec 2023. Subplot (b): Monthly service cost against average monthly electricity price for an available capacity of 200 kW.

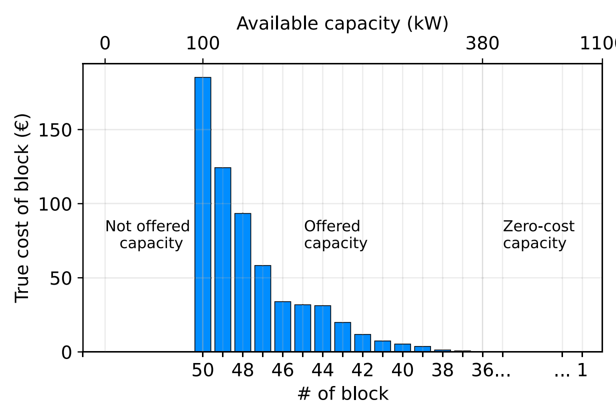

Fig. 8. Discretized offering blocks of an FSP of 100 EVs for November 2022.

5.1.3. *Remarks*

Analyzing the load profiles and actual service costs can give some important preliminary conclusions. First, load peaks occur in the night/early morning hours, and a capacity reduction flattens consumption within the typical EV plugged-in window, more evenly distributing consumption over the hours of low electricity prices. Consumption is thus flatter between 11 pm and 6 am; as a result, a service that covers this period or the whole day will lead to very similar load profiles and service costs in the case of residential chargers. Second, a large part, ranging from 50% to 75%, of an aggregation's capacity is never utilized. This unused capacity has important repercussions in market clearing, as shown next. Third, capacity utilization varies considerably throughout the year, and the variation in unused capacity also has implications for market clearing, depending on the timeframe that services are auctioned.

5.2. *Market clearing*

5.2.1. *Effect of excess capacity in market clearing*

To show the impact of non-utilized capacity in market clearing, we apply uniform pricing for each month of the two-year dataset and

Table 1
Summary of DSO payments, FSP profits and actual cost in € for two years of monthly capacity limitation auctions.

Remaining capacity	DSO payments	FSPs profit	FSPs actual cost
500 kW	21 879	20 430	1449
600 kW	8432	7917	515
700 kW	2505	2344	161

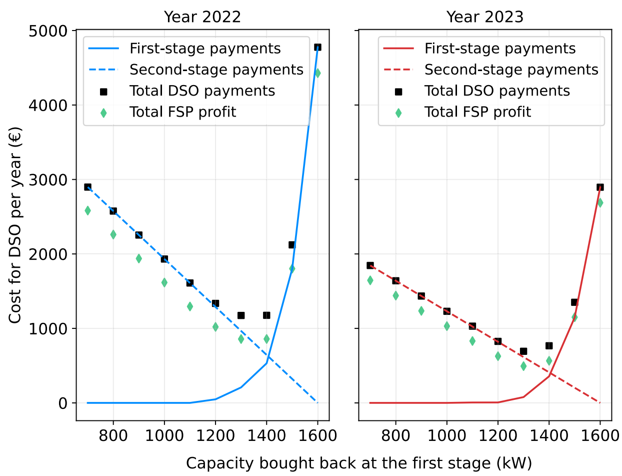

Fig. 9. Service costs and FSP revenue for two-stage auctioning for 2022 and 2023 - remaining capacity is always set to 600 kW.

present the aggregated result in Table 1. The DSO cost (total payments to the FSPs), the total revenue of all three FSPs, and their actual costs are shown. Three different amounts of capacity are bought back (1700 kW, 1600 kW and 1500 kW) so that the remaining capacity is 500 kW, 600 kW and 700 kW, respectively. In this and all subsequent results, we assume that the DSO decides to have the same remaining capacity every month. In future studies, where we consider the impact of the uncontrollable load, we will examine cases with varying amounts of monthly purchased capacity.

As shown in Fig. 2, the unrestricted aggregated EV loading is limited to approximately 1000 kW for an aggregation of 200 chargers. Restricting EV loading to even 700 kW leads to a considerable payment of 2500 € over two years. Payments increase dramatically as the service is more restrictive, and in our case eight-fold for an additional reduction of 200 kW. Notably, actual FSP cost is only 7% of the total payments, so the reason for the very high payments is the profit margin due to the market clearing, rather than the actual cost incurred by offering the service.

5.2.2. Two-stage auction

One way to decrease DSO payments and bring them closer to FSP actual costs is by employing a two-stage auction. In the first stage, capacity is auctioned for a whole year, while the remaining capacity is purchased monthly. In both auctions, uniform pricing is applied. In the following, only a DSO remaining capacity of 600 kW will be considered to ease the presentation of the results; in other words, the DSO needs to remove 1600 kW of capacity. Results are presented in Fig. 9 and Table 2.

As shown in Fig. 9, first-stage DSO payments are zero until the value of non-utilized capacity of approximately 1100 kW, but rise sharply to 4776 € in 2022 and 2896 € in 2023 when all needs are covered at the first stage. Second-stage payments decrease linearly as more capacity is bought at the first stage. They start at 5152 € in 2022 and 3280 € in 2023 (as in the previous case of exclusively monthly auctions) and fall to zero when all 1600 kW are bought in the first stage.

A more reasonable strategy is to purchase a moderate amount of capacity at the first stage (1300-1400 kW or 65-70 blocks) and resort to

Table 2
Summary of DSO payments, FSP profits and actual cost in € in the two-stage market clearing.

Amount bought in first stage	Year	DSO payments	FSPs profit	FSPs actual cost
Zero	2022	5152	4837	315
	2023	3280	3080	200
1300 kW	2022	1174	857	317
	2023	693	493	200
1600 kW	2022	4776	4428	348
	2023	2896	2688	208

Table 3
Summary of DSO payments, FSP profits and actual cost in € for two years under different auctions. A total capacity of 600 kW is left under all cases.

Type	DSO cost	FSPs profit	FSPs actual cost
Monthly auctions	8432	7917	515
Two-stage auction	1867	1351	516
Capacity removal	3162	2647	515

monthly auctions for the remaining needs; buying too little capacity leads to higher total payments because substantial excess capacity remains during the monthly auctions. The optimal two-stage capacity purchase leads to total payments of 1867 € for both years combined, a significant reduction of more than 70% compared to the single-stage, monthly or yearly auctions. While still the largest part of DSO payments is profit for the FSPs, actual costs now represent around 30% of DSO payments, a marked increase from only 7% in the single-stage monthly auctions.

5.2.3. Removal of excess capacity as a participation requirement

Given the large share of non-utilized capacity, we consider a case where the DSO requires FSPs to relinquish 45% of their capacity if they wish to participate in the market. In this case study, 50 blocks (equivalent to 1000 kW) were removed, and uniform pricing was applied each month (single-stage auction). This design option is based on the fact that actual FSP costs for selling back the first half of their capacity is practically zero because it is never utilized. As a result, temporarily selling back this part of their capacity constitutes no *useful* service from FSPs. This share of 45% may be periodically updated based on analyses with actual EV charging data on a national level.

Table 3 presents the total DSO payments, FSP profits, and FSP actual costs over the two years under different auctions. Interestingly, mandatory capacity removal leads to higher total payments than the two-stage auction, where the DSO pays FSPs for the first-stage capacity purchase. A more careful inspection of Fig. 9 points in that direction. The removal of 1000 kW is equivalent to buying back the same amount in the first-stage auction. However, the buy-back of such a small amount in the first stage is not optimal, as a large part of excess capacity (zero-cost blocks) remains in the monthly auctions, increasing payments under uniform pricing. It is beneficial for the DSO to remove more capacity in the first stage. While this can be done readily by auction, forcibly removing larger portions of the total capacity cannot be easily justified, as this would mean removing utilized capacity with zero remuneration.

6. Discussion and future considerations

In this work, we proposed a straightforward product, namely equally-sized capacity blocks, capable of addressing congestion problems in DNs. FSPs can value the product without the uncertainties baselines or service activations introduce. Here, we discuss important aspects of implementing an LFM based on trading capacity blocks.

Our proposed setup considers a market clearing with a two-stage auction on a yearly and monthly basis, and primarily addresses structural congestion (Council of European Energy Regulators (CEER), 2020). The purpose of the first stage is to remove excess capacity of no or very little value and avoid excessive payments under uniform pricing in subsequent auctions. Depending on its operational strategy, a DSO might buy back capacity weekly or daily either as a second or third-stage auction. The exact timeframes can be adjusted depending on the nature of congestion, i.e., structural or sporadic, and if there are few days with limited hosting capacity (for example, due to frigid weather or network maintenance).

Uncertainty in the operation of the DN should be further investigated by incorporating real DN models and consumption components (such as households, commercial loads, heat pumps etc.), and studying how buying back capacity would perform as a solution. In that case, considering an inelastic DSO demand curve, which was used in this case study, should be revisited. The DSO could express its willingness to buy back capacity through an elastic cost curve, which three factors drive:

- Quantifying the cost of congestion in terms of overloading of components (loss of life) or blackouts.
- Expressing the uncertainty of demand that is not participating in the LFM.
- Probabilistically assessing the impact on DN loading of buying back different capacities from FSPs. For example, buying back 1000 kW of capacity will affect network loading differently, depending on how much capacity each FSP sells.

The DSO could protect the network against unforeseen and rare events, such as faults caused by equipment failure, by buying back larger amounts of capacity. However, this may not be optimal, and a probabilistic assessment would be necessary to quantify the risk of congestion against the amount (and cost) of bought-back capacity. The product design of tradable capacity blocks gives the DSO the option to purchase further capacity in anticipation of high operational risks, for example, day-ahead, as an extension to the main yearly-monthly stages shown in this work. This feature is another motivation behind trading capacity as blocks because it allows for a simple re-adjustment of usable capacity depending on each participant's needs and expectations. Further, trading capacity under the proposed scheme has little effect on imbalances caused by FSP actions on balance responsible party positions, as capacity is primarily to be sold to DSOs before day-ahead commitments.

As shown from the case study, the importance of removing non-utilized capacity in the first stage is high. FSPs may choose to abstain from the first-stage auction to push the cleared prices and payments up in the second stage; of course, this will have a similar effect to the first-stage outcome. However, this means they will lose their respective profits, in anticipation of more profits in the second-stage auction. Further, the capacity bought by the DSO may differ per month in practical applications, and the second-stage price may be subject to high volatility. Therefore, it can be expected that risk-aware FSPs would participate truthfully in both stages and try to secure profits in the first stage.

Another possibility of gaming arises in the case of enabling peer-to-peer trading of capacity among FSPs, which can increase efficiency and lead to potential gaming behavior. An FSP might withhold all its capacity in the first-stage auction, resulting in the rest of the FSPs selling more capacity and receiving high payments, especially if the non-participating FSP has a substantial portfolio. Then, this FSP may sell half of its capacity (which has zero opportunity cost) to the other FSPs at relatively low prices or participate in the second-stage auctions and inflate its profits. In principle, this behavior should be discouraged as it attempts to manipulate the market outcomes. One possible solution would be to remove the non-utilized capacity of FSPs that exhibit this behavior or strategically abstain from the first-stage auction. The amount of non-utilized capacity to be removed should be justified by up-to-date nationwide statistical analyses of relevant data.

In all cases, it is desirable to withdraw non-utilized capacity in the first-stage auction to avoid market distortions. This objective can be achieved by incentivizing FSPs to participate in the first stage, e.g., by introducing price floors in the cleared price to secure profits or limiting the amount of capacity FSPs can trade at subsequent stages depending on certain conditions. The removal of the non-utilized capacity of non-participating FSPs should ideally be avoided.

Another important aspect not addressed in this work is the consideration of ex-post FSP cost calculations. FSPs should forecast the expected cost of selling back capacity to the DSO, which involves using forecasts for EV consumption data (though there seems to be little difference on a year-to-year basis (Ziras et al., 2024)) and electricity prices. The offering strategies of FSPs under uncertainty and the impact on market clearing outcomes should be further investigated. Finally, there is an apparent trade-off in choosing the size of capacity blocks: a larger size creates market inefficiencies and discourages the participation of smaller FSPs, but a smaller size leads to excessive amounts of blocks and a more complicated market operation. The impact of capacity block size on the market clearing should be further investigated.

7. Conclusion

The significant increase in the deployment of DERs and their use in the wholesale and ancillary service markets challenge the reliable operation of DNs and necessitate congestion management measures. One solution to support DSOs in mitigating network congestion is LFMs. While some form of temporarily limiting DER usable capacity is seen as a promising solution, a standardized framework that does not suffer from uncertainty propagation, service-trading problems, and overly tailored decision-making DSO needs does not exist. We address these issues and propose auctioning and trading aggregated network capacity in equally sized capacity blocks.

Based on two years of EV charging data from Danish residential customers, we find that the actual aggregated utilization is below 50% of contracted capacity. This situation leads to excessive DSO payments and FSP profit margins under a uniform pricing scheme, due to large amounts of free (unused) capacity. To this end, we propose and empirically demonstrate the efficacy of a two-stage auction, which leads to reduced payments and more reasonable profit margins. We further show how such an auction leads to lower payments than forcibly removing excess capacity from FSPs without compensation. These results suggest that using a two-stage (or multi-stage) auction of capacity limitation through small-sized blocks can be a simple, competitive, and efficient way to handle congestion in an LFM environment.

Our future work will study the effect of load uncertainty (from load not participating in the LFM) in the decision-making process of the DSO and the effect of FSP opportunity cost forecasts (instead of using ex-post calculations) on the operation of the proposed market. We will further investigate gaming opportunities under the proposed scheme and potential countermeasures that will incentivize FSPs to participate in the first-stage auction and not strategically withhold large amounts of capacity.

CRediT authorship contribution statement

Charalampos Ziras: Writing – original draft, Visualization, Validation, Methodology, Investigation, Funding acquisition, Formal analysis, Conceptualization. **Jan Martin Zepter:** Writing – original draft, Visualization, Validation, Methodology, Investigation, Formal analysis. **Shahatphong Pechrak:** Methodology, Investigation, Formal analysis, Conceptualization. **Georgios Tsaousoglou:** Writing – original draft, Methodology, Investigation, Funding acquisition, Formal analysis.

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.

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Appendix. Mathematical optimization model for EV charging

Below we present the mathematical model used to optimize the EV charging of an FSP. The goal of the model is to minimize total charging costs while respecting the physical limits of the chargers and any capacity limitations. Let $\mathcal{N}$ denote the set of EVs connected at chargers at the current time step, and $\mathcal{T}$ represent the number of time steps within a 24-hour rolling horizon, with each step t corresponding to a 15-minute interval. Upon arrival, the energy demand and departure time of the EV become known. Then, the objective function is formulated as follows:

$$\min \sum_{t\in\mathcal{T}}\sum_{j\in\mathcal{N}} P^{\mathrm{EV}}_{(t,j)} \cdot \pi_{(t)} \cdot \Delta T + \sum_{j\in\mathcal{N}} s\_e_{(j)} \cdot c^{\mathrm{pen}}, \tag{1}$$

where $P^{\mathrm{EV}}_{(t,j)}$ refers to the power consumption of each EV $j \in \mathcal{N}$, and $\pi_{(t)}$ denotes the electricity buying price, including spot prices as well as variable grid tariffs and other duties in each step $t \in \mathcal{T}$. Unserved energy per EV, $s\_e_{(j)}$, is added to the total costs with a penalization factor c^{pen}. ΔT is a time-normalization constant equal to 0.25 for a 15-minute interval.

The objective function is subject to a set of constraints. Eq. (2) requires the sum of power consumption from the EVs to remain below the maximum allowable capacity limit $cap_{(t)}$. Eq. (3) limits the individual power drawn by each EV to the respective charger limit $P^{\max}_{(j)}$ for all time steps where EV j is plugged in ($t \in \mathcal{T}^{j}$). For the time steps after the departure of EV j ($t \in \mathcal{T}^{*,j}$), its power consumption is zero, as expressed by Eq. (4).

Eq. (5) ensures that EV demand is either satisfied or counted as unserved demand, which is penalized accordingly in the objective function. $E_{(j)}$ is the remaining energy demand, i.e., the corresponding energy need of the charging session minus any energy already provided during the charging process. Eqs. (6) and (7) ensure the non-negativity of the model's decision variables.

$$0 \le \sum_{j\in\mathcal{N}} P^{\mathrm{EV}}_{(t,j)} \le cap_{(t)} \quad \forall t \in \mathcal{T} \tag{2}$$

$$P^{\mathrm{EV}}_{(t,j)} \le P^{\max}_{(j)} \quad \forall t \in \mathcal{T}^{j},\ \forall j \in \mathcal{N} \tag{3}$$

$$P^{\mathrm{EV}}_{(t,j)} = 0 \quad \forall t \in \mathcal{T}^{*,j},\ \forall j \in \mathcal{N} \tag{4}$$

$$\sum_{t\in\mathcal{T}^{j}} P^{\mathrm{EV}}_{(t,j)} \Delta T + s\_e_{(j)} = E_{(j)} \quad \forall j \in \mathcal{N} \tag{5}$$

$$P^{\mathrm{EV}}_{(t,j)} \ge 0 \quad \forall t \in \mathcal{T}^{j},\ \forall j \in \mathcal{N} \tag{6}$$

$$s\_e_{(j)} \ge 0 \quad \forall j \in \mathcal{N} \tag{7}$$

Data availability

The authors do not have permission to share data.

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