A Decentralised Privacy-Preserving Solution for Home Battery Concurrent Charging Mitigation

Nam Trong Dinh
Principal Data Scientist
OptiGrid Pty Ltd
Adelaide, Australia
trongnam.dinh@adelaide.edu.au

S. Ali Pourmousavi
School of EME
The University of Adelaide
Adelaide, Australia
a.pourm@adelaide.edu.au

Jon A. R. Liisberg
Data Science Department
Watts A/S
Køge, Denmark
jon.liisberg@watts.dk

Julián Lemos-Vinasco
Data Science Department
Watts A/S
Køge, Denmark
julian.lemos@watts.dk

***Abstract*—Price-responsive home energy management systems (HEMS) optimise battery charging based on electricity prices, leading to concurrent charging during low-price periods and creating new peak demand challenges for distribution networks. This paper presents a decentralised, hence scalable, dynamic import limit strategy that constrains battery charging power based on price volatility and a daily budget. The proposed method distributes charging activity across wider time intervals whilst maintaining cost efficiency for residential users. Simulation results using real data from 24 residential customers in Denmark's two pricing zones demonstrate significant peak reduction, with aggregated charging power reduced by more than 50% at times under a daily budget constraint of only 4.0 DKK. The framework adapts flexibly to price fluctuations whilst ensuring daily budgets are never exceeded and only rarely approach the limit, providing network operators with predictable grid management tools without compromising customer autonomy or privacy.**

***Index Terms*—Home energy management, battery storage, peak demand, distributed energy resources**

I. INTRODUCTION

The proliferation of residential battery energy storage systems coupled with price-responsive home energy management systems (HEMS) presents both opportunities and challenges for electricity distribution networks. An HEMS is a physical device installed in customers' homes to optimise the operation of home batteries and rooftop PV systems directly at the inverter level by minimising the electricity cost using forecasts of solar PV generation, household electricity consumption, and hourly electricity prices. As such, batteries are typically charged during the day when solar energy is abundant or electricity prices are low. If sufficient solar energy is available, HEMS prioritises charging the battery directly from solar generation. However, in scenarios where solar energy is not available, such as during the autumn and winter months or for homes without a rooftop solar system, HEMS often resorts to charging batteries from the grid. Even when solar energy is abundant but electricity prices are highly negative, HEMS can choose to curtail solar energy and charge the battery from the grid to maximise revenue.

Although HEMS offer significant benefits for individual households through electricity cost optimisation, their homogeneous response to identical price signals creates substantial grid management challenges. When multiple HEMS devices operate using similar algorithms and respond to the same price incentives, home batteries tend to charge concurrently during low-price periods, resulting in sharp increases in local grid demand that can exceed traditional peak demand periods. Alternatively, during high-price periods, many home batteries discharge to feed into the grid when participating in a virtual power plant (VPP) scheme or buy electricity at wholesale market prices, causing massive reverse power flow and voltage rise problems.

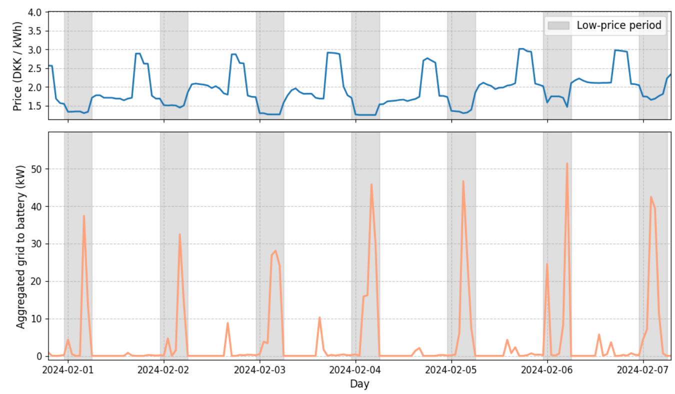

Fig. 1. Aggregated battery charging peaks driven by uniform incentives and HEMS algorithms. Upper Panel: electricity price profile, Lower Panel: Actual data from Watts A/S HEMS on aggregated grid-to-battery charging power, Shaded Areas: low-price periods

This behaviour is illustrated in Fig. 1, where the batteries charge mainly when prices are low, typically after midnight. Charging activity also occurred during the lowest price points within these periods. This results in the formation of a new peak demand, which can potentially be even higher than the typical peak demand observed during the early evening due to the high power of the batteries. A similar issue can arise during the day, typically in summer, when electricity prices are negative, so batteries may charge concurrently from the grid even when solar energy is available. This issue could worsen as more devices, such as electric vehicles (EVs), are autonomously operated by the HEMS and/or actively participate in the wholesale market through aggregators and VPP operators, putting more strain on local networks and requiring expensive network upgrades.

A. Literature Review

One of the most commonly adopted approaches to reduce residential peak demand is the implementation of peak demand

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charges [1], [2]. These charges encourage consumers to even out their electricity use by assessing costs based on their peak power usage in a single interval during the billing cycle. This peak measurement determines the daily surcharge for the entire period, even if the household uses less power at other times, to encourage sustained reduction in peak demand. As a result, many distribution network service providers (DNSPs) in Australia, such as Ausgrid in New South Wales, have incorporated peak demand charges into their default network rates for newly connected households [3]. Ausgrid's demand charge is applied only during a six-hour window from 3 PM to 9 PM in the summer and winter months. For traditional households, this period effectively captures the peak demand at night and any potential load shifting to nearby intervals. However, for modern households equipped with HEMS, home batteries, and EVs, load rebound can occur at any time of the day. This rebound is likely to coincide with other households in the neighbourhood due to identical responses to uniform price signals, as discussed earlier.

A relatively simple solution to this issue is to extend the demand charge to cover all hours of the day. However, this does not align with the purpose of cost-reflective tariffs [4]. Cost-reflective tariffs are designed to signal the actual costs of providing network services, with peak demand being the primary driver of network investment. Because peak demand occurs only during a few intervals each day, applying demand charges uniformly throughout the day would undermine this principle, imposing unnecessary costs on consumers during periods when the network is not under significant strain. Moreover, demand tariffs remain challenging for many consumers to understand, who often face public backlash [5], [6]. This complexity is exacerbated by the fact that the charges are based on past peak demand events that customers can no longer influence and are typically only revealed at the end of the billing period, leaving consumers unable to adjust their behaviour proactively. For this reason, South Australia's DNSP has eliminated demand charges for residential customers starting in 2024 [7]. This change aims to simplify the network tariffs by considering a structure that includes only fixed charges and ToU volumetric components. Similarly, the major distribution service operators in Denmark have adopted a tariff structure that relies solely on fixed charges and ToU volumetric components, emphasising simplicity and transparency in network pricing [8], [9].

As simultaneous peak demand arises when all HEMS react uniformly to identical price signals, the authors in [10] suggested dividing customers into distinct groups, each group presented with different ToU tariff. However, this raises challenges in establishing a fair pricing system, especially when customers may have varying routines and energy use patterns throughout the day, making it difficult to ensure fair treatment between different pricing groups. Alternatively, in [11], [12], the authors proposed a different approach by introducing dynamic operating envelopes. These envelopes set flexible bounds on how much power each household can import or export at any given time, which is an improvement over the fixed import and export limits traditionally imposed by DNSPs [13]. Although this method effectively controls peak demand within a local neighbourhood, it is based on a centralised approach. The operator must forecast the net demand of each household and aggregate these forecasts to calculate the bounds for each customer or group. Furthermore, there is no explicit mapping between the imposed bounds and the financial impact on customers, leaving the associated costs unquantifiable and potentially undermining transparency and fairness. Therefore, using dynamic bounds that account for financial impact on customers appears to be more effective.

B. Contributions and Paper Organisation

To address these challenges, the solution proposed in this paper aims to avoid the high peak demand caused by concurrent battery charging. A key requirement is to leverage the existing software infrastructure and communication channels of HEMS, ensuring efficient and cost-effective deployment without the need for significant additional resources or modifications. Furthermore, HEMS installed at the home of each customer must be able to reduce peak demand within the local grid independently, rather than relying on a central mechanism, to preserve customer privacy and solution scalability. This is achieved through a decentralised control strategy for home batteries. However, shifting battery operations away from their optimal actions can lead to reduced revenue or higher costs for consumers. These costs can potentially be recouped through compensation from network operators by providing specific grid services. As such, the method proposed in this paper balances improving grid performance metrics and maintaining cost efficiency for users. Note that the scope of this paper is limited to dynamic import bounds specifically for home batteries. The key contributions include:

1) A fully local solution operating on individual HEMS devices without requiring centralised coordination, preserving customer privacy.
2) Explicit mapping between operational constraints and customer costs through daily budgets.
3) Dynamic adjustment of import limits based on real-time price volatility whilst maintaining customer cost preferences.
4) Integration with existing HEMS infrastructure without requiring significant modifications or additional resources.

The paper is organised as follows: Section II details the proposed methodology including dynamic import limit calculation and integration processes. Section III presents simulation studies using Danish residential data, accompanied by discussions on outcomes and implications for grid management. Section IV concludes with future research directions.

II. Methodology

The goal is to create a methodology that fulfils two key criteria: 1) it must operate without any hardware changes and 2) it should work on the consumer's HEMS with minimal interaction with the aggregator to protect consumer privacy and ensure scalability. Figure 2 illustrates a high-level flow-chart depicting existing and new HEMS components, including the input parameters introduced for the newly proposed method. Our industry partner (Watts A/S) can efficiently implement this solution as a software update for the HEMS. In the subsequent sections, we discuss modifications to the optimisation engine, the dynamic import limit calculator, and the daily budget.

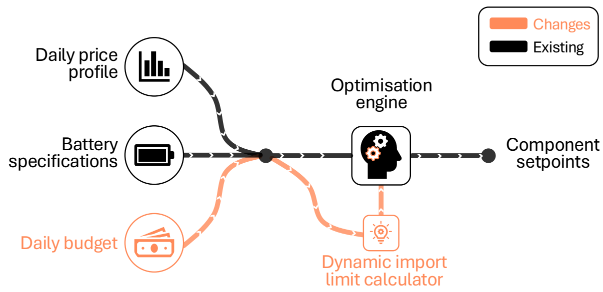

Fig. 2. Overview of the HEMS and the changes made to implement dynamic import limits on battery charging power.

A. HEMS Modification

Given that new peak occurrences are typically observed after midnight or around noon during periods of negative pricing (see Fig. 1), times when household activity is low and demand remains fairly stable, these peaks are likely tied to battery operations. Consequently, demand is less affected by real-time variables such as price changes, making them less critical for the immediate goal of peak reduction. Therefore, dynamic import limitations could be applied exclusively to the charging of home batteries from the grid to avoid simultaneous battery charging on the local grid. This approach is feasible since the original HEMS optimisation algorithm developed by Watts A/S includes a distinct decision variable for grid-based battery charging [14], similar to (1):

$$\min_{g_t^b} \sum_{t \in T} \frac{\lambda_t^+ \cdot g_t^b}{\eta^+} \cdot \Delta t \tag{1}$$

where g_t^b represents the battery charging power from the grid at interval t, η^+ is the charging efficiency, and Δt is the duration of the time interval. We then incorporate the constraint (2) into the existing optimisation framework in [14].

$$g_t^{\mathrm{b}} \leq \overline{G}^{\mathrm{b}} \quad \forall t \in \mathcal{T}, \tag{2}$$

where $\overline{G}^{\mathrm{b}}$ is the dynamic import limit, which is discussed in the next section.

B. Dynamic Import Limit Calculator

The dynamic import limit calculation relies on three primary inputs illustrated in Fig. 2:

1) **Daily Price Volatility**: Reflects fluctuations in electricity prices that impact both the costs of arbitrage and the magnitude of charge. Watts A/S customers are exposed to day-ahead wholesale prices from Nord Pool, which are determined 12-36 hours ahead. This pricing information is transmitted to HEMS via Watts A/S in the existing system.
2) **Battery Specifications**: The energy capacity and charging power limits that determine the financial impact of dynamic constraints. This data is already accessible to HEMS.
3) **Daily Budget**: This is a new input in the proposed solution, as shown in Fig. 2, which represents the maximum cost a customer incurs daily to spread the battery charging.

The optimal charging power limit determination involves establishing a cost baseline for unconstrained battery charging, representing the cost of charging from minimum to maximum state of charge at maximum power during lowest-price intervals.

$$\mathrm{C}_{\mathrm{uc}} = \sum_{t \in T_{\mathrm{low}}(T_{\mathrm{full}})} \frac{\lambda_t^+ \cdot g_t^b}{\eta^+} \cdot \Delta t \tag{3}$$

where T_{full} represents the battery duration in hours and $T_{\mathrm{low}}(T_{\mathrm{full}})$ denotes the T_{full} intervals with the lowest electricity prices. For different constrained power limits, the cost calculation becomes:

$$\mathrm{C}_{\mathrm{con}} = \sum_{t \in T_{\mathrm{low}}(T_{\mathrm{limit}})} \frac{\lambda_t^+ \cdot \overline{G}^b}{\eta^+} \cdot \Delta t \tag{4}$$

where $\overline{G}^b = S_{\mathrm{max}}/T_{\mathrm{limit}}$, with S_{max} representing battery capacity and T_{limit} the charging duration under the power limit. The optimal dynamic import limit can then be determined by solving the following optimisation problem:

$$\min_{T_{\mathrm{limit}}} \quad \overline{G}^b \tag{5a}$$
$$\text{s.t.} \quad \mathrm{C}_{\mathrm{con}} - \mathrm{C}_{\mathrm{uc}} \leq \text{Daily Budget}, \tag{5b}$$
$$\overline{G}^b = \frac{S_{\mathrm{max}}}{T_{\mathrm{limit}}}, \tag{5c}$$
$$T_{\mathrm{limit}} \geq T_{\mathrm{full}}, \tag{5d}$$
$$T_{\mathrm{limit}} \in \mathbb{Z}^+ \tag{5e}$$

To account for realistic battery operations involving multiple daily charging cycles, the import limit calculation is divided into two periods: post-midnight to early morning and afternoon hours. The daily budget is then distributed across these periods, with heavier weighting toward the post-midnight period, where charging predominantly occurs due to lower electricity prices. As a result, two $\overline{G}^b$ will be determined each day. This modification ensures an accurate representation of battery operations in real operation and maximises strategy effectiveness.

C. Daily Budget

As evidenced later in the simulation results, the effect of the amount of the daily budget on the performance of the proposed method is minimal. However, it is appropriate to consider the origins of this daily budget in the proposed solution. There are several methods to establish the daily budget. One straightforward approach is to have customers indicate their preferences via the Watts A/S app, allowing them to adjust as desired over time. Given the relatively low expected daily budget needed (not more than one unit of the peak electricity price) for the proposed solution to be effective, this could indeed be an option that customers weigh for the betterment of their community and the future smart grid. In this case, customers may incur a slightly higher energy cost than they would under an unconstrained optimisation, though in practice this cost tends to be well below the budgeted value. Their contribution helps reduce local demand peaks and enhances distribution network efficiency, which may facilitate increased adoption of batteries and price-sensitive devices over time, ultimately lowering electricity costs for end users. Alternatively, the aggregator could monetise these services (e.g., by providing them to DNSPs to avoid expensive network upgrades) and remunerate customers for their participation. In this scenario, the aggregator would set the daily budget value and bear the cost, which could then be recovered through network service agreements. The simulation results in the next section illustrate the influence of the daily budget on the efficacy of the proposed solution.

III. Case Study and Results

A. Simulation Setup

The proposed methodology was evaluated using data from 24 residential customers evenly distributed in Denmark's two electricity pricing regions, namely DK1 (West Denmark) and DK2 (East Denmark). The simulation period spanned 105 days from 17 December 2023 to 30 March 2024, covering late winter to early spring conditions. Battery systems varied in capacity and power ratings, with some customers having battery systems with a power limit of 10 kW or more.

To evaluate the effectiveness and realistic cost estimations of the proposed dynamic import limits compared to the existing HEMS solution, the model is tested using the receding horizon optimisation (RHO). In this setup, forecasts of household electricity consumption and rooftop solar PV generation, together with day-ahead electricity prices, are used as input to the optimisation model for each interval. This approach aligns with how Watts A/S' HEMS operates in practice, continuously updating its decisions based on forecast updates. However, storing and maintaining rolling forecast data for residential customers presents challenges, including storage limitations and privacy concerns. Therefore, actual rolling data were not available from HEMS. To address these issues, customer behaviour models described in [15] and [16] are used to generate synthetic rolling forecasts for household demand.

B. Weekly Operation Analysis

Figure 3 demonstrates the operation of dynamic import limits during the first week of February 2024, comparing the actual aggregated charging peaks with the results of the proposed model under a budget of 4.0 DKK in DK2. The results confirm that the aggregated peak charging power remains strictly below the dynamic limit throughout the week, providing a reliable peak management tool.

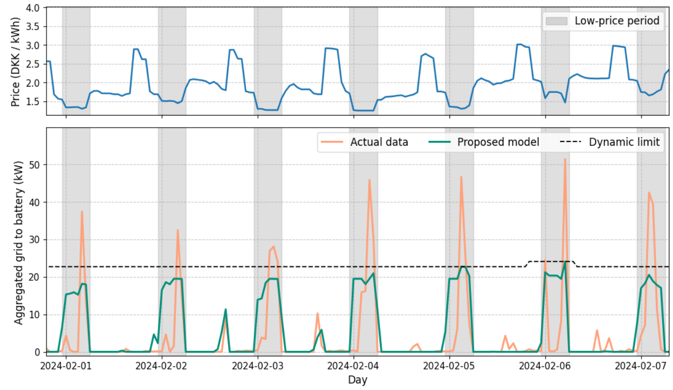

Fig. 3. Aggregated battery charging peaks comparison: baseline condition versus the proposed model with 4.0 DKK daily budget in DK2.

The dynamic import limit adapts to price volatility, with higher limits during increased price volatility periods (e.g., 6 February 2024), whilst ensuring daily budget constraints are respected. This flexibility aligns with customer willingness to pay whilst contributing to better grid management.

C. Impact of Dynamic Import Limits

Table I summarises the average reduction in peak demand achieved in different daily budget scenarios. The implementation of dynamic import limits demonstrates a significant reduction in peak charging power across both pricing zones.

TABLE I
The Average Peak Charging Power Reduction Results

Daily Budget (DKK)	DK1 Peak Reduction	DK2 Peak Reduction	Average Reduction
2.0	47.3%	45.8%	46.6%
4.0	52.1%	53.7%	52.9%

Figure 4 shows the hourly peak and mean of the aggregated battery charging power in the 2.0 DKK and 4.0 DKK daily budgets compared to the baseline condition for both pricing regions for 105 days of simulation. Both scenarios demonstrate substantial improvement over baseline conditions, with charging activity distributed more evenly throughout the early morning period (12-5 AM) than concentrated within 1-2 hours at maximum power.

D. Customer Cost Impact Analysis

Figure 5 presents the distribution of the daily cost increases for customers under dynamic import limits in 105 days of simulation. The analysis reveals that actual costs consistently remain below respective daily budgets and represent less than 1% of customers' daily electricity costs throughout the simulation period.

This occurs because daily budgets are not always fully used. On days with minimal home consumption or relatively flat electricity prices during charging periods, customers incur little to no additional costs. This is because the battery does not require charging from the grid for later home use. This ensures customers maintain energy use flexibility whilst contributing to grid stability without financial drawbacks.

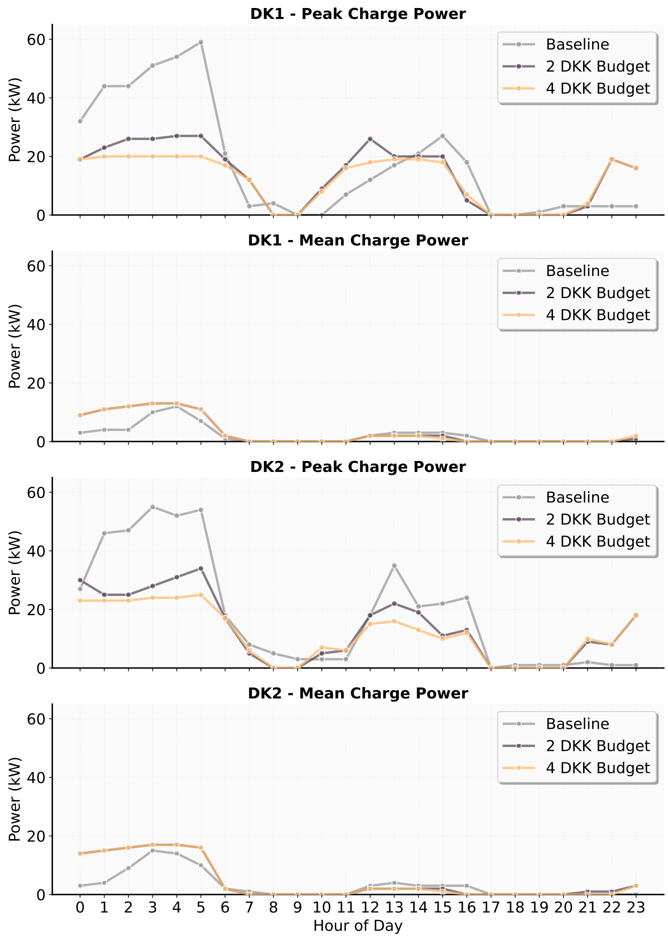

Fig. 4. Hourly maximum and mean of aggregated battery charge power for the proposed solution compared to the baseline condition.

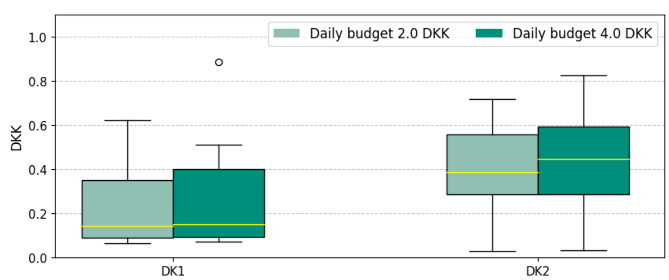

Fig. 5. Distribution of customers' daily cost increases for DK1 and DK2 under dynamic import limits.

IV. Conclusion and Future Work

This paper presents a novel decentralised approach to mitigate the peak demand for price-sensitive home battery systems through dynamic import limits. The proposed methodology successfully addresses the challenge of concurrent battery charging while maintaining customer cost efficiency and system flexibility.

Key findings demonstrate that relatively modest daily budgets (2.0-4.0 DKK that is the cost of 1 kWh energy during peak times) achieve substantial peak reduction (47- 53%) in both pricing zones.The proposed dynamic import limit framework provides network operators with predictable tools for peak demand management whilst enabling complementary strategies such as incentive programs and demand forecasting. The decentralised approach ensures scalability through independent HEMS operation without centralised coordination constraints, whilst requiring only software updates to existing infrastructure for practical implementation. The transparent, voluntary financial framework promotes customer acceptance through fair compensation and rare budget limit occurrences, establishing sustainable long-term program viability.

Future research will focus on extending the framework to multi-device integration including EVs and heat pumps, whilst developing automated market mechanisms linking network operators with participating customers through local markets.

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