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Optimization problem for meeting distribution system operator requests in local flexibility markets with distributed energy resources

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HIGHLIGHTS

- We propose a new optimization problem for scheduling flexible resources to meet distribution system operator requests.
- We included loads, generators and batteries as flexibility resources.
- The optimization problem minimizes the SESP operation cost.
- We perform a case study to validate the work presented.
- We perform a test in the laboratory platform.

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ABSTRACT

The increasing penetration of distributed energy resources in the distribution grid is producing an ever-heightening interest in the use of the flexibility on offer by said distributed resources as an enhancement for the distribution grid operator. This paper proposes an optimization problem which enables satisfaction of distribution system operator requests on flexibility. This is a decision-making problem for a new aggregator type called Smart Energy Service Provider (SESP) to schedule flexible energy resources. This aggregator operates a local electricity market with high penetration of distributed energy resources. The optimization operation problem of SESP is formulated as an MILP problem and its performance has been tested by means of the simulation of test cases in a local market. The novel problem has also been validated in a microgrid laboratory with emulated loads and generation units. The performed tests produced positive results and proved the effectiveness of the proposed solution.

1. Introduction

Smart grids play a key role in the transformation of power systems. One of the main goals of the implementation of a smart grid is to integrate Distributed Energy Resources (DER) into the distribution grid to complement generation from bulk sources. Several benefits have been linked to the deployment of smart grids: reliability increase, carbon footprint reduction, increase in revenue and a decrease in consumer energy expenses [1]. However, the road to their successful implementation presents challenges at different levels: design, operation, control, energy storage technologies integration and regulatory issues [1].

Focusing on operational challenges, the evolution driven by smart grids is shaping a scenario with new energy exchanges. In this context, new actor and roles are materialising within the power system leading to new operational procedures.

A representative example is the appearance of the prosumer concept, which combines the consumer, storage and local level generator capabilities. These capabilities enable electricity and economic transactions in the so-called local electricity markets [2], also known as micro-markets in some studies [3,4]. In the near future, an energy exchange scenario can be envisioned with several geographically allocated local markets. Such markets managing flexible resources can address high penetration of DER at distribution grids [3].

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Recently published literature provides a wide variety of definitions of the flexibility in power systems [5,6]. In this paper, the following definition is adopted: Flexibility expresses the extent to which a power system can modify its electricity production and consumption in response to variability, expected or otherwise [7]. Additionally, upward regulation is defined as increasing generation or decreasing demand, and downward regulation means decreasing generation or increasing demand. Alizadeh et al. [8] classified flexibility effects on power systems chronologically as short-term, mid-term and long-term categories.

According to the Smart Energy Collective alliance definition [9], the role of Aggregator (AGR) consists of accumulating flexibility in active demand and supply. The AGR seeks the lowest costs to meet the energy demand of his portfolio taking the costs for capacity usage into account. Additionally, van den Berge et al. [10] and the Universal Smart Energy Framework (USEF) report [11] defined four flexibility customers: Distribution System Operators (DSO), Balance Responsible Parties (BRP), Transmission System Operators (TSO), and Prosumers. DSO and TSO are interested to purchase flexibility to manage grid congestions and reduce upgrading grid costs. BRP and retailers can use flexible resources to manage their portfolio and reduce deviation penalties and operation costs. Finally, prosumers can use their flexibility capabilities to reduce the electricity bill.

The paper is focused on flexibility in distribution grids with high penetration of renewable power generation and other distributed resources such as storage systems. The increasing amount of DER connected to distribution grids can compromise power quality in terms of voltage limit violations, line overloads or instabilities. Additionally, their variability can pose issues in grid operation due to voltage fluctuations, limiting the grid hosting capacity to integrate distributed generators [12,13]. Redundant transformers can avoid operating the grid close to its voltage limits, but the required expenses are considerable leading to the necessity of finding alternative solutions like storage [14] and demand response [15]. Furthermore, if some loads, distributed generators and batteries connected to distribution networks could operate according to grid necessities, DSO would manage networks avoiding these power quality issues. Hence, a local flexibility market (LFM) for distribution grid operation could provide the required trading environment avoiding additional investments. Moreover, in further developments not included in the present work, LFM will compensate local deviations due to forecasting errors reducing penalties in the wholesale markets and they will also participate in balancing markets managed by TSO.

The contents of this study are structured as follows. Section 2 includes the literature review about distribution grids with high penetration of DER. Section 3 describes the system under analysis and its architecture to identify the main actors and their interactions with the SESP. The optimization problem defined in this study, detailed in Section 4, is executed by the SESP to determine the system operation scheduling. The case study exposed in Section 5 shows the simulation results which are validated in a scaled experimental platform in Section 6. Finally, conclusions are drawn in Section 7.

2. Literature review

Following the recent contributions on the distribution network operation with high penetration DER, this section compares different solutions proposed in the literature. In order to compare different methodologies, Kok et al. [16] classified distribution-level energy management approaches in four categories: Top-down switching, centralized optimization, price-reactive and transactive energy systems. The present analysis is focused in two categories: local markets with a centralized approach and transactive energy systems. Classical demand response programs using a top-down switching methodologies and price reaction approaches are not included in the comparison because they use one-way communication system considering end-user as a passive actor.

2.1. Centralized local flexibility market approaches

Previous proposals presented approaches like Virtual Power Plants (VPP) that aims to emulate the behaviour of conventional generators aggregating DER [17,18]. First of all, Braun et al. [17] reviewed the aggregation approaches of DER comparing VPP with incentive-based indirect control systems. Pudjianto et al. [18] distinguished between commercial and technical VPP. Commercial VPP facilitates DER trading on wholesale markets and technical VPP provides services to support transmission system operation. Different authors proposed scheduling algorithms for VPP [19–23] Nevertheless, VPP are not end-user focused and they do not provide the framework for participants willing to be active traders with certain negotiation power. Alternative proposals like local markets and transactive energy systems are following the EU recommendation to put consumers at the heart of the energy markets by ensuring that they are empowered and better protected [24].

Comparing similar local market-based proposals to the present work, Kamyab et al. [25] exposed an optimization problem formulation to reduce the energy cost in energy community scheduling distributed energy resources (DER). Nguyen et al. [26] presented an optimization problem for BRP day-ahead portfolio management to compensate load and supply forecasting deviations. Finally, Torbaghan et al. [27] operated the local flexibility market to bid in wholesale markets. These three proposals are addressed at providing flexibility services to the BRP for portfolio management without receiving DSO requests.

Finally, Meese et al. [28] presented a case study for using flexibility to reduce the electricity bill from the prosumer perspective.

Previous works about constrained distributed grid operation like Eid et al. [29] and Verzijlbergh et al. [30] compared different frameworks for managing flexible resources to reduce network peaks but the corresponding operation formulation is not included. Esterl et al. [31] analysed the impact of flexibility on distribution grids without specifying the operation optimization problem. Esmat et al. [32,33] presented a similar problem using demand response but they assumed that activation decisions of each device are made by the DSO. Based on the queries to different European DSO in EMPOWER project, DSO are currently not interested in taking such decisions and they are more inclined towards simpler approaches without many interactions [34].

In contrast and from the DSO point of view, Spiliotis et al. [35] proposed a fix rate local flexibility market for managing flexible demands as a long-term planning tool for DSO. This aims to solve the expansion problem allocating flexibility needs and including grid expansion costs to alleviate grid constraints.

Moreover, Huang et al. [36] presented an optimal power flow algorithm to manage grid congestions using flexible resources. A similar approach is presented by Nguyen et al. [37] who considered that the DSO publishes the transformer capacity. Moreover, their proposal included a multiple AGR per transformer case assuming their availability to share information. However, not all consumers connected to the same distribution transformer have to be members of the same BRP and different BRP could not be interested to share information. Nevertheless, none of the two algorithms are applicable in the current European regulatory framework due to the current unbundling principle: there is a legal separation between network management and commercial activities [38]. Therefore, AGR and BRP are not allowed to know the grid parameters either grid status. That makes the inclusion of grid congestion constraints in the optimization problem not feasible in Europe. Moreover, DSO are not allowed to schedule flexible resources affecting the BRP portfolio balance.

In contrast in this work, AGR receives DSO requests without knowing grid status information to solve grid congestion problems in the daily basis. In order to attend its demands, AGR controls flexible assets using a market-based methodology.

2.2. Transactive energy approaches

Local markets are central platform-based systems which can be contrasted with similar approaches like Transactive Energy (TE) systems. The U.S. Department of Energy's Gridwise Architecture Council defined TE in [39] as a set of economic and control mechanisms that allows the dynamic balance of supply and demand across the entire electrical infrastructure using value as a key operational parameter.

Hu et al. [40,41] proposed a Transactive Energy (TE) system for managing constrained grids where DSO and Retailers negotiate to settle the congestion price. In the first version [40] authors presented a multi-period network-constrained TE method to integrate EV in distribution networks. The proposal advanced by authors in [41] requests a new agent called distribution-independent system operator to coordinate DSO and retailer's interest and operational conflicts but this new agent requires a new regulatory framework. Additionally, retailers need information about end-user grid bus connection and it could be not permitted in real implementations because it is considered confidential information by many DSO. Finally, the methodology proposed is very communication intensive because DSO and retailer iterate several times to find a feasible solution. In contrast, the present work proposes that the DSO is the first mover requesting flexibility and the SESP reacts based on this without any iterative process.

Other TE proposals are more user-focused and they rely on the assumption that every prosumer can trade its energy with a local intelligent controller or agent [16] but the balance responsibilities of every TE trader are not considered. At least, all transactions should happen in the same BRP portfolio. Moreover in the TE approach, communications are based on prices and energy quantities in a two-way negotiation. Therefore, consuming and producing devices communicate their energy preferences in terms of price and energy volume. Cintuglu et al. [42] proposed a methodology based on reverse auctions with multiple agents for local transactions and tested it by simulation and in laboratory environment.

2.3. TE and LFM comparison

This subsection compares benefits and drawbacks of TE and local markets for meeting DSO requests. The local market is a central platform-based system and it fits partially in the centralized optimization category with direct control signals. Nevertheless, flexibility contracts signed by end-users for each flexible device in local markets give them a strong decision power on local issues like TE do. Flexibility contracts specify available periods, cost per device and specific characteristics like control type.

Moreover, the system-level reaction is known when a response is triggered in centralized market-based methods [16], which is requested by DSO to ensure the appropriate response to attend their demands. In order to comply with DSO requests, TE user-focused approach could be less attractive for DSO because there is no central entity responsible for meeting the DSO request, and multiple negotiations are needed.

The main drawback of centralized approaches for meeting DSO needs is the scalability limit due to the communication system requested. Nevertheless, constrained situations will occur exceptionally and the communication system will be used occasionally. Additionally, the DSO problem will be located to a specific area and the communications requirements will be proportional to that.

Furthermore, the centralized approach with a single manager of the energy community for negotiations with the DSO, and its central trading platform, offers a simpler and more easy to implement interaction mechanism between DSO and AGR than TE approaches. Moreover, AGR as central entity can cut the maximum prices offered from flexibility sources to ensure stable flexibility prices.

Finally, the platform-based approach can be based on flexibility contracts and it does not need automatic trading agents.

3. Local flexibility market description and architecture

This section focuses on the local flexibility market description and architecture of the system under analysis. The main components, actors and their functions enabling the coordinated operation and control through the Smart Energy Service Provider (SESP) are presented. In order to facilitate a clear definition of the relationships between all the involved agents, components and their interactions, the system architecture definition is based on the Smart Gird Architecture Model (SGAM) developed by the standardization agencies CEN, CENELEC and ETSI to provide a common reference framework to develop smart grids [43].

In contrast to the previous studied works, this paper presents a novel and innovative proposal developing a local flexibility market-based operational problem of AGR or BRP to attend DSO requests scheduling flexible resources at short-term scale for real and feasible implementation in EMPOWER H2020 project and others under the current European regulatory framework. Additionally, the problem assumes existence of flexibility contracts as inputs from flexibility providers. The LFM operation problem formulated here is based on the market architecture and rules, and the new BRP agent called SESP defined by Ilieva et al. in [2]. Other activities related to the BRP operations in wholesale markets are not covered in this paper.

Furthermore and according to the Traffic Light Concept (TLC) proposed by the German Association of Energy and Water (BDEW) [44] and the study by Zoeller et al. [45], the present problem formulation is designed for situations where the DSO determined a yellow light situation in a grid zone and it wants to go back to the green light status. Thereafter, the DSO asks the SESP to apply corrective actions in exchange for economic compensation previously established on their contract. During yellow light situations, the DSO needs have maximum priority to avoid over-voltages or transformer over-loads and prosumers or ARG priorities are not considered.

The centralized approach is to increase the DSO confidence in the LFM ensuring that all participants will collaborate to recover the green light status. The SESP interacts with external agents like DSO and flexible resources through its Information and Communication Technology (ICT) trading platform, that has been designed and developed in the EMPOWER H2020 project [46–49]. The solution presented in this work for the grid constrained management problem is tested by simulation and validated in a laboratory environment.

3.1. Local flexibility market

A local flexibility market (LFM) is an electricity trading platform to sell and buy flexibility in geographically limited areas like neighbourhoods and small towns. The SESP is the local market platform provider and community aggregator (AGR). At the same time, the SESP is a BRP from the regulatory point of view because it bids in wholesale markets. In order to run these markets, local traders need the SESP Platform for sending information, trading for flexibility, and scheduling actions.

Fig. 1 shows a local flexibility market with four kind of agents:

- The DSO purchasing flexibility and giving the corresponding economic compensation.
- The SESP as market platform provider receiving flexibility offers and requests.
- Energy cooperatives and prosumers sending flexibility offers.

Energy cooperatives and prosumers offer their flexibility capabilities to the SESP platform competing for the corresponding revenues from DSO.

The flexibility market is executed in hours ahead time frames and its time schedule is shown in the Fig. 2. At the end of the day-before the operation, the DSO determines the flexibility need for the entire operation day. Based on the DSO request, the SESP can schedule flexible

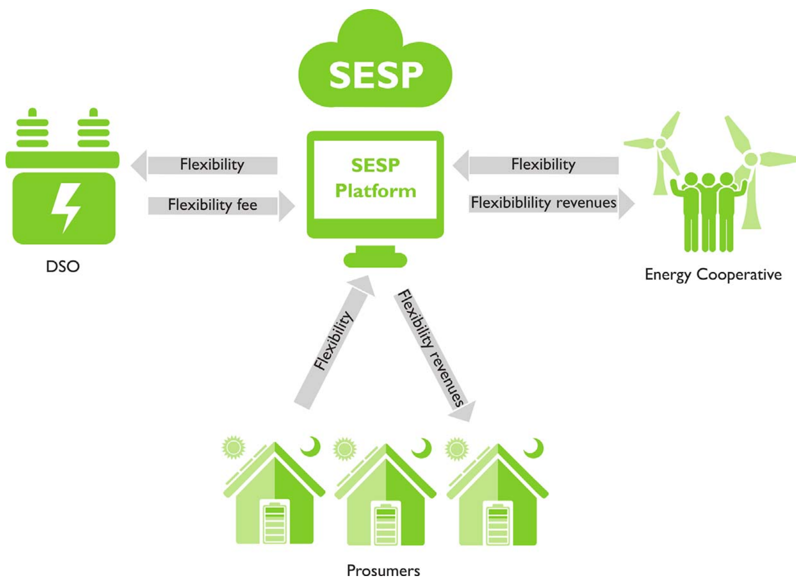


Fig. 1. Local flexibility market agents overview. Based on D2.2 of EMPOWER H2020 project [50].

resources optimally considering the entire operation day. In the EMPOWER Project, the LFM is executed at 11 p.m. and the period unit is quarter hour.

In this market, the flexibility providers sign contracts with the SESP specifying which resources offer flexibility, the price of using the offered flexibility and different constraints such as the day time when the flexibility can be used among others. The flexibility price is settled by the flexibility provider and it cannot be higher than the maximum price defined by the SESP. Low price flexible assets will be activated more often than high price ones. Additionally, flexibility providers are responsible for the change in their flexibility prices to adjust their particular comfort and profitability balance.

In order to avoid market dominance and over-costs, the flexibility revenues are paid-as-contract. As flexibility contracts can be updated periodically, daily and weekly modifications could be found. Due to the lack of experience from prosumers creating bids, the LFM is organized in pay-as-contract, a similar way like the so called pay-as-bid. The pay-as-clear approach would increase the cost of flexibility for the DSO because all providers would receive the clearing price, and for all society at the end.

Flexibility contracts specify the activation cost per flexible load. Therefore, consumers can assign lower prices to less valued loads and they can be more flexible if the reward is higher. Fig. 3 exemplifies a consumer flexibility offer based on its contract with four flexible

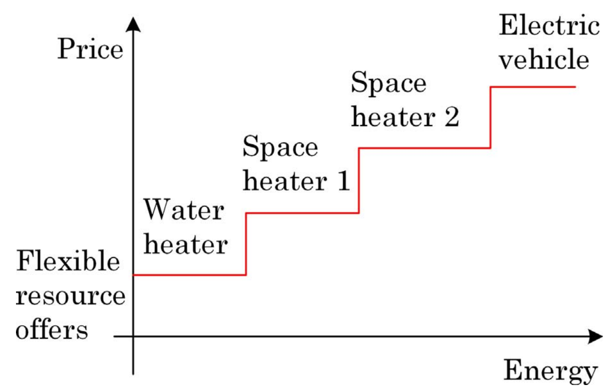


Fig. 3. Consumer's flexibility offers example.

resources sorted from the cheapest offer to the most expensive one, which are a water heater and an electric vehicle respectively.

Therefore, according to the DSO requirements to manage power quality issues, the SESP decides which resources are necessary to meet the request and sends the control signals to them. After that, the participants with activated resources are then rewarded based on their flexibility contract. Following the previous flexibility definition, the activated flexibility of each resource is measured with the following steps:

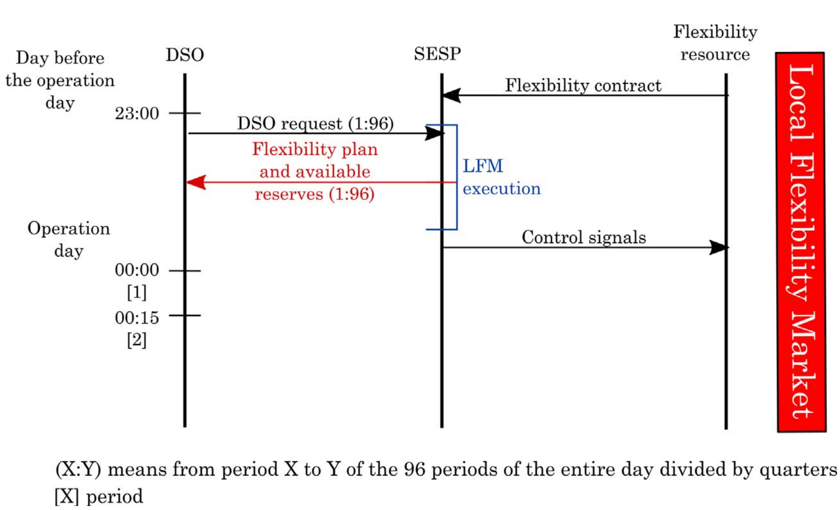


Fig. 2. Local flexibility market timeline. Based on D6.3 of EMPOWER H2020 project [34].

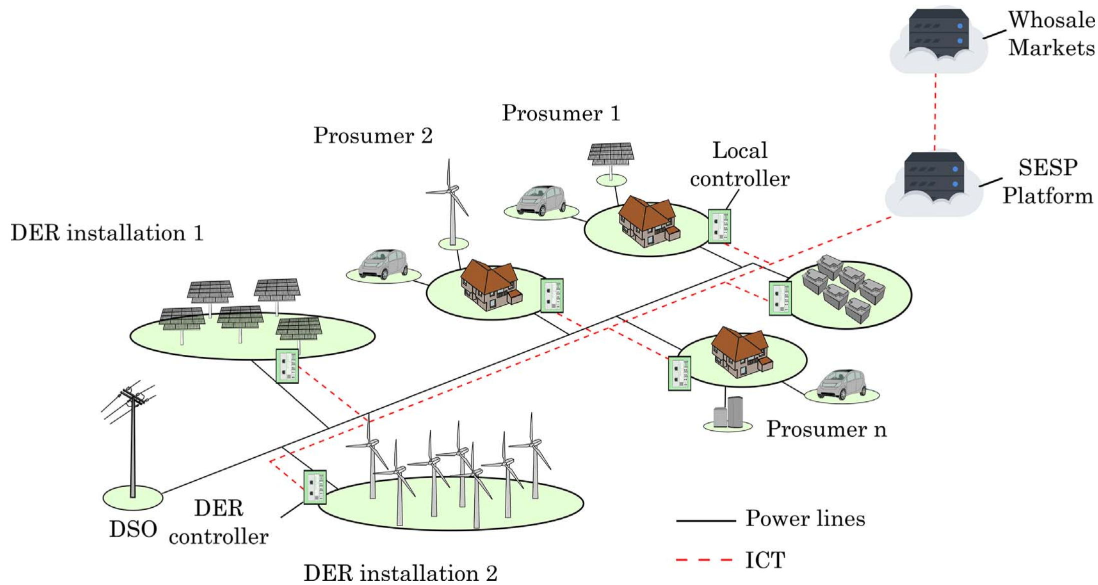


Fig. 4. System description.

1. The consumption or generation forecast of every flexible asset is done by the SESP and it needs the approval of the DSO to be used as the base line scenario.
2. Once the SESP sends a command to a flexible resource in order to modify its generation/consumption, the amount of the activated flexibility is counted as the absolute value of the difference between the predicted power consumption/generation and the measured power in the device metering point.
3. The activation of the flexibility ends when the SESP sends an *END* command permitting the resource to operate freely again.

Finally, it must be taken into account that the LFM presented in this work is limited to provide flexibility to DSO.

3.2. System under analysis

The electric system analysed covers LV (Low Voltage) and MV (Medium Voltage) distribution grid and includes prosumers installations and DER facilities, as depicted in Fig. 4. The main actors involved are prosumers, DER's owners, the DSO and the SESP. Many prosumers can be grouped forming a community, which can be understood as another actor. Prosumers, DERs and energy communities offer flexibility to the system and, in return, can be rewarded based on flexibility contracts and SESP decisions. In order to participate in the local market they have to install a local controller (LC) in every participant house in order to receive and apply the SESP control signals.

LC are small computers with communication capabilities for households to monitor and control production, flexible consumption and storage if they are available. Every LC communicates with the SESP Platform to report the energy resource status. Moreover, LC takes decisions autonomously and send control signals to every resource smart plug at the prosumer level. For example, the water heater smart plug receives control signals from the LC and disconnects it.

Local controllers can take decisions during non-constrained situations about the energy management of the household resources. Nevertheless, during grid constrained situations like yellow and red light, the SESP and the DSO can send direct control signals respectively avoiding the local decisions.

3.3. LFM architecture

SGAM methodology [43] proposes a three-dimensional representation of smart grids, separating smart grid zones, domains and interoperability layers. Based on this conceptualisation, the local market interoperability component layer is depicted in Fig. 5 to identify components of each zone and domain. The zones layer splits the smart grid into five activities: process, station, operation, enterprise and market activities. In contrast, domain layer distinguished between distribution, DER and customer premises.

The domains affected cover from prosumers and DER installations up to the distribution grid. The zones identified as Market and Enterprise comprise three subsystems that make SESP operation possible. They are the market, control and metering systems. The market is responsible for the management of transactions needed to implement the local flexibility market. It covers energy scheduling, flexibility, settlement, billing and accounting applications. The control subsystem is in charge of the management of the orders determined in the market. The metering subsystem manages the data resulting from smart meters (SM) and local controllers (LC) on the field zone. They allow to connect the SESP with the Process zone, where the electricity transactions take place. The SESP information exchanges with these field elements can be direct with prosumers. In contrast, communications with DER premises go through a Supervisory control and data acquisition (SCADA) system in the Operation zone.

The communication, information and function interoperability layers reflecting specificities like the communication protocols used are explained by Bullich-Massagué et al. in [46].

The utilization of local controllers on every storage, household and generation unit could compromise the system scalability. However, the recent developments of Big Data techniques will improve the LFM operation in large scale systems. Additionally, the utilization of direct control signals from the SESP platform could compromise the cyber-pysical security [51,52] but the recent developments of cyber-security techniques will be included in further LFM developments [53]. Finally, the economic feasibility of the entire system depends on the potential benefits of the LFM operation. Alternative approaches are under consideration like sharing a LC per group of households but economies of scale would help to reduce LC costs. Furthermore, this is an open research question that will be answered in further works based on the pilot experience.

4. Local flexibility market problem formulation

The local flexibility market problem presented in this section is an

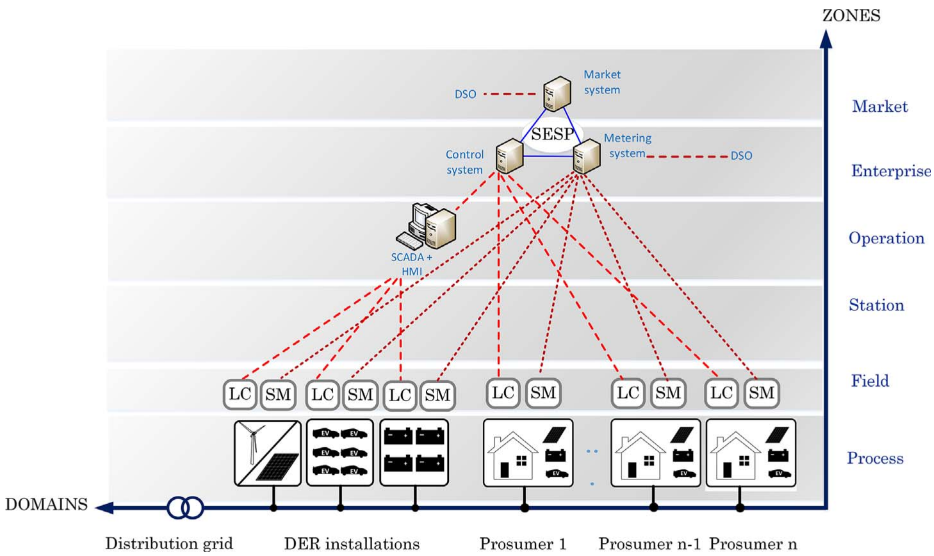


Fig. 5. System architecture based on SGAM.

extension of the one explained by Ottesen in [54] for operating building energy systems with flexible resources and minimizing the electricity cost. The novelty of the present approach is to include the functionality to activate flexibility under DSO requests operated in a local flexibility market framework with a SESP as BRP and local market operator simultaneously. Additionally, local market participants are active traders deciding on their flexibility price. Previous approaches mentioned assumed to have information about the current status of the grid but this is not possible in the near future. Therefore, the presented model is closer to the current regulatory framework. Additionally, the presented optimization problem will be implemented in the EMPOWER H2020 pilots. As Ottesen in [54], in the current study it is assumed that local controllers receive direct control signals from the SESP and the problem is formulated as an mixed-integer linear programming (MILP).

The formulated problem assumes that a baseline is an agreed parameter between the SESP and the DSO. According to the New York Independent System Operator report [55], *"A baseline is the estimated amount of energy use expected by a facility if a load reduction had not occurred in response to the NYISO instruction or schedule "*. The same concept is applied for the present study, the baseline is the scenario in the absence of the SESP agent.

The optimization problem description is divided in different subsections: Objective function, flexibility sources models, and DSO request constraints. This approach includes the following flexibility sources: flexible generators, batteries and flexible loads.

4.1. Objective function

The objective function shown in Eq. (1) reflects the minimization of the SESP's operation cost of meeting a request from the DSO during the following periods. Each flexibility cost (P) comes from the SESP-community member contract and it is predefined before the operation phase. All sets, parameters and variables are explained as they appear and are listed in the Appendix A.

The majority of cost parameters can be different every period t to consider cost fluctuations. In contrast, prices for flexible loads are constant during the operation day to facilitate the customer participation to the LFM. The time resolution t is a flexible parameter in the problem. In the EMPOWER system and the case study, it is defined as 15 min because is the smallest resolution of the current balancing markets.

The objective function can be decomposed in different flexibility costs:

- $P^{Gr}_{g,t}{\cdot}\chi^{Gr}_{g,t}$: cost of reducing generation output of the unit $g \in G^r$ during period t
- $P^{Gd}_{g,t}{\cdot}\chi^{Gd}_{g,t}$: cost of disconnecting the generator $g \in G^d$ during period t
- $P^{B,in}_{b,t}{\cdot}\sigma^{in}_{b,t}, P^{B,out}_{b,t}{\cdot}\sigma^{out}_{b,t}$: cost of charging or discharging the battery unit b during period t, respectively
- $P^{CD}_{k}{\cdot}(\delta^{start}_{k,t} + \delta^{run}_{k,t})$: cost of switching off the curtailable disconnectable load $k \in K^{CD}$ during period t
- $P^{SP}_{k}{\cdot}(\rho_{k,c} - V^{start}_{k,c})$: cost of shifting $\rho_{k,c} - V^{start}_{k,c}$ periods the shiftable load $k \in K^{SP}$ during shifting period c

Notice that the cost for using flexibility from curtailable and shiftable loads is not dependent of the energy activated. This approach avoids disputes after the operation day, to determine the economic compensation for the activated flexibility.

The variables included in the objective function are the flexibility to be activated of each resource at each period. They can be used to calculate the corresponding control signals after executing the LFM operation problem. For instance, the reducible photovoltaic generators must receive a setpoint signal based on the difference between the current production and the flexibility activated.

$$\min f^{LFM}_{obj} = \sum_{t\in T} \Big(\sum_{g\in G^r} P^{Gr}_{g,t}\chi^{Gr}_{g,t} + \sum_{g\in G^d} P^{Gd}_{g,t}\chi^{Gd}_{g,t} + \sum_{b\in B} (P^{B,in}_{b,t}\sigma^{in}_{b,t} + P^{B,out}_{b,t}\sigma^{out}_{b,t}) + \sum_{k\in K^{CD}} P^{CD}_{k}{\cdot}(\delta^{start}_{k,t} + \delta^{run}_{k,t})\Big) + \sum_{k\in K^{SP}} \sum_{c\in C} P^{SP}_{k}{\cdot}(\rho_{k,c} - V^{start}_{k,c}) \tag{1}$$

This objective function is subject to the following constraints:

4.2. Flexible generator model

Flexible generation installations with remote control capability can provide downward regulation during periods of energy surplus. There are two types of curtailable generators: reducible ($g \in G^r$) and disconnectable ($g \in G^d$). Reducible generators can receive control signals of energy production adjusting their power output during a specific period of time. In contrast, disconnectable generators are those that can only be switched on and off and they cannot receive setpoints.

The decision variables for reducible and disconnectable production are $\chi^{Gr}_{g,t}$ and $\chi^{Gd}_{g,t}$ respectively and they represent the amount of active energy curtailed.

Eq. (2) limits the energy flexibility supplied by generation g during period t up to its forecasted production $F^{G}_{g,t}$. Additionally, the disconnectable generation constraint of Eq. (3) includes a binary variable

($\delta_{g,t}^{G}$) to define if the generator g is disconnected or not during period t.

$$0 \leqslant \chi_{g,t}^{Gr} \leqslant F_{g,t}^{G} \quad \forall\ g \in G^{r}, \forall\ t \in T \tag{2}$$

$$0 \leqslant \chi_{g,t}^{Gd} = \delta_{g,t}^{G} \cdot F_{g,t}^{G} \quad \forall\ g \in G^{d}, \forall\ t \in T \tag{3}$$

where $\chi_{g,t}^{Gr}$ and $\chi_{g,t}^{Gd}$ represent the flexibility activated and their setpoints are the difference between the forecasted production and the flexibility requested.

The cost of curtailing a generator is a fee established in the agreed flexibility contract. Particularly, it is defined the price of reducing or disconnecting energy generation, period by period, and is represented by $P_{g,t}^{Gr}$ and $P_{g,t}^{Gd}$ respectively.

4.3. Battery model

Electricity storage units can provide up and down regulation discharging or charging energy respectively. This model divides the energy charging and discharging decision variables in $\sigma_{b,t}^{in}$ and $\sigma_{b,t}^{out}$ correspondingly. These variables define the energy setpoint of each battery unit b during each period t. State-of-charge Eq. (4) considers the round-trip efficiency each time that battery unit b delivers (η_{b}^{out}) or stores electricity (η_{b}^{in}).

$$\sigma_{b,t}^{soc} = \sigma_{b,t-1}^{soc} + \sigma_{b,t}^{in}\eta_{b}^{in} - \frac{\sigma_{b,t}^{out}}{\eta_{b}^{out}} \quad \forall\ b \in B, \forall\ t \in T \tag{4}$$

Battery constraints Eqs. (5) and (6) limit the maximum energy charged or discharged by batteries per period according to their specified in energy capacity (Q_{b}^{in},Q_{b}^{out}). Moreover, Eq. (7) ensures that the maximum storage capacity (O_{b}^{max}) is not exceeded.

Finally, the initial battery state-of-charge must be introduced in the model (SOC_0).

$$\sigma_{b,t}^{in} \leqslant Q_{b}^{in} \quad \forall\ b \in B, \forall\ t \in T \tag{5}$$

$$\sigma_{b,t}^{out} \leqslant Q_{b}^{out} \quad \forall\ b \in B, \forall\ t \in T \tag{6}$$

$$\sigma_{b,t}^{soc} \leqslant O_{b}^{max} \quad \forall\ b \in B, \forall\ t \in T \tag{7}$$

In this formulation, the day-ahead market price is used as a reference for optimizing the acquisition in the intraday market where the energy is meant to be finally bought. Additionally, batteries with dedicated smart meters are spread in the distribution grid to attend local grid constraints and they are owned by the SESP. Therefore, the cost for charging batteries ($P_{b,t}^{B,in}$) is the summation of the DA market price and the grid tariff cost.

Later on, the cost of discharging batteries ($P_{b,t}^{B,out}$) is set according to their the lifespan reduction value for the whole charging and discharging process, and the SESP opportunity cost to use the battery for future needs. In further developments, the ownership of batteries will be studied in depth.

4.4. Flexible loads model

Following the CENELEC classification [56], flexible loads can be divided in buffered and non-buffered loads. Buffered loads typically have thermal inertia and the consumption can be moved backward or forward. In contrast, non-buffered loads cannot store electricity increasing the consumption profile. The LFM operation problem presented in this paper considers non-buffered flexible loads (K) and they can be subdivided in two categories: curtailable disconnectable (CD), when the consumption is interrupted and non-recovered, and shiftable profile (SP), which can be postponed without changing the consumption profile.

Fig. 6 shows this distinction and compares the result of the same signals on both types. As soon as a disconnection order is received, both CD and SP loads disconnect. But the difference occurs when the order ends. In this case, CD loads follow the baseline profile while SP loads applies the curtailed profiles.

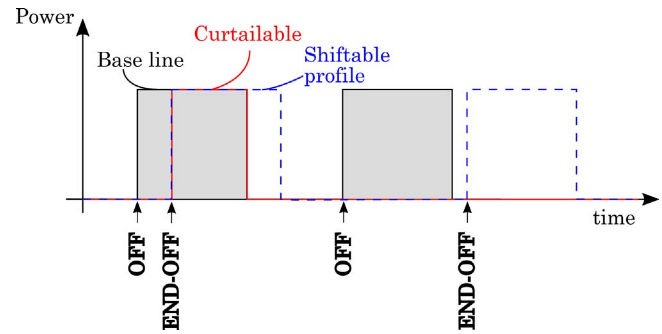


Fig. 6. Comparison of two flexible loads type behaviour under the same command signals.

4.4.1. Curtailable disconnectable load model

Curtailable disconnectable loads (K^{CD}) are those flexible loads that do not consume the curtailed energy once they are reconnected. CD loads can be for example programmable space heaters with a scheduled consumption. If the reconnection signal arrives out of the time program, the control signal will not switch the load on.

They are remotely controlled with binary signals *OFF* ($\delta_{k,t}^{start}$) and *END-OFF* ($\delta_{k,t}^{end}$). When an *OFF* order ($\delta_{k,t}^{start} = 1$) is sent to the curtailable load k, independently of the baseline status, the load is switched off. When the load receives an *END-OFF* order ($\delta_{k,t}^{end} = 1$), the load goes back to the baseline consumption profile. Additionally, the time between the OFF and END-OFF signals is calculated using the binary variable $\delta_{k,t}^{run}$.

For example, if the *OFF* signal is 1 during period $t = 2$ ($\delta_{k,2}^{start} = 1$) and the *END-OFF* signal is 1 during period $t = 8$ ($\delta_{k,8}^{end} = 1$), then $\delta_{k,t}^{run}$ is 1 between $t \in [3,7]$.

Regarding the *END-OFF* control signal, all signals in this model are actions at the beginning of the period. Then, the *END-OFF* signal means to reconnect the load at the beginning of the period if the baseline forecasted to consume.

In order to ensure the appropriate curtailment decision, the model includes the following constraints.

Eqs. (8) and (9) avoid simultaneous actions during the same period. Eq. (8) prevents simultaneous curtailment and disconnection of the load k. Similarly, Eq. (9) ensures that load is disconnected or reconnected during period t.

$$\delta_{k,t}^{start} + \delta_{k,t}^{run} \leqslant 1 \quad \forall\ k \in K^{CD}, \forall\ t \in T \tag{8}$$

$$\delta_{k,t}^{start} + \delta_{k,t}^{end} \leqslant 1 \quad \forall\ k \in K^{CD}, \forall\ t \in T \tag{9}$$

Continuity constraint (Eq. (10)) ensures that once the load is disconnected ($\delta_{k,t-1}^{start} = 1$) or running up ($\delta_{k,t-1}^{run} = 1$), it can only remain disconnected ($\delta_{k,t}^{run} = 1$) or be reconnected ($\delta_{k,t}^{end} = 1$).

$$\delta_{k,t-1}^{start} + \delta_{k,t-1}^{run} = \delta_{k,t}^{run} + \delta_{k,t}^{end} \quad \forall\ k \in K^{CD}, \forall\ t \in T \tag{10}$$

Flexibility contracts allow defining the maximum number of disconnection orders (N_{k}^{max}) per day that a flexible load can receive and constraint shown in Eq. (11) includes this functionality.

$$\sum_{t=1}^{T} \delta_{k,t}^{start} \leqslant N_{k}^{max} \quad \forall\ k \in K^{CD} \tag{11}$$

Additionally, constraint 12 includes the capability to assure the minimum resting time (D_{k}^{min}) between load disconnections.

$$\delta_{k,t}^{end} + \sum_{i=t}^{t+D_{k}^{min}-1} \delta_{k,i}^{start} \leqslant 1 \quad \forall\ k \in K^{CD}, \forall\ t \in T \tag{12}$$

Finally, flexibility contracts can include the possibility to define the maximum disconnection duration (D_{k}^{max}). The corresponding constraint is shown in 13.

$$\sum_{i=t}^{t+D_k^{max}} \delta_{k,i}^{end} \geqslant \delta_{k,t}^{start} \quad \forall\, k \in K^{CD}, \forall\, t \in T \tag{13}$$

The cost of disconnecting load k is the number of periods disconnected times its disconnection fee (P_k^{CD}).

4.4.2. Shiftable profile load model

Shiftable profile loads (K^{SP}) are those that postpone the consumption keeping the same profile. Additionally, they consume as soon as possible. Therefore, the routine must start sending the *END* signal if the load has to be shifted forward. It is assumed that it is not possible to split the energy profile. Those loads can be for example dish washers, washing machines, dryers, electric water heaters, heat pumps, and electric vehicle chargers because the profile will be exactly the same whenever they receive an *END-OFF* signal.

Due to the need to schedule flexible resources the day before, it is assumed that there is no information available apart from the contracts and data from previous experiences. Then, this model relies on the SESP forecasting system capable to foresight the consumption by requesting a minimum information from the end-user. Decisions on real time operations are left for further developments.

The shiftable profile (SP) model consists in defining a framework to operate shiftable loads. Therefore, it is used to decide the new energy profile for each appliance k within its shiftable periods allowed by the user. Different shiftable periods for the same appliance are indexed with c and they allow only one shift. SP model is used to define when to activate upward and downward regulation by sending the *END-OFF* signal ($\rho_{k,c}$). SESP determines the new load consumption profile ($\omega_{k,t}$) of each period t accordingly.

Flexibility contract defines the shiftable period c for each appliance k with the parameters $T_{k,c}^{start}$ and $T_{k,c}^{end}$ which determine the time span in which is possible to schedule consumption. Within this shiftable period c, the forecasted consumption is denoted with $V_{k,c}^{start}$ and $V_{k,c}^{end}$ representing the beginning and ending of the energy profile in the base case.

Additionally, $\gamma_{k,t}$ is the binary variable which indicates the *END-OFF* signal. For example, $\gamma_{k,t^*} = 1$ if $\rho_{k,c} = t^*$ being t^* the period to send the *END-OFF* signal.

Fig. 7 shows an example case with shiftable period $T_{k,c}^{start} = 2$ and $T_{k,c}^{end} = 13$, and with base profile ($W_{k,t}^{SP}$) in black which begins at $V_{k,c}^{start} = 2$ and ends at $V_{k,c}^{end} = 7$. The corresponding decision variables for shiftable load k during shifting period c are $\gamma_{k,t} = 1$ for $t = 8$, $\rho_{k,c} = 8$ and the corresponding $\omega_{k,t}$ is the shifted profile in grey.

This model is limited to shift forward the entire profile because it is assumed that these loads consume as soon as they can. Therefore, the base case is already the earliest period when they can consume.

Eq. (14) ensures that the shiftable load is scheduled within the shiftable period ($T_{k,c}^{start}$,$T_{k,c}^{end}$), even if the load is not postponed ($\rho_{k,c} = V_{k,c}^{start}$).

$$\sum_{d=T_{k,c}^{start}}^{T_{k,c}^{end}-(V_{k,c}^{end}-V_{k,c}^{start})} \gamma_{k,d} = 1 \quad \forall\, k \in K^{SP}, \forall\, c \in C(k) \tag{14}$$

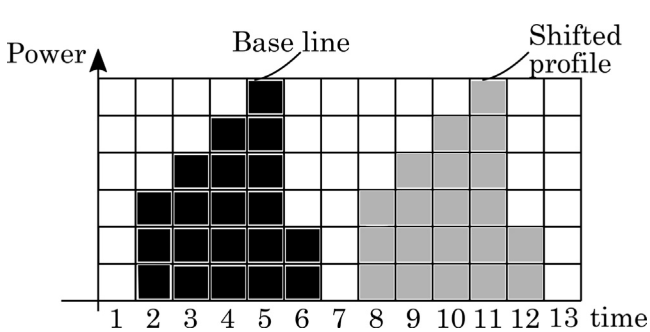


Fig. 7. Illustration of a shiftable profile load.

Eq. (15) ensures that the new load profile ($\omega_{k,t}$) consumes the same power as the baseline load ($W_{k,t}^{SP}$).

$$\omega_{k,t} = \sum_{n=0}^{T_{k,c}^{end}-T_{k,c}^{start}} \gamma_{k,t-n}\cdot W^{SP}_{k,(T_{k,c}^{start}+n)}$$
$$\forall\, t \in [T_{k,c}^{start},T_{k,c}^{end}], \forall\, k \in K^{SP}, \forall\, c \in C(k) \tag{15}$$

Once the new profile is established, Eq. (16) defines the starting period ($\rho_{k,c}$) to calculate the corresponding flexibility cost of load k in shifting period c in the objective function. The cost for shifting the load k is defined by the consumption delay ($\rho_{k,c}-V_{k,c}^{start}$) times the cost per time unit (P_k^{SP}) settled in its flexibility contract.

$$\rho_{k,c} = \sum_{t=T_{k,c}^{start}}^{T_{k,c}^{end}-(V_{k,c}^{end}-V_{k,c}^{start})} \gamma_{k,t}\cdot t \quad \forall\, k \in K^{SP}, \forall\, c \in C(k) \tag{16}$$

4.5. DSO request constraints

Finally, DSO constraints represent the request for fulfilling upward and downward regulation. These constraints are defined as the minimum required amount of active energy variation with respect to the forecasted baseline scenario and are denoted as D_t^{DSO}. Positives and negative values of D_t^{DSO} mean upward and downward regulation respectively.

Eqs. (17) and (18) are constraints that ensure that flexible resources comply with the DSO upward and downward regulation request respectively. All flexibility resources are included in both equations because they can be in favour or against the request.

During up-regulation periods ($t \in T^+$) defined as positive DSO requests ($D_t^{DSO} > 0$), controllable resources are batteries delivering active energy ($\sigma_{b,t}^{out}$), disconnectable loads ($W_{k,t}^{CD}\cdot(\delta_{k,t}^{start} + \delta_{k,t}^{run})$), and shiftable loads ($W_{k,t}^{SP}-\omega_{k,t}$). Additionally, down-regulation resources like reducible and disconnectable generators ($\chi_{g,t}^{Gr}$,$\chi_{g,t}^{Gd}$) and batteries storing energy ($\sigma_{b,t}^{in}$) are included in the up-regulation constraint to include the possibility of discharging batteries for further needs or disconnecting generators for other reasons.

$$\begin{aligned}&\textstyle\sum_{b\in B}\sigma_{b,t}^{out} + \sum_{k\in K^{CD}} W_{k,t}^{CD}\cdot(\delta_{k,t}^{start} + \delta_{k,t}^{run})+\\ &\quad \textstyle\sum_{k\in K^{SP}} (W_{k,t}^{SP}-\omega_{k,t})-\sum_{g\in G^r}\chi_{g,t}^{Gr}- \qquad \forall\, t \in T^+\\ &\quad \textstyle\sum_{g\in G^d}\chi_{g,t}^{Gd}-\sum_{b\in B}\sigma_{b,t}^{in} \geqslant D_t^{DSO}\end{aligned} \tag{17}$$

For each downward regulation period ($t \in T^-$), defined as negative request ($D_t^{DSO} < 0$), the upward and downward flexibility resources have negative and positive sign respectively in Eq. (18).

$$\begin{aligned}&\textstyle\sum_{g\in G^r}\chi_{g,t}^{Gr} + \sum_{g\in G^d}\chi_{g,t}^{Gd} + \sum_{b\in B}\sigma_{b,t}^{in}+\\ &\quad \textstyle\sum_{k\in K^{SP}} (\omega_{k,t}-W_{k,t}^{SP})-\sum_{b\in B}\sigma_{b,t}^{out}- \qquad \forall\, t \in T^-\\ &\textstyle\sum_{k\in K^{CD}} W_{k,t}^{CD}\cdot(\delta_{k,t}^{start} + \delta_{k,t}^{run}) \geqslant -D_t^{DSO}\end{aligned} \tag{18}$$

Notice that reconnection of SP loads in Eq. (18) has the opposite sign than in Eq. (17) because the new SP consumption was not included in the baseline previously. Therefore, the SP load is considered as downward source when it is shifted to down regulation periods. In contrast, CD loads are not supplying downward regulation because they cannot consume out of the baseline.

5. Case study

In order to test the proposed problem, this section introduces a case study that includes all implemented functionalities in the problem formulation. Additionally, this section exposes the results obtained during the simulation process in order to define the control signals.

The optimization problem is validated using the high-level Julia programming language and JuMP. JuMP is an open source algebraic modelling language for linear, quadratic, and non-linear constrained

Table 1
Case study flexible resources portfolio and characteristics.

House	Resource	ID	Power [W]	Flexibility periods	Control type	Price
1	Load-CD	1	2000	All day	on/off	0.1
1	Load-CD	2	2200	6:00–18:00	on/off	0.3
1	Load-CD	3	3200	10:00–15:00	on/off	0.5
1	Load-CD	4	1000	08:00–20:00	on/off	0.7
1	Load-CD	5	1500	Weekend	on/off	0.9
1	Load-CD	6	3100	05:00–22:00	on/off	1.1
1	Load-CD	7	2300	Weekend	on/off	1.3
1	Load-SP	1	2000	Weekend	shiftable	0.5
1	Load-SP	2	2000	Weekend	shiftable	0.7
1	Load-SP	3	2000	Weekend	shiftable	0.9
1	PV	1	3100	All day	reducible	1.5
1	PV	2	3100	All day	reducible	1.7
2	Load-CD	8	3000	All day	on/off	2.1
2	Load-CD	9	2100	00:00–07:00	on/off	2.3
2	Load-CD	10	1200	All day	on/off	2.5
2	Load-CD	11	1800	All day	on/off	2.7
2	PV	1	3100	All day	disconnectable	2.9
3	Load-CD	12	3000	All day	on/off	3.1
3	Load-CD	13	1200	All day	on/off	3.3
3	Load-CD	14	2000	09:00–17:00	on/off	3.5
3	Load-CD	15	2000	09:00–17:00	on/off	3.7
3	Load-CD	16	1600	07:00–15:00	on/off	3.9
3	Load-CD	17	2500	Weekend	on/off	4.1
3	Load-CD	18	3700	Weekend	on/off	4.3
3	Load-SP	4	2000	All day	shiftable	1.1
3	Load-SP	5	2000	All day	shiftable	1.3
3	PV	2	3100	All day	disconnectable	4.5
4	Load-CD	19	2000	All day	on/off	4.9
4	Load-CD	20	1200	08:00–00:00	on/off	5.1
4	Load-CD	21	1800	08:00–14:30	on/off	5.3
4	Load-CD	22	2300	All day	on/off	5.5
4	Load-CD	23	2300	06:30–22:30	on/off	5.7
4	PV	3	3100	All day	disconnectable	5.9
SESP	Battery	1	3000	All day	full	1.9
SESP	Battery	2	3000	All day	full	4.7

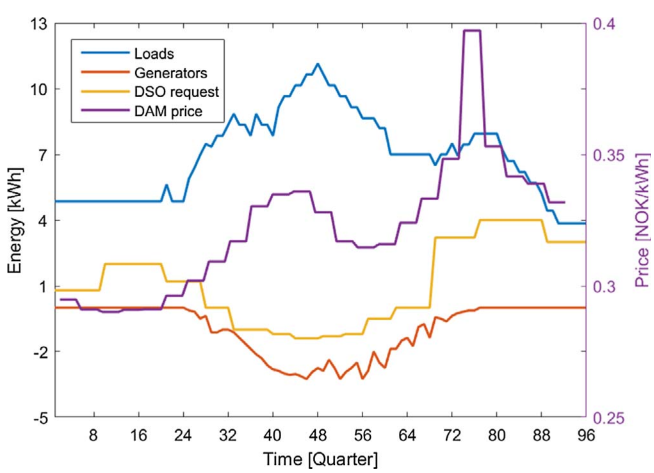


Fig. 8. Energy charging prices during the case study day.

optimization problems embedded in Julia [57,58]. The solver used was the Coin-Branch & Cut (CBC) in a computer with i7-6600 CPU 2.60 GHz and 16.0 GB RAM memory, and the problem took 8.084 s to find the case study optimal solution considering 0.2% of maximum error.

5.1. Scenario description

The case study illustrates with figures a small scale LFM composed by four households with DER listed with their characteristics in Table 1. Loads are typically space and water heaters that can be disconnected

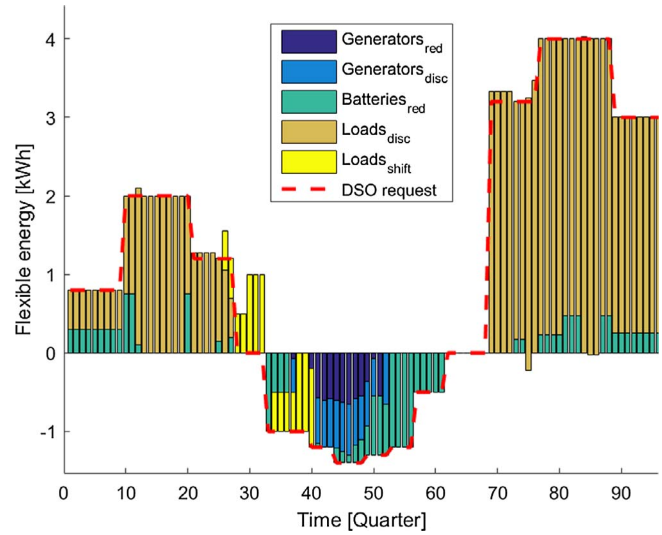


Fig. 9. Flexibility control signals aggregated by source type.

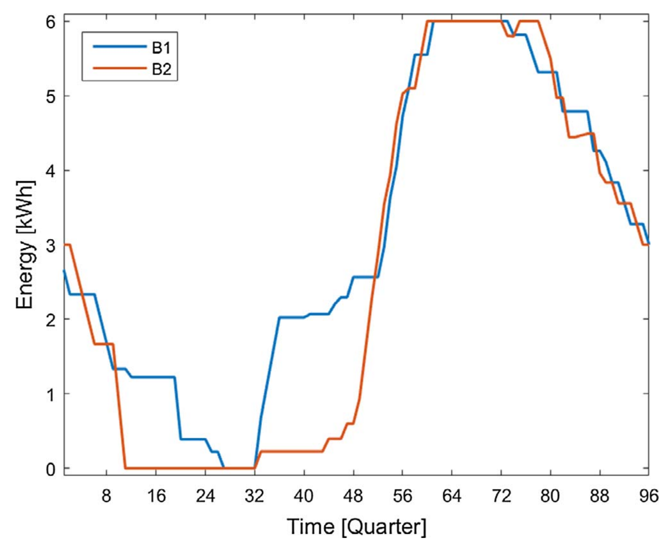


Fig. 10. Batteries state-of-charge evolution.

within the flexibility contract constraints. Local generators are photovoltaic (PV) panels installed in the rooftops of households. Two of them can be remotely controlled setting their setpoints and others only can be remotely disconnected. Batteries can be fully controlled remotely.

Load and generation profiles are from winter and summer data respectively to show up all capacities of the formulated problem during a single day. That contains different consumption and generation behaviour. The case is a weekday and resources for weekend are not available during this time horizon.

In this case study, flexibility prices for each load are constant during the operation day and sorted in ascending order for the sake of clarity. According to the Section 4.1, the cost for activating flexible loads is not dependent of the activated energy and it is quantified in NOK/period. In contrast to flexible loads, flexible generators are quantified per energy activated as NOK/kW h because the flexibility activated is time dependent and related, for example, to solar radiation. Additionally, flexibility prices for generators are also constant during the day and higher than load prices.

Battery charging prices are from the DA market. In the case study, the prices are from the Elspot market from NordPool of 30/10/2016 in the Oslo area NO1, and it is the same price for all batteries which varies from [290.05, 397.11] NOK/MWh and they are represented in Fig. 8.

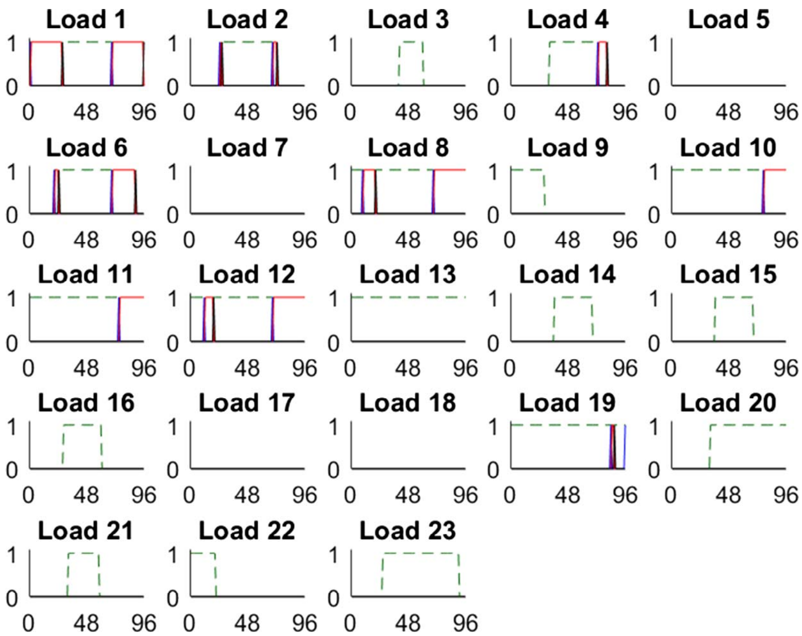


Fig. 11. Control signals sent to flexible loads.

During 2016, the average exchange rate for EUR and NOK has been 9.2906 NOK/EUR according to the European Central Bank [59] In contrast, prices for discharging are constant because they only include the degradation of battery according to end-user criteria and they are included in the Table 1.

Additionally, Fig. 8 shows the aggregated flexible loads forecasted profile ($W_{k,t}^{CD} + W_{k,t}^{SP}$) with a maximum demand of 11.15 kW h during period 48. Generation forecasting ($F_{g,t}^{Gr} + F_{g,t}^{Gd}$) of all units has a peak during period 52 of 3.25 kW h. The D^{DSO} is the DSO request for the operation day. In the case study, the available flexibility is larger than the DSO need for all periods. Therefore, SESP has to execute the LFM to allocate the cheapest flexible resources considering the problem constraints. If the SESP has not enough resources, it cannot attend the DSO request completely.

The time periods used in this case study are quarter hour and the time horizon is one day. The SESP algorithm is executed once per day before the operation day begins. Previously, the DSO has sent its flexibility needs. Furthermore, this case study has a deterministic approach to clearly explain the operation procedure. In further developments, it can manage parameters with uncertainty such as $F_{g,t}^{Gr}, F_{g,t}^{Gr}, W_{k,t}^{CD}, W_{k,t}^{SP}, V_{k,c}^{start}, V_{k,c}^{end}$.

This SESP algorithm does not apply corrective actions based on field data but the local flexibility market could include such capability.

Fig. 9 shows the total flexibility request by the DSO (D^{DSO}) and which flexible resource is providing up or down regulation.

Flexibility is quantified in energy (kW h) and it is based on the forecasted values. During the up-regulation periods, the DSO request is compensated by disconnecting loads and discharging batteries and shifting loads. In contrast, the down-regulation request is compensated reconnecting shiftable loads, charging batteries, and disconnecting or reducing photovoltaic generators. Additionally, between up- and down-regulation periods regulations are not needed. Nevertheless, the shiftable loads are disconnected in order to be connected during the down-regulation period.

Fig. 10 shows the state-of-charge (SOC) evolving from a 50% status and 3 kW h per battery to 0% to support the up-regulation request. After that, charging up to 100% and 6 kW h per battery during down-regulation storing energy from PV panels and discharging such energy during the night. This case study begins the simulation day with 50% of SOC and includes a constraint to end the simulation horizon with the same amount of energy from the beginning to compensating the storage units effect on the objective function introducing free energy.

Fig. 11 exposes the disconnection (*OFF*) and reconnection (*END-OFF*) binary signals sent to flexible loads in blue and black respectively. Additionally, the read line represents the period when the CD load is not consuming and the green line is the baseline ($W_{k,t}^{CD}$).

Flexibility contract parameters are equal for all of them and minimum resting time D_k^{min} is 8 periods, maximum disconnection time D_k^{max} is 60 periods and the number of disconnections per day N_k^{max} is 2.

In terms of analysing the activation signals, some loads are not useful because they consume only during down-regulation periods like Loads-CD ID 3, 14, 15, 16 and 21 based on the reference ID appeared in Table 1.

Additionally, during the second downward regulation period, loads 13, 19 and 20 could provide the flexibility service at lower cost than load 22 but their power is not enough.

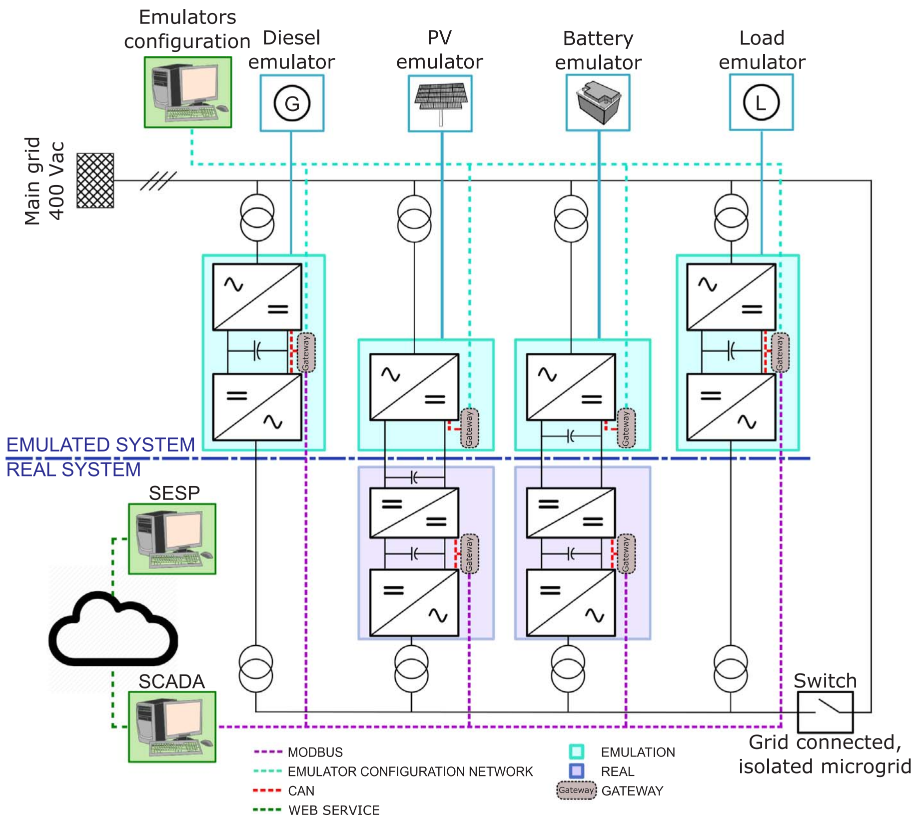
6. Experimental validation

The purpose of the experimental validation in this study is to verify that the laboratory emulators can carry out SESP Platform tests. In order to do that, the laboratory devices and functionalities must be verified to ensure the proper laboratory performance.

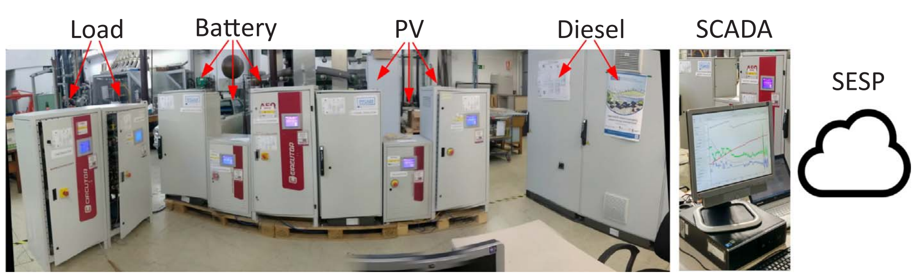
An emulation platform allows to transform software computed variables to real physical magnitudes such as voltages, currents or powers as Prieto-Araujo et al. defined in [60]. This way, real equipment can be connected to the emulator to check its proper behaviour. So, the platform is adequate to test the system presented above while, at the same time, the communication architecture can be validated.

6.1. Test platform description

The test platform scheme is shown in Fig. 12(a). It consists of two subsystems. The first one is composed by the emulated systems such as diesel generators, photovoltaic generators, batteries and loads. These emulators mimic the behaviour of the corresponding real device and their configuration is performed through a central emulators configuration PC, which is interconnected with the emulators through an internal communication network. The second subsystem is composed by real devices like photovoltaic and battery inverters. Moreover, they can be connected or disconnected from the external grid to emulate an isolated or grid connected system. This paper only considers the grid



(a) CITCEA-UPC test platform scheme



(b) Microgrid photo

Fig. 12. CITCEA-UPC test platform.

connected operation and the switch is closed. Additionally, the real subsystem includes the power transformers, SESP cloud, laboratory SCADA and their communication network with the test platform.

In the case study, laboratory emulators behave as EMPOWER field devices and the laboratory SCADA reports metered values to the SESP Platform as local controllers do in the real field. The load emulator output is the aggregated consumption of several loads. These loads can be connected or disconnected according to the predefined contracts and the SESP orders. In the same way, the PV emulator represents several PV systems that can be controlled by the SESP individually. The case study has two batteries and the corresponding emulator applies directly the sum of the SESP battery setpoints. There are no diesel generators. Additionally, control signals are set by the laboratory SESP computer emulating SESP control signals and platform.

6.2. Results

The first test performed is the baseline emulation. Using the emulator configuration computer, the baseline scenario has been introduced into the emulators. This scenario corresponds to the system without SESP commands. Despite not receiving any order in this test, the emulators includes the flexibility contracts for each load, generator and battery and the functionality to act accordingly to the order received. Fig. 13 compares the simulated case study and the emulated one. It can be observed a good accuracy between the results and how the test platform can reproduce the scenario properly. From this result, it can be concluded that the emulators behave properly in the absence of SESP orders.

Once the emulators have been tested, the next step is to check the real platform in charge to execute the optimal market operation and to send the different orders in real time to the different devices. This platform corresponds to the SESP and SCADA systems. The SESP has been implemented in a personal computer which executes the optimization problem and obtains all planned orders for the whole day. Then, these orders are sent to the SCADA system. This system executes a real-time routine to send the orders at the required instant. The orders are sent by Ethernet under modbus protocol to the different devices (loads, PV generators and batteries). Fig. 14 shows a comparison of the simulated and the emulated results, including the real SESP and SCADA systems. In contrast to the results shown in the previous section, which are presented in terms of energy, here it is shown the active power. Nevertheless, as periods represent quarters, the difference relies on a multiplication factor of 4. As it can be observed, the simulated and emulated results agree. The emulated baseline scenario and the

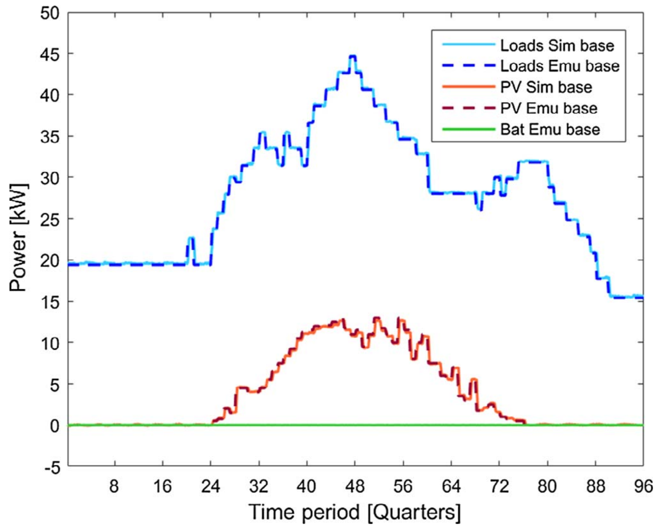


Fig. 13. Comparison between simulated and emulated results: baseline case (SESP is disabled).

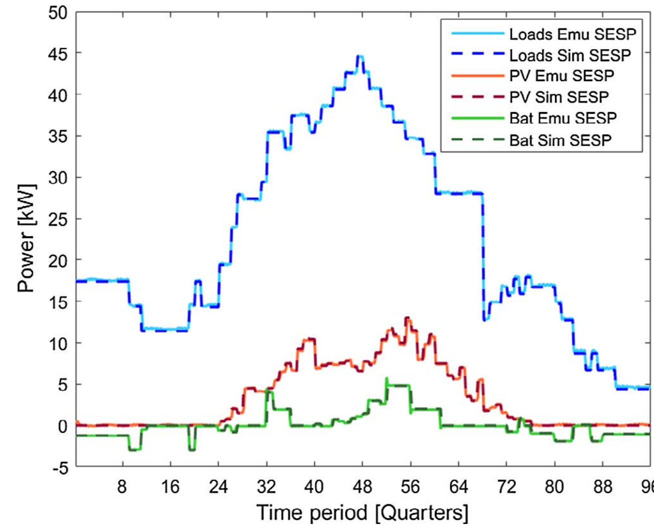


Fig. 14. Comparison between simulated and emulated results with the SESP. Emulated results includes the real SESP platform implemented.

emulated scenario with the SESP platform agrees with the simulated results. So, it can be concluded that the activated flexibility meet the DSO request as shown in the simulated case in the previous section. Hence, it can be concluded that the real implementation of the SESP platform is successful.

7. Conclusions

The integration of DER into the distribution grids can lead to technical issues affecting the power quality. Therefore, new concepts are required to facilitate the transition of the current system to the smart grid system. DSO can use the flexibility provided by new technologies as a tool to improve these power quality issues. In this direction, this paper has addressed the development of a local flexibility market enabling the capacity to meet the DSO requests through a Smart Energy Service Provider (SESP) Platform.

The local flexibility market includes the required software and hardware tools to optimally manage the real devices. The software consists of a formulation of an optimization problem and its implementation in an open source code. The optimization problem is formulated to include multiple DER devices such as disconnectable and shiftable loads, curtailable (reducible and disconnectable) generators as well as batteries. Its purpose is to offer to the DSO operators the possibility to increase or decrease the generation and load of a local area. Then, the hardware and its associated software, are in charge of managing the determined orders in real-time ensuring the application of the optimal operation schedule.

A study case has been simulated showing the proper behaviour of the software. Then, this simulation case study has been implemented in a laboratory platform verifying that the developed local flexibility market and the SESP Platform can be tested in the laboratory.

Acknowledgement

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Appendix A. Index of sets, parameters and variables

Tables A.2,A.3,A.4,A.5,A.6,A.7,A.8

Table A.2
Sets and subsets.

T	Set of periods, indexed by t
T^{+}	Subset of periods with DSO requests for upward regulation
T^{-}	Subset of periods with DSO requests for downward regulation
K	Set of non-buffered flexible loads, indexed by k
K^{CD}	Subset of flexible load units of type curtailable disconnectable
K^{SP}	Subset of flexible load units of type shiftable profile
C	Set of shiftable load periods, indexed by c. It depends on each k
G	Set of flexible distributed generators, indexed by g
G^{r}	Subset of reducible distributed generators
G^{d}	Subset of disconnectable distributed generators
B	Set of storage units, indexed by b

Table A.3
DSO parameter.

D_t^{DSO}	DSO request in the local flexibility market during period t [kW h/period]

Table A.4
Contract price parameters.

$P^{Gr}_{g,t}$	Price in local flexibility market contract for curtailing the reducible generator unit $g \in G^r$ during period t [NOK/kW h]
$P^{Gd}_{g,t}$	Price in local flexibility market contract for curtailing the disconnectable generator unit $g \in G^d$ during period t [NOK/kW h]
$P^{B,in}_{b,t}$	Price to charge the battery unit b during period t [NOK/kW h]
$P^{B,out}_{b,t}$	Price in local flexibility market contract for discharging the battery unit b during period t [NOK/kW h]
P^{CD}_{k}	Price in local flexibility market contract for disconnecting the load unit $k \in K^{CD}$ during period t [NOK]
P^{SP}_{k}	Price in local flexibility market contract for shifting the load unit $k \in K^{SP}$ one period [NOK]

Table A.5
Generation parameters.

$F^{Gr}_{g,t}$	Forecasted generation of reducible generation the unit g during period t [kW h]
$F^{Gd}_{g,t}$	Forecasted generation of disconnectable generation the unit g during period t [kW h]

Table A.6
Battery parameters.

O^{max}_{b}	Maximum storage capacity of the storage unit b [kW h]
Q^{in}_{b}	Maximum charging capacity of the storage unit b [kW h]
Q^{out}_{b}	Maximum discharging capacity of the storage unit b [kW h]
η^{in}_{b}	Efficiency factor for charging the storage unit b [p.u.]
η^{out}_{b}	Efficiency factor for discharging the storage unit b [p.u.]

Table A.7
Flexible load parameters.

$W^{CD}_{k,t}$	Curtailable load consumption forecast for the load unit k during period t [kW h]
$W^{SP}_{k,t}$	Shiftable load consumption forecast for the load unit k during period t [kW h]
N^{max}_{k}	Maximum number of disconnections for the load unit k during the planning horizon T [#]
D^{min}_{k}	Minimum time duration between two curtailments of the load unit k [# of periods]
D^{max}_{k}	Maximum curtailment duration of the load unit k [# of periods]
$V^{start}_{k,c}$	Start-period of forecasted consumption of the load unit k during shift time interval c [#]
$V^{end}_{k,c}$	End-period of forecasted consumption of the load unit k during shift time interval c [#]
$T^{start}_{k,c}$	Earliest possible start period for shifting the load unit k during time interval c [#]
$T^{end}_{k,c}$	Latest possible end period for shifting the load unit k during time interval c [#]

Table A.8
Variables

$\chi_{g,t}^{Gr}$	Total amount of electricity generation curtailed of reducible the generator unit g during period t [kW h]
$\chi_{g,t}^{Gd}$	Total amount of electricity generation curtailed of disconnectable the generator unit g during period t [kW h]
$\delta_{g,t}^{G}$	Binary variable = 1 if curtailment of the disconnectable the generator unit g is applied during period t, else 0
$\sigma_{b,t}^{in}$	Energy charged by the storage unit b during period t [kW h]
$\sigma_{b,t}^{out}$	Energy discharged by the storage unit b during period t [kW h]
$\sigma_{b,t}^{soc}$	State of charge of the storage unit b during period t [kW h]
$\delta_{b,t}^{out}$	Binary variable = 1 if the battery unit b is discharging electricity during period t, else 0
$\delta_{k,t}^{start}$	Binary variable = 1 if curtailment of the disconnectable load unit k starts during period t, else 0
$\delta_{k,t}^{run}$	Binary variable = 1 if curtailment of the disconnectable load unit k is running in time period t, else 0
$\delta_{k,t}^{end}$	Binary variable = 1 if curtailment of the disconnectable load unit k ends during period t, else 0
$\omega_{k,t}$	Delivered energy to the shiftable load unit k during period t [kW h]
$\gamma_{k,t}$	Binary variable = 1 if the shiftable load k begins consuming at period t, else 0
$\rho_{k,c}$	Time period when the shiftable load k for load shift interval c begins consuming [#]

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