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Congestion management market design- Approach for the Nordics and Central Europe

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HIGHLIGHTS

- Holistic understanding of congestion, its alternatives (market and non-market-based) and criteria to evaluate a solution.
- Defining when congestion management market (CMM) can be useful and its role.
- Propose three congestion management services, including long-term, short-term and operational.
- Propose and compare different CMM models.

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ABSTRACT

It is undeniable that congestion is an increasing problem of power systems nowadays. Ways to tackle it embrace non-market and market-based solutions. Network reinforcement, network reconfiguration, reactive power control, etc., are some instances of non-market-based solutions. In contrast, solutions based on market mechanisms such as zonal pricing, nodal pricing, redispatch, and markets for flexibility (e.g., congestion management market (CMM)) are considered market-based alternatives. Among the said alternatives, CMM is the newest concept, leading to many unknown issues associated with it that initiated us to present the article. The article discusses the congestion problem and criteria to evaluate congestion management (CM) alternatives. In addition, to have a practical grasp of CM, its cost, and how congestion is traditionally handled, a real-life problem solving of a distribution system operator (DSO) is presented. Concerning CMMs, four conditions that need to be met before considering CMM as a CM solution are specified. In addition, three CM services, including long-term, short-term, and operational, followed by different implementations of those services, are proposed and compared. In general, CMM design is a complex problem because several stakeholders with different tasks, visions, business models, and capabilities must work together; therefore, looking at the situation from various angles is beneficial. This article thrives on providing a vivid view on the features of different CMM models to stakeholders such as DSOs, transmission system operators (TSOs), flexibility service providers (FSPs), regulators, existing markets, retailers, balance responsible parties (BRPs), etc., that may have interest in CMMs.

1. Introduction

Nowadays, due to changes in both generation and consumption, distribution networks experience increasing stress that can cause congestion. In the consumption sector, about 2.5 billion people are expected to be added to urban areas worldwide within the next 30 years

Abbreviations: BAL, Balancing; BRP, Balance responsible party; CM, Congestion management; CMM, Congestion management market; CRP, Conditional re-profiling product; CVC, Coordinated voltage control; DA, Day-ahead; DSO, Distribution system operator; EV, Electric vehicle; FR, Flexibility register; FSP, Flexibility service provider; GCT, Gate closure time; GOT, Gate opening time; GW, Gigawatt; HC, Hosting capacity; I, Current; ID, Intra day; IT, Information technology; kW, Kilowatt; LFM, Local flexibility market; LMP, Locational marginal pricing; LV, Low voltage; M, Maintenance; MOL, Merit order list; MS, Market splitting; MV, Medium voltage; MW, Megawatt; OLTC, On-load tap changer; PV, Photovoltaic; P2P, Peer-to-peer; R, Resistance; RES, Renewable energy sources; SRP, Scheduled re-profiling product; TLC, Traffic light concept; TSO, Transmission system operator; VR, Voltage regulator; V2G, Vehicle to grid.

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[1]. Besides, the international energy agency (IEA) electric vehicles' (EVs') outlook anticipates an increasing growth over the next decade. According to the stated policy scenario incorporating the existing governmental policies, EVs will reach 145 million in 2030 compared to 7.2 million in 2019 [2]. This level of electrification will lead to 550TWh electricity demand in 2030 (about a six-fold rise from the 2019 level). In Europe, EV demand will account for 4 percent of electricity consumption (i.e., national/regional) in 2030 [2]. Urbanization and upward trend in EV penetration are two instances of higher stress on distribution networks in the consumer segment for years to come.

In the production sector, decentralization of electricity generation and moving toward sustainable electricity production have pushed notably solar generation into cities. The median size of a residential solar unit was 6.4 kW in 2018, and the average capacity of solar plants varies between 4.64 and 13.75 MW in Europe [3]. The global installed capacity of solar PV has skyrocketed from 40 GW in 2010 to 580 GW in 2019 [4]. Although the rise in installed capacity of solar PVs is primarily due to the installation of utility-scale power plants connected to transmission systems, the penetration of small and average size PV installations connected to distribution networks is inevitable. In the final analysis, likely, most residential (6.4 kW) and average-sized solar plants (4.64–13.75 MW) are connected to distribution systems leading to potential stress on the grids.

In addition to the mentioned factors in the production and consumption sectors, new business models have recently been introduced that do not consider the boundaries of distribution network operation. Nowadays, consumers, often enabled by aggregators, are encouraged to play an active role as prosumers and deliver their services to a market of their choice. Although this business model benefits the service providers, it can add further challenges to the distribution grid operation under some circumstances. For instance, a rise in balancing power market price can unify the behaviors of many prosumers. The unification of consumers' behavior can cause congestion in the distribution network. In addition, DSOs can no longer safely rely on predicted grid profiles because a consumer can turn to a producer or vice versa, instantly reacting to an external factor (i.e., market signals). The unpredictable behavior of loads and generations leads to higher uncertainty and volatility in network state forecast, which is not favorable from a congestion management perspective because a DSO cannot safely forecast the network's congestion state and prepare for it.

As discussed in this chapter, with a drastic change in consumption, the emergence of renewable generation and new business models, the distribution network's operation could be highly unpredictable and challenging, causing problems like congestion. Flexibility utilization as a solution provides grid operators a chance to properly manage to release stress from the distribution system and avoid congestion. For instance, EV charging that could significantly increase consumption in the evening can be distributed during working hours using flexibility when PV generation is high. High PV production and a high number of EVs alone can be problematic in a distribution network, while flexibility allows in having them together as a win–win solution.

According to the international renewable energy agency's (IRENA) report on the world energy transition outlook [5], flexibility is a crucial enabler of integration of renewable energy sources (RES) or the backbone of the electricity systems of the future. Flexibility utilization can happen when four factors, including enabling technologies, business models, innovation in system operators, and a proper flexibility market, coexist. Battery storage, demand-side management, and blockchain [6,7] are some enabling technologies that open doors to new applications that unlock the system's flexibility. Innovative business models are essential to monetizing the value created by these technologies. For example, a business model should convince the end customers that flexibility provision does not compromise the customers' comfort (i.e., indoor temperature); otherwise, the FSP might lack flexible resources no matter the readiness level of enabling technologies. On the gird operator side, proper utilization of flexibility that involves network monitoring, decision making, and control is required. Finally, the flexibility market as the final piece of the puzzle should be designed to bridge FSPs to grid operators while considering the needs and capabilities of stakeholders.

1.1. Literature review

Many pieces of literature have devoted their research to different aspects of the local flexibility market (LFM), such as transparency, liquidity, coordination, product design, etc. Besides, to have a more holistic understanding, some features of pioneering flexibility markets in Europe such as Enera [8], NODES [9], GOPACS [10], Piclo flex [11], and ongoing research projects including INTERRFACE and CoordiNet are added to the discussions.

1.1.1. Transparency

The importance of market rules transparency and settlement systems, reducing market entry barriers, and market power are some challenges ahead of starting LFM [12]. It was recommended that LFM begin with an auction where grid operators determine flexibility quantities and price is set by the market process in a regulated platform. Once the liquidity is ensured, a transition to a competitive market can be realized. From a functional perspective, we propose starting operating LFM by limiting its functionality to CM. Once CMM has gained momentum, more functionality can be added to the LFM. For example, not only system operators but also BRPs are allowed to buy flexibility. Since making any change in the market might have significant consequences, it is recommended that impact analysis is done first before applying a new change in the market. Allowing BRPs to buy flexibility would mean that competition to buy flexibility is higher for grid operators, leading to more expensive bids in the market. On the other hand, a market with more buyers and more transactions is more reliable than a market with low liquidity when BRPs do not participate as buyers. A similar approach has been taken by pioneering flexibility markets in Europe, including Enera and NODES. They both allow DSOs and TSOs to access the market; however, CM for DSOs came into full operation first.

Transparency is an essential aspect of the market that includes baseline methodology, among others (e.g., market rules), in the settlement stage. Baseline methodology could be realized using a historical data approach, statistical sampling, maximum baseload, meter before meter after, and metering generator [13]. Those methods have been evaluated and compared according to their accuracy, simplicity, integrity, and efficacy in the CoordiNet project. The fitness of each baseline methodology is dependent on the factors including CMM design, flexibility products, and market participants. Therefore, baseline methodology's merit is case-dependent; for instance, a baseline that works best in a country might not necessarily remain the best option in another country.

In addition to the mentioned baseline methods, machine-learning-based methods alone or combined with traditional methods (e.g., historical data of smart meters) could be utilized in the baseline methodology [14]. Although using machine learning techniques can result in high-quality forecasts [14], it should be stressed that keeping a balance between simplicity and accuracy of baseline calculations should be considered. If the settlement calculations become complex, liquidity is compromised because all stakeholders might not be willing to enter a local market with a complex settlement process. In addition, it becomes more difficult for stakeholders to learn the market, adding risk to market participation and probably higher flexibility prices. In fact, settlement is one of the critical stages in the market where a proper understanding between stakeholders is required; otherwise, market liquidity may be compromised.

Local flexibility market operator (LFMO) plays a vital role in market transparency. LFMO is responsible for providing, administrating, clearing, and settling the platform [15]. As LFMO should ensure a level playing field for all market participants, it can be a third party[1] that maintains complete independence from trading activities [16]. ENTSO-E recommends that grid operators be neutral market facilitators besides LFMOs [16].

1.1.2. Coordination

TSO-DSO coordination as a challenge can arise ahead of LFM operation [17]. Coordination is the area where it attracts a lot of debate [12,18–22]. Coordination of system operators is dependent on several factors such as flexibility service type, grid's current state, the share of RESs, market design, and regulatory framework [19,21,22]. Therefore, coordination should be allowed to evolve at any moment if circumstances (e.g., due to market structure development [23]) or policy changes. Three different TSO-DSO coordination schemes are proposed in [21]. Their game-theoretical analysis found that co-optimization of TSO-DSO resources is the most efficient solution following the decentralized coordination scheme where grid operators clear their markets separately (non-cooperative game) by estimating the resultant's flow on the other grid operator. Theoretically, TSO-DSO co-optimization may be the most efficient solution; however, it does not seem feasible from a practical perspective because integrating DSOs and TSO's information technology (IT) systems requires a comprehensive harmonization for network models, data, protocols, etc. On the other hand, although the least efficient coordination scheme prioritizes DSOs to TSO in resource allocation [21], it seems more viable from a practical viewpoint. In this scheme, the situation can fall into two categories depending on the direction (upward/downward) of flexibility need at a particular congestion area.

Suppose both DSO and TSO have flexibility needs in the same direction (whether upward or downward); coordination is much easier than when their needs are in the opposite direction. In the latter case, the coordination can be such that TSO may choose a flexibility resource in another location with no local flexibility need, as long as it has a similar positive effect on the congestion. The price difference then should be agreed to be shared between the DSO and the TSO. GOPACS is indeed a real-life example of the TSO-DSO coordination platform. It assures that no conflicting flexibility activation happens. GOPACS can be understood as an intermediary between grid operators and the market. In fact, flexibility trade does not occur on GOPACS, and it procures flexibility from intraday market energy trading platform Amsterdam (ETPA) operational in the Netherlands [16].

In addition to the coordination need between grid operators, coordination between LFM and existing markets (e.g., DA, balancing) should be considered in LFM design [24]. Market timing is an influential factor in LFM integration into the existing markets. For instance, NODES, GOPACS, and Enera are synchronized with intraday markets of Nord-Pool, ETPA, and EPEX SPOT, respectively [25]. The idea is that existing flexibility available in the intraday market flows to the LFM. In this case, to secure liquidity, by offering some incentives (e.g., free of charge market participation, user-friendly bidding interface, etc.), LFM should encourage FSPs to redirect their flexibilities from the intraday market[2] to LFM. Another way of increasing the flexibility volume in LFM is to make the market reliable for the FSPs to motivate them for flexibility infrastructure investment. By proposing a long lead time like six months (up to 7 years) in Piclo Flex [26], investment becomes more economically viable for FSPs because reservation payment guarantees a revenue channel for FSPs. As discussed, market timing can significantly influence the liquidity of the LFM; therefore, it is investigated in proposed market designs in this article.

1.1.3. Flexibility product

In product design, flexibility product attributes should be adjusted to meet the needs and capabilities of stakeholders. ASM report [27] states several attributes for flexibility products. Table 1 introduces some of them. The report highlights that the mentioned attributes set a minimum common ground with cross-border balancing and wholesale market. It is recommended that such standardization is implemented at least at the member state level to limit the costs for market participants in offering the products. However, as congestion management is addressed through different mechanisms in different Member States, a European harmonization of the products for congestion management is not required.

Most flexibility markets like Piclo Flex and Enera utilize a standardized flexibility product. GOPACS also uses standardized intraday products from ETPA [16]. Standardized products allow transparent competition between FSPs as a merit order list (MOL) of bids can be created, and the buyer could select the most cost-effective bid from MOL. Market participants should agree on flexibility attributes in a market with standardized products. For example, if the gap among the grid operators' needs is not wide, having standardized products seems better, especially if DSOs are the only flexibility buyers like in PicloFlex. When TSOs and DSOs are involved in procuring flexibility, finding a standardized product as a "one size fits all" approach in terms of aggregation resolution, bid size and lead time, etc., can be challenging.

In contrast, as a market with unstandardized products, NODES allows FSPs to participate in the market with flexibility attributes of their choice. DSOs can browse through bids and filter them according to their needs. Market participation might be more flexible for participants leading to a lower market barrier; however, portfolio optimization of FSPs and DSOs' decision-making can be more complex because the optimization should deal with optimality in a larger solution space and fewer constraints. In general, standardized and unstandardized flexibility products have particular features, and there is no universal solution to flexibility product design.

1.2. Objectives

The objectives of the article are as follows:

- Find out the requirements for CMM utilization.
- Clarify the market's role in CM and criteria to evaluate if CMM is useful.
- Propose different CMM setups to complement non-market-based solutions.
- Consider CMM aspects, such as coordination, liquidity, product design, while comparing various market models.
- Find out how CMM could work in practice.

Table 1
Flexibility product attributes.

Attributes	Definition
Minimum bid size	The minimum bid size (kW) that is allowed in the market.
Maximum bid size	The maximum bid size (kW) that is allowed in the market.
Location	The place where flexibility is required.
Activation time	The time when flexibility must be activated.
Duration	The full activation time of flexibility.
Recovery time	Minimum time between activations.
Volume	The amount of flexibility per kW.
Direction	The direction of flexibility whether up or down-regulation.

[1] All pioneering flexibility markets in Europe are operated by third parties. For example, Enera is owned by EPEX SPOT that is one of the largest power exchanges in Europe [16].

[2] Adding locational information to intraday market bids allows integration of LFM and intraday market. The Nordic-Baltic demonstration under horizon 2020 INTERRFACE project, has implemented the approach.

1.3. Motivations and innovative contributions

A DSO as a party jointing and serving several stakeholders (e.g., aggregators, customers, producers, retailers, etc.) requires keeping up with stakeholders' transition toward digitalization, decarbonization, and decentralization [28]. For instance, by adding CMM to its CM tools, a DSO may overcome the consequences of changes for its grid. Otherwise, a DSO with only a few traditional options like network reinforcement will fall behind the other stakeholders because the pace of transition is unprecedented. Although mismanagement of the situation could cause instability to a distribution network operation, proper management can turn the threat into an opportunity. For instance, according to the sustainable development scenario[3] by 2030 [2], promoting EV charging to off-peak work-based charging in day time can shift 50 GW of the network's congestion periods to work hours, adding a possibility to utilize electricity generation from PVs. As another example, as a response to price signals (e.g., using a CMM), 70 GW of peak demand can be distributed to off-peak hours [2]. A flexibility market with a proper design that provides transparency, neutrality, reliability, and liquidity to its market participants can systematically shift EV charging to off-peak hours. Therefore, having an active solution based on the market mechanism for congestion management is a real need of today and future distribution systems. The motivations of the authors presenting the current article are as follows:

- Holistic understanding and analysis of various CMM designs, including coordination, liquidity, and product design, are missing in scientific articles.
- In CMM design and implementation, the whole market process, including IT systems, grid, product and market prequalification, trade on the market platform, activation, and settlement, needs to be considered, not only a section.
- The analysis must be done in a real-life context as well, not only in a theoretical one.
- Involved stakeholders' viewpoints should be considered in the market design stage to ensure desired market properties like liquidity.

The mentioned motivations led to prepare the current article with the following contributions:

- Since CM requires a profound understanding of the problem and its available solutions, the article commences with discussing the congestion problem, ways to tackle it, and criteria to evaluate the CM solutions. In addition, a real-world congestion management case is presented to highlight one instance of the traditional CM and its cost. The novelty is a real-world approach of the article toward CM.
- The requirement for using CMM and its role is presented without assuming that CMM utilization is always useful.
- Different services for CMM, including long-term, short-term and operational, are proposed. In addition, CRP and SRP as CM products are presented in the article. Combining CM services and flexibility products in the current form has not been introduced previously.
- Three market options derived from the active system management (ASM) report [27] are structured, developed, and presented in the article as a result of three years of discussion and interactions with several project partners (DSOs, TSOs, aggregators, regulators, BRPs, software companies, universities, etc.) under INTERRFACE project [29].

[3] The Sustainable Development Scenario incorporates the targets of the EV30@30 Campaign to collectively reach a 30% market share for electric vehicles in all modes except two-wheelers by 2030. The EV30@30 Campaign was launched at the Eighth Clean Energy Ministerial in 2017. The participating countries are Canada, China, Finland, France, India, Japan, Mexico, Netherlands, Norway, Sweden and United Kingdom.

1.4. Scope

By considering the increasing trend in intermittent renewable integration to the power system, the authors believe that congestion management is the urgent need of system operators; otherwise, the network state frequently turns red (according to the traffic light concept (TLC) [30]). TLC introduces three colors representing a network's state at a particular period of time and a specific network segment. Green phase signals that a potential or actual congestion does not exist; therefore, the stakeholders could freely utilize their flexibility in any market. Yellow network state warns stakeholders that actual or potential network congestion exists and grid operator announces its flexibility needs in LFM. Flexibility providers are expected to participate in the market to eliminate congestion. The red phase represents an immediate risk to the stability of the network, where the grid operator can take control of any resource to secure the network operation.

Since the red state should largely be avoided for the network's stability, network operators and all market players are interested in congestion management such as aggregators, BRPs, and retailers, because the red network state would prioritize the grid's stability over the market operation. In fact, the red phase disturbs the stakeholders' businesses because stakeholders use network services in their value chain. Therefore, the current article focuses on the yellow network state when the congestion management market (CMM) design is essential to meet the congestion management needs of DSOs and TSOs. Once CMM is up and running, it can evolve to the LFM by adding functionalities in line with stakeholders' needs.

The article is organized as follows.

Section 2 defines the congestion problem and discusses CM alternatives and criteria for evaluating available options. Moreover, a real-life congestion management example in Finland is discussed to highlight the traditional DSO's CM and its costs. Section 3 contains a discussion on the conditions when CMM can be used and the roles of CMM for grid operators. Section 4 explains the different CMM services, including short-term, operational, and long-term. Section 5 offers various models that CMM can be designed and implemented, followed by a comparison concerning features of different CMM designs. Finally, the conclusion is drawn in Section 6.

2. Congestion problem

2.1. Definition

The mentioned changes in Section 1 (e.g., PV production, consumption rise, etc.), technically speaking, can cause overloading and voltage violations known as a congested state on the distribution Networks. Regarding overloading, it is defined by the thermal limits of components. Factors such as the device's resistance (R), flowing current (I), heat dissipation rate (influenced by wind speed, ambient temperature, solar irradiance, soil temperature, humidity, etc.) impact the climate of the elements associated with overloading [31]. Regarding the voltage quality, keeping the voltage magnitude inside the permissible limits (e.g., +-10% of nominal voltage for 95% of the week [32] in distribution systems) is the priority for congestion management.

2.2. Alternatives

2.2.1. Non-market-based

Ways to tackle congestion fall into the market and non-market-based solutions. In the latter case, TSOs and DSOs have similar alternatives (regardless of implementation-level differences) for CM. Network reinforcement, active power curtailment [33], network reconfiguration [34], grid code, grid tariff [35–37], reactive power compensation

[38,39], contracted demand response, and coordinated voltage control (CVC) [40,41] are instances of non-market-based solutions for CM [42]. Non-market-based solutions like network reinforcement are traditional CM solutions to grid operators. As a result, grid operators have more tendency toward traditional solutions than novel solutions (i.e., market-based) because of having the technical know-how. Besides, self-governance is the key feature of some non-market-based solutions (e.g., network reconfiguration) that reduces the required amount of coordination with other stakeholders. Moreover, it is worth mentioning that national regulations could influence the tendency of grid operators to one solution than the other. For instance, in Germany, network topology changes should be done before using any market-based approach.

2.2.2. Market-based

An example of an electricity market is Nord Pool [43], which operates day ahead (DA) and intraday (ID) markets in 14 European countries. Together with the European network of transmission system operators for electricity (ENTSO-E) and regional security coordinators (RSCs), Nord Pool already applies CM measures for DA and ID markets. Three approaches can be taken into account for DA market clearance. The first is based on a nodal pricing model (also called locational marginal pricing (LMP)) [44]. In LMP, the best answer to a cost minimization problem should be found by calculating security-constrained optimal power flow (SCOPF) [44], subject to generation restrictions, transmission constraints, and energy balance limitations. Apart from the advantages of the LMP method, such as complete involvement of network limits in the market clearing process, due to a massive number of prices, price formation is cumbersome and time-consuming [17], not desirable for market operators and participants. Besides, it seems challenging to implement the nodal pricing system where customers, according to their location in the power system, experience different electricity prices that may lead to customer dissatisfaction and a sense of inequality. Therefore, spot markets in Europe (e.g., Nord Pool) utilize a simplified version of the LMP known as "zonal pricing"[4] with predetermined bidding zones[5]. There is a debate over the pros and cons of each method (LMP versus MS) [45,46]. The extreme form of the zonal pricing model is the uniform pricing system, where all the nodes share an identical energy price [45]. It is highly likely to hit transmission restrictions using only the uniform model, so ex-post adjustment of market outcomes known as counter-trading is necessary for the uniform model. Regardless of the differences of the three mentioned market-clearing processes, they all thrive not to cause any congestion in transmission level by considering necessary mechanisms in their market process. It should be stressed that although CM has been considered in spot market design in Europe, it still does not eradicate the need for congestion in the TSO level because congestion could occur inside the bidding zones.

In distribution systems, the DSO's approach to tackle the increasing need for CM by using market-based solutions is not mature yet, which is why development in several pioneering projects is still ongoing. Coordination platform GOPACS and ETPA market are the only commercially active and running platforms with technology readiness level (TRL) 9 among flexibility markets [47].

2.3. Evaluation of alternatives

The authors believe that a selected solution for CM should offer the highest aggregated amount of quality attributes such as cost-effectivity, reliability, durability, feasibility, and environmental protection, among others. It should be noted that a solution that satisfies the mentioned factors best may not necessarily remain the best solution in another congestion problem as CM is case-dependent. For instance, a few hours of over-voltage congestion per year do not justify network reinforcement as a solution compared to production curtailment. Reinforcement does not seem cost-effective in that case; however, it is often a reliable, durable, and feasible solution. In contrast, a hundred hours of active power curtailment annually is not a wise CM decision for a wind farm because of opportunity loss and environmental considerations, especially if the alternative energy sources are not renewable. As evident, like any other management problem, CM requires a profound understanding of the problem and its available solutions so that making it possible to match the problem with the best solution. Therefore, adding a new set of alternatives such as approaches based on market mechanisms to the existing solutions, in a general view, could expand network operators' possibilities.

2.4. A real-world congestion management example

In this subsection, a real-world CM case will be discussed to show the attitude of a typical DSO dealing with congestion considering the order of magnitude of investment costs. The distribution network shown in Fig. 1 belongs to a Finnish DSO.

2.4.1. Before reinforcement

Fig. 1 visualizes the distribution network before and after reinforcement. Two distribution networks, A and B, are separately supplied by primary substations A and B (dotted-line boxes), while network C and two backup feeders J03 and J04 are built later (shown in Bold). MV and LV stand for medium and low voltage, respectively. Backup connections J01 and J02 connect MV feeders of two substations when necessary (e.g., contingency). The backup feeders' primary use is when primary substation A faces an outage (i.e., transformer failure, etc.). Fig. 2 depicts the loading of substation A in normal situations from January 2016 to October 2019. The graph's general trend induces that loading during months December and January is close to the maximum substation's capacity (i.e., due to the high temperature-dependency of loads) while the loading declines to about 30 percent of the substation's capacity in the summertime (see Fig. 3).

Table 2 provides information about maximum loading and extra capacity of substations during the maximum loading conditions. Since 62.5 percent of substation B's capacity is unused (even in peak loading conditions), the capacity is utilized by feeding substation A through feeders J01, J02 when an incident occurs in substation A. The downside of the contingency plan is that the loading of feeders J01 and J02 could hit 117 and 133 percent of backup feeders' ampacity, respectively. Therefore, the DSO has decided to build a new substation and two backup feeders to avoid overloading of J01 and J02 during substation A contingencies.

2.4.2. After reinforcement

By building substation C in 2019, the network was reinforced, as shown in Fig. 1. Substation C has been oversized so that almost 80 percent of its capacity is always free to be utilized by sending energy from substation C to A through backup feeders J03 and J04 when needed. In other words, to avoid overloading J01 and J02, two new feeders, J03 and J04, have been added to support substation A during substation contingencies. According to the design, the whole loading of substation A will be distributed between four backup feeders without causing any congestion.

The congestion was eliminated by investing 1.4 M€ for primary substation C and 0.45 M€ for 12 km backup connections J03 and J04. Although substation C was not built merely for congestion removal of J01 and J02 because it also feeds local loads in area C, it is five times oversized to support substation A when needed. The local loads in network C only occupy 20 percent of 25 MW substation C's capacity.

Since the reinforcement is not done only for congestion management, the portion of the reinforcement costs due to congestion management is worth mentioning. For example, suppose that substation C

[4] also known as market splitting (MS)

[5] Static and dynamic bidding zone formations and reshaping the current bidding zones are discussed in the MS market model [56].

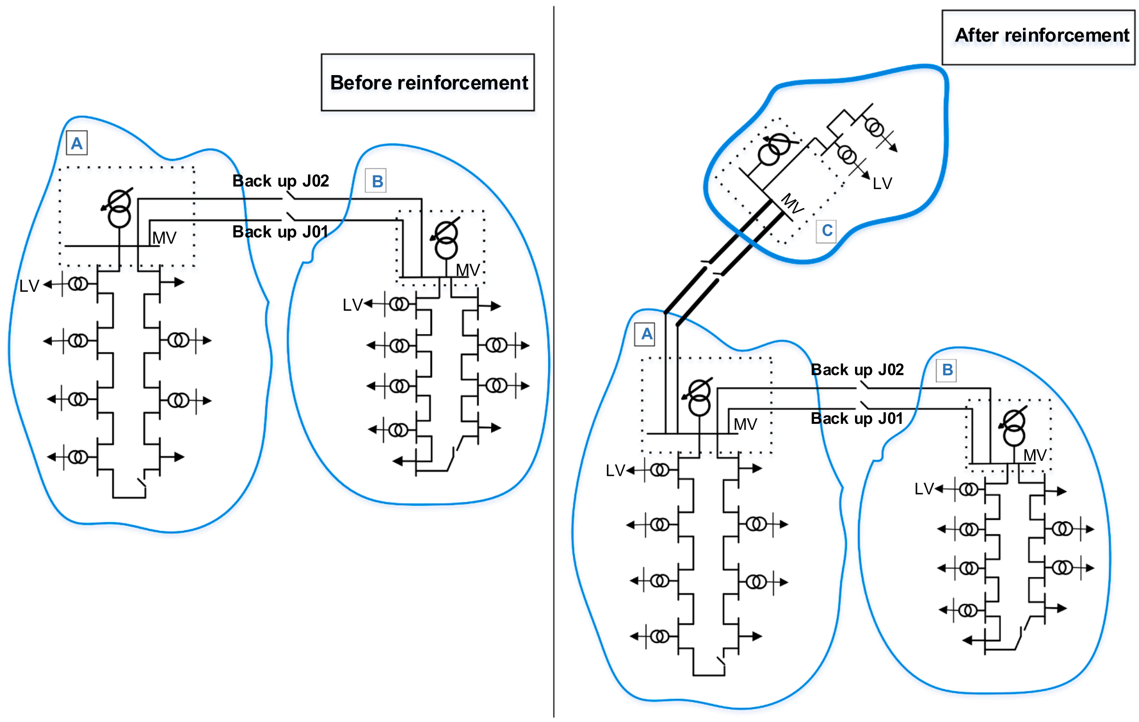

Fig. 1. Network topology before and after reinforcement.

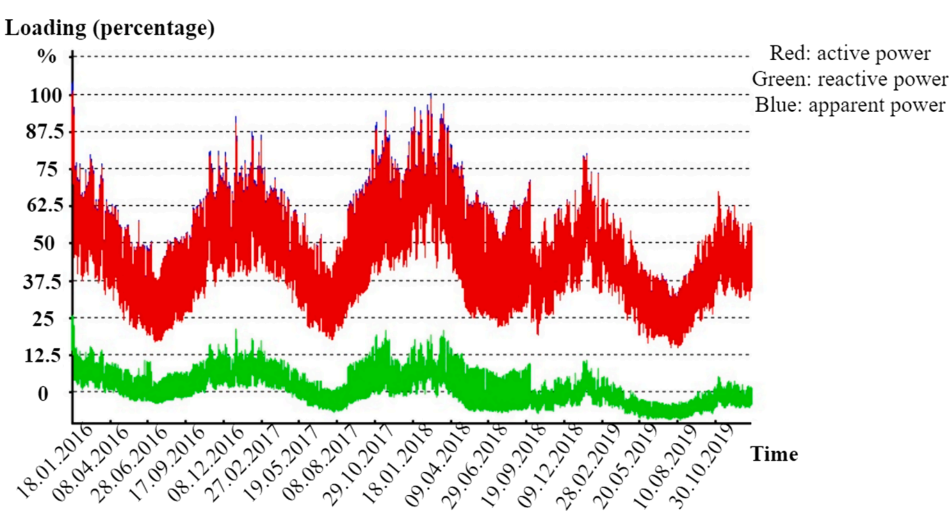

Fig. 2. Loading of substation A.

Table 2
Loading and free capacity of substations.

Substation	Used substation's capacity during maximum loading conditions %	Extra substation's capacity in maximum loading condition %
A	96.8	3.2
B	37.5	62.5

was built only for feeding local loads in area C; its capacity would be 5 MW. In addition, backup feeders J03 and J04 would not be required. According to the DSO's network information system (NIS), the closest rating for the primary substation's transformer (110 kV-20 kV) is 6 MW with a price tag[6] of 240 k€. Table 3 shows that about 548 k€ had been saved[7] if substation C's construction did not consider substation A's CM. It should be stressed that the price difference is an estimation because it has been calculated according to the most expensive substation component (transformer). However, in practice oversizing a substation causes extra costs related to a need for possible more extensive land acquisition, higher ratings of protection systems, cables, etc.

The congestion management alternative of the discussed example scores well in the solution's reliability, durability, and feasibility. Still, in terms of cost-effectiveness and environmental friendliness, it can be criticized. The solution's cost-effectiveness depends on the problem

[6] The prices are valid between 2016 and 2023.

[7] The price of flexibility should be negligible for one year (a few thousand Euros) because of low regularity of congestion occurance.

Table 3
Investment cost comparison.

	Reinforcement cost (k€) including CM	Reinforcement cost (k€) excluding CM
25 MW transformer	338	NA
Back up feeders	450	NA
6 MW transformer	NA	240
Back up feeders	NA	0
Total	788	240

itself, such as the regularity and severity of the congestion problem. [48] reports that a distribution transformer's failure[8] rate with boosted maintenance actions is 0.00345 per unit per year in Finland. Similarly, data collected from 110 kV transformers failures in Germany, Swiss, Netherland, and Austria between 2000 and 2010 report 0.0031 failures (i.e., major[9] and minor[10]) per unit per year [49]. Assuming 30 years of a transformer's lifetime, the failure rate will be 10.35 % per unit per 30 years in Finland. Concerning severity, 17 and 33 percent of overload in feeders J01 and J02 could be managed by a flexibility procurement because the overloading level is not considerable. Therefore, the congestion problem's low regularity and medium severity suggest that a solution based on flexibility (e.g., contracted flexibility) could be used instead of oversizing substation C and building backup feeder J03 and J04. In other words, feeders J01 and J02 could be assisted by up-regulation flexibilities in network area A. Also, utilizing the maximum capacity of the existing networks using flexibility provision could favor environmental aspects compared to network reinforcement.

The said example clarified the current paradigm of CM at the distribution level. With a change in DSO's attitude toward flexibility-based solutions, the authors believe that a portion of the 548 k€ investment could be spent on a flexible provision solution. Nevertheless, flexibility-based solutions shall satisfy an adequate reliability, durability, and feasibility level so that DSOs can trust them as a real solution.

It should be stressed that flexibility procurement should not be seen as a substitute to the network reinforcement but as a complementary solution. In the above example, flexibility procurement could be used for network reinforcement deferral (e.g., five years). The DSO, with reinforcement postponement, can make full use of existing network components' lifetime and buy some time for planning, financing, permission, land acquisition, and implementation. In addition, the initial reinforcement plan might be changed when implementation is delayed, making an updated reinforcement plan more accurate and cost-effective than the initial one. Therefore, the time horizon of solutions based on flexibility (e.g., five years) should not be compared to the reinforcement lifetime (e.g., 30 years) because they are complementary CM solutions.

3. CMM

3.1. When CMM can be utilized

There are some requirements that CMM work as a solution for CM. In other words, since CMM needs the participation of several independent parties, some preconditions should be met to reach a consensus of using CMM as a CM solution.

Firstly, long-term and frequent needs for CM from flexibility buyers (i.e., grid operators) are required. Taking 50 Hz transmission company in Germany as an example: in July 2021, the TSO curtailed 13.387 GWh of renewable energy [50], which is equivalent to charging about 250,000 EVs (e.g., 50kWh battery). In light of a strong need for CMM in Germany, Enera was funded by the German federal ministry of economics and energy to develop a platform for flexibility trade to avoid congestion.

Secondly, flexibility buyers should have an advanced prediction, real-time monitoring, and decision-making systems to make the most of CMMs. For instance, a DSO with a poor distribution automation system (e.g., lack of online measurements) can hardly know what goes wrong in the network, leading to ineffective or random decision-making.

Thirdly, a certain level of technical readiness in the flexibility provider's side is required for flexibility activation and monitoring in a fully functioning CMM. In fact, FSPs aiming to participate in CMM should technically be able to realize the flexibility trade by activating resource/resources (e.g., heat pump, battery, EV charging station, etc.) at a particular time and location. FSPs' capability should be truly tested through the product prequalification process, where grid operators examine whether the FSP can deliver the flexibility in practice by sending the activation request and monitoring the flexibility response [27]. The capability also embraces the performance of the communication system responsible for successfully carrying activation signals to the physical resources. Fourthly, required business models and regulations should support a flexibility trade. For example, the NODES market is not yet implemented on a full scale, and one reason is the regulatory challenges in the way of full-scale development, according to Entsoe [47].

Enera, NODES, Piclo Flex, GOPACS-ETPA reveal that at least those four conditions should be met before choosing CMM as a congestion solution. Germany, Norway, Sweden, the UK, Netherland are European states utilizing flexibility for different grid needs. In Finland, a CMM for DSO does not yet exist due to a little need for congestion management at the moment (i.e., due to a relatively low renewable penetration, strong grids). Likewise, grid automation is not advanced enough to support CMM operation in some European states; thus, using CMM makes little sense.

3.2. Market's role

Among several definitions for flexibility, it can be perceived as the possibility of modifying generation or consumption patterns in reaction to an external signal (a price or activation signal) to contribute to the power system stability cost-effectively [17]. Besides, the market is where several parties can gather to facilitate the exchange of goods or services [24]. By fusing the definitions, the local flexibility market (LFM[11]) becomes the electricity flexibility trading platform to trade flexibility in geographically limited areas such as neighborhoods, communities, towns, and small cities [51].

TSO's balancing, congestion management in both TSO and DSO levels, and balance responsible party (BRP) portfolio optimization are instances of LFM use cases [17]. In addition, portfolio optimization of FSPs and retailers, peer-to-peer (P2P) trading between prosumers [52], and trading between energy communities and microgrids should be included in LFM's use cases. From a grid operator's perspective, intention for participation in the flexibility market can vary. For example, due to excess renewable production, a grid operator in Germany may mainly utilize flexibility to support network adequacy and avoid generation curtailment, whereas, to use the entire lifetime of network assets, a grid operator in Norway may utilize flexibility for reinforcement deferral. In addition, from a broad perspective, LFM availability impacts investment made in relevant services and technologies, such as expanding or introducing flexibility contracts with customers, improving automation

[8] Any unscheduled situation which requires the equipment to be removed from service for investigation, remedial work or replacement is a failure. [49]

[9] Any situation which requires the equipment to be removed from service for a period longer than 7 days for investigation, remedial work or replacement is a major failure. [49]

[10] A minor failure requires remedial work that lasts shorter than 7 days. [49]

[11] CMM is a subset of LFM. In literature, LFM is often used because it embraces more functionalities than CMM.

systems, building new flexibility systems (e.g., stationary battery), etc. Therefore, LFM could play different roles for different stakeholders depending on their needs and interests.

4. Congestion management (CM) services

Flexibility can be utilized to offer different services, including trade (e.g., day-ahead market), non-frequency ancillary (e.g., congestion management), and frequency ancillary services [27]. A non-frequency ancillary service that is the cope of the article is enabled using a particular market process on a market platform where flexibility products are traded. The following paragraph defines the market process, flexibility product, and market platform.

A market process is a merit order list (MOL) that combines specific products in a particular timeframe [27]. The number of MOLs defines the number of markets. To reduce market fragmentation and avoid myriad of markets, the introduced number of CMMs is preferred to be as few as possible [27]. Flexibility on its own can be considered an unstandardized concept [24]; therefore, it is shaped as different flexibility products so that it can be traded as a good for a specific need of a buyer. Different market platforms might be available for flexibility trade from a commercial perspective. A Market platform can be considered a digital platform deploying hardware and associate information technology (IT) systems to help actors interact with each other and perform their tasks.

An integrated approach to active system management (ASM), known as the ASM report [27], introduces a guideline with a focus on TSO-DSO CM and balancing (BAL). The ASM report covers noteworthy discussions concerning TSO-DSO coordination, information exchange, product design, grid and product prequalification, settlement, and CM marketplace. In the article, CMM models in the ASM report have been used to set the basis for discussion in this chapter.

In general, CM services can be realized using different market models, including separate TSO & DSO CM, combined TSO & DSO CM, and combined CM and BAL. According to Fig. 3, option 3 entails one market process for CM and BAL if BAL bids contain locational information used in CMM. BAL bids are useful in CMM only if they have locational information. If locational information doesn't exist in the BAL market or is not granular enough for CM, market options 1 and 2 could be used. Regarding the granularity of BAL bids, low-resolution locational information (e.g., TSO level information) are not useful in CMM, especially for DSOs because DSO level problems usually are either in MV or LV network and therefore, a flexibility resource is required to have locational information with high-resolution if the aim is to utilize BAL bids in CMM.

DSO and TSO CM are two separate processes in option 1, while in option 2, both TSO and DSO CM happen at the same market process. Analyzing the features of options 1 and 2, where CMMs are separated from BAL, is the focus of this article, stressing that market option three analysis is out of the scope of the article because the BAL market belongs to frequency ancillary service. In fact, a realization of option 3, which requires combination and coordination of frequency and non-frequency services, deserved to be discussed separately.

CMMs can offer three services to DSOs and TSOs, including Short-term, operational, and long-term services. Buyers can designate to procure their desired service from its relevant market based on their needs. In the following subsections, three services are defined and described.

4.1. Short-term

A short-term service is recommended when a grid operator is relatively sure about congestion for the upcoming day. In practice, by getting closer to the actual operation time to have a better forecast, DSOs can predict potential congestions for the coming day throughout their networks using their grid tools (e.g., congestion forecast). Congestions with a high level of certainty are then supposed to be addressed through short-term CMM. The short-term CMM is the marketplace where flexibility needs to match scheduled re-profiling (SRP) bids of flexibility service providers (FSPs). SRP is the obligation of the flexibility to modify the demand or generation at a given time to benefit flexibility buyers [53,54]. Therefore, flexibility buyers should be sure enough to participate in the short-term CMM as procurement of SRP products entails activation, which means the SRP price is the sum of flexibility reservation and activation. On the flexibility provider's side, SRP bidding on the relevant market could happen with the assumption that the bid, if traded, have to be activated according to the specified parameters of the offer (e.g., activation time, duration, volume, direction, etc.). To reduce the risk of being penalized, the FSP should make special arrangements in its portfolio to assure smooth delivery of flexibility. For instance, by adding a hard constraint (due to a previously traded SRP bid) to the bidding optimization, the upcoming biddings do not disturb the earlier bid.

4.2. Operational

Operational service can be used whenever a grid operator is unsure about congestion occurrence in the upcoming day. In this situation, a conditional re-profiling (CRP) product is used. CRP is described as when the flexibility seller must have a capacity to satisfy the traded flexibility with a specified demand or generation profile modification at a given period if the buyer requests it in real-time [54]. Therefore, unlike SRP, payment in the settlement process is made in two stages in CRP: capacity reservation and activation. In other words, if grid operators, due to their congestion forecast uncertainty and cost management, are not willing to buy SRP, they can be on the safe side by reserving capacity in operational CMM. Deciding whether to choose SRP or CRP based on certainty is complicated because sources of uncertainty could be errors perhaps interrelated, such as weather, load, and production forecast. Therefore, drawing a line between SRP and CRP according to certainty involves several factors, including DSO's experience.

Fig. 4 visualizes the price level estimation of SRP and CRP. As grid operators are always inclined to minimize their congestion management

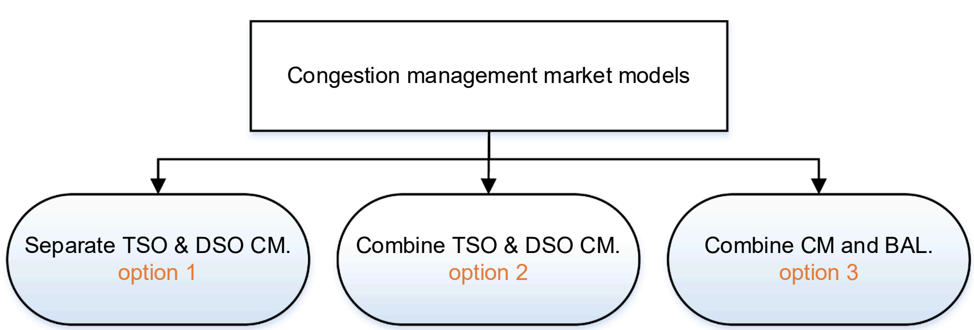

Fig. 3. CMM models.

Fig. 4. SRP and CRP price difference.

costs, CRP reservation is the cheapest product, as shown in the figure. However, if CRP is activated, it often becomes more expensive than the SRP product[12]. Hence, it is a decision-making problem for grid operators to pick the appropriate product based on their needs and certainty levels. Besides, from a portfolio management perspective, it is also a decision-making problem for FSPs to optimally distribute their available flexibilities into SRP and CRP products of CMMs, among other markets.

4.3. Long-term

For the flexibility needs, which can be foreseen a long time in advance depending on the regularity of the market operation (e.g., annually, seasonally, monthly or weekly), the long-term CM service can be used. The grid operators are expected to assess the flexibility needs' outlook based on the scheduled maintenance (M)/construction plans, their grid's seasonal hosting capacity (HC) changes, expected load/production changes, etc. The naming of the long-term service is (HC & M), which stems from grid operators' hosting capacity and maintenance needs. HC & M product is similar to what has been explained for CRP. The capacity reservation happens when the market operates (e.g., a week ahead), and the activation decision should be made a day ahead of the real-time operation. As mentioned, long-term CMM lead time varies from an annual to a weekly market, depending on the national-level regulations, needs, and stakeholders' considerations. For instance, in Finland, long-term CMM may be synchronized to co-occur with the frequency containment reserve (FCR) market [55] operating once a year in Finland. In contrast, it could be so that the resultant stakeholders' votes incline toward a weekly long-term CMM due to lower prediction errors.

It is worth discussing the features of long-term CMM concerning their lead time because stakeholders' behavior varies when lead time is maximum (e.g., annual market) compared to the situation that the lead time is minimum (e.g., weekly market), for instance. From traders' uncertainty level standpoint (due to prediction error), the longer the lead time, the higher the risks because neither the flexibility buyers nor sellers can be sure enough about their needs and capabilities a long time in advance (e.g., annual market). Therefore, a long lead time CMM may cause market players to behave conservatively. For instance, a DSO in annual CMM procures flexibility (for certain hours of the day) during winter due to dominant heating loads; however, the procured flexibility often remains untouched due to an unprecedented mild winter.

On the contrary, a longer lead time can lead to revenue security for FSPs and can be a more reliable solution for grid operators because, close to the real-time operation, the short-term and operational services might be unavailable or too expensive. Also, gaming that is a concern in low liquid markets like CMMs is reduced by leveraging longer lead-time services [12,16].

From DSOs' perspective utilizing the network reconfiguration as a long-term solution to CM (i.e., state changes of switches are done manually), it seems beneficial to synchronize the network switching state with the operation of long-term CMM to combine both CM solutions efficiently. Since the network reconfiguration is usually done seasonally or even monthly (for manually operated switches), a shorter lead time for long-term products is beneficial. The raised discussion over network reconfiguration is not valid if fully automated switches manage congestion in real-time network operation because long-term CMM timing does not match real-time CM. One additional point is that a short lead time (e.g., weekly CMM) risks being more influenced by a pre-established and robust market like DA or ID markets than a seasonal CMM. In that situation, the flexibility price possibly soars in long-term CMM because whether the DA market absorbs a significant portion of service providers' flexibilities (due to any reason) or the DA market attracts all available flexibilities in the worst-case scenario. In an optimistic analysis, flexibility value might fall in the DA market, and FSPs prefer to benefit from long-term CMM. In a final analysis, a shorter lead time of CMM raises the chance of being more influenced, whether positively or negatively, by concurrent markets (e.g., wholesale markets) because CMM is negligible in size compared to them.

Concerning the current status of markets in Europe, Piclo Flex is the only market operating in the UK that is leveraging a long lead time for its flexibility services. The lead time in Piclo Flex is up to 7 years to guarantee a long-term income opportunity for FSPs. It is worth mentioning that there is no real-world example of market options 1 and 2 and the way they are formed in Section 5. In fact, those two options have been designed to combine the advantages of the flexibility markets in Europe and reduce their problems. For example, the idea of long-term CMM comes from the fact that liquidity in the short-term and operational CMM can be negligible, and one way to stay immune from it is to leverage long-term services similar to what is done in Piclo Flex. Since PicloFlex does not have short-term and operation CM features, to increase the possibility of receiving bids from intraday market for CM similar to the work done in INTERRFACE Baltic-Nordic demonstration and NODES, GOPACS, and Enera, short-term and operational services were added to the long-term service. In other words, the market design in options 1 and 2 combines the approaches of flexibility markets and research projects to enhance the quality of the market design and reduce the problems.

5. Analysis of various market structures of CMMs

Fig. 5 consolidates the products within the services of CMMs. The three services that reflect the current needs of flexibility buyers should be addressed through appropriate CMM models where the markets are auction types. The target is to analyze various aspects of CMMs associated with design and implementation. A selected market model should correspond to stakeholders' current needs and consider compatibility (i.e., timing) to the established market places as DA and ID markets. It should be stressed that CMM design could be different depending on many factors: national and EU-level regulations, infrastructure condition (e.g., distribution network automation level, IT system readiness (i.e., software), level of grid operators' needs (i.e., dependent on network's strength)), the dominant source of congestion problem (i.e., over-penetration of solar generation, wind, etc.). Therefore, the current article does not propose a unique market model that fits everywhere in the EU; instead, it tries to open a discussion concerning relevant aspects of CMMs, hoping that the member states' CMMs experience fewer modifications and try and error process eventually.

Before entering market structures and their features, it is worth discussing the prequalification process.

The prequalification process ensures that the delivery of a particular product can actually happen without causing a problem for the grid. This concerns the abilities of the FSPs and the flexibility resources contracted to it, in addition to the grid operators where the resources are connected to their grid. Atleast two prequalification processes, including grid and product prequalification, are required [27]. As explained in Section 3, product prequalification ensures that flexibility products can actually be activated as FSP claims. Grid prequalification allows grid operators to ensure that any undesirable situation does not occur in any involved networks while activating the flexibility of an FSP.

Grid and product prequalification happens once for an FSP's

[12] Historic bids of Piclo Flex market show that activation price often vary between 5 and 30 times the value of reservation [57].

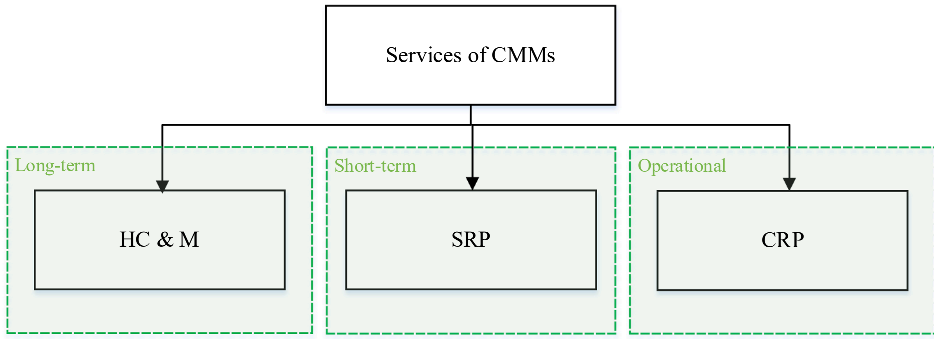

Fig. 5. Services of CMMs.

flexibility resource (or periodically, like once a year) which is then stored in the flexibility register (FR). FR aims to gather and share relevant information on flexibility resources. FR could be used for different processes within a market, such as prequalification, validation, activation, monitoring, settlement, etc. Its benefit, particularly for a grid operator, is to have visibility on which flexibility resources are connected to their grid, so they know what resources they potentially have available at all voltage levels when solving congestion.

Since grid and product prequalification happens once for a resource, under some circumstances (e.g., network topology change), activation of a resource's flexibility still might harm an involved grid operator (i.e., causing another congestion). In addition to the product and grid prequalification, market prequalification is required in the market process before any bid gets traded. In fact, market prequalification is the last stage before any bid is accepted in the market because grid prequalification might not consider the dynamics of the grids.

5.1. CMM model- option 1

The CMM model based on option 1 introduces a separate CM process for DSOs and TSO, meaning that two MOLs are formed separately for each service, one for DSOs and another for TSO. As there are two services, including short-term and operational, the number of MOLs becomes four (regardless of long-term CMM). As shown in Figs. 6–8, market option one can be implemented in at least three different manners. Fig. 6 shows the situation where DSO CM is prioritized to TSO CM regarding gate opening time (GOT) and gate closure time (GCT), while Fig. 7 illustrates the opposite situation where TSO CM is served first, followed by DSO CM. Finally, the simultaneous operation of DSO and TSO CM is represented in Fig. 8.

5.1.1. Option 1-1

According to option 1-1, as shown in Fig. 6, the market structure defines that the short-term CM for DSO operates first, followed by TSO CM in a time-sequential manner. In other words, DSOs' CM is prioritized to TSO CM in terms of the operation time window. The GOT of the DSOs' CM and Intraday market is proposed to start simultaneously at 15:15. Once the DSO CM market is opened, based on the day ahead market results (i.e., to acknowledge the DA electricity price as it influences the behavior of price-sensitive loads and generations), weather forecast, etc., DSOs, by utilizing their congestion forecast tools, are supposed to foresee congestions throughout their network for the upcoming day. The DSOs then forward their predicted congestions in flexibility need requests to the DSO CMM. The market then informs the flexibility providers about the current needs. The attributes of the flexibility needs could be flexibilities location, direction, time, duration, volume, etc.

Once the DSO CM market receives the flexibility bids, the market operator passes the bids through the market prequalification filter to assure that the bids do not harm other parts of the network belonging to nearby grid operators. For instance, as the system balance should be perfectly maintained all the time, to offset the system-level impacts, activation of flexibility requires counter activation of flexibility (with similar features) in a network area outside the congestion zone. The product prequalification mechanism enables the network operators hosting the counter activation of flexibility to confirm that the intended flexibility trade does not disturb their network operation. In fact, the market prequalification provides the chance for coordination among grid operators; otherwise, decisions should be made with higher uncertainty and with reduced flexibility and grid capacity.

After the market prequalification process, the filtered bids create a MOL for the DSO use. The DSO selects the most cost-effective bid and

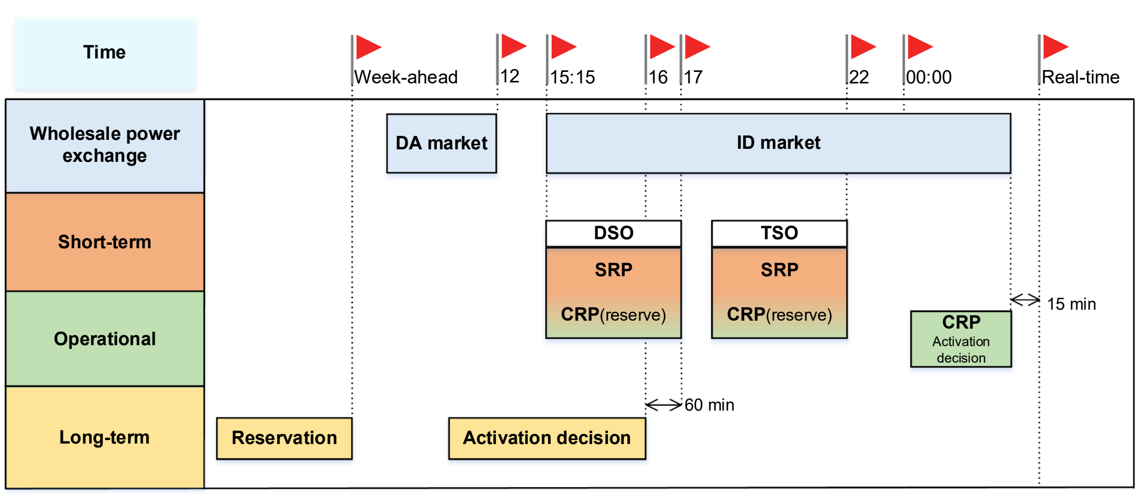

Fig. 6. Market structure of option 1-1.

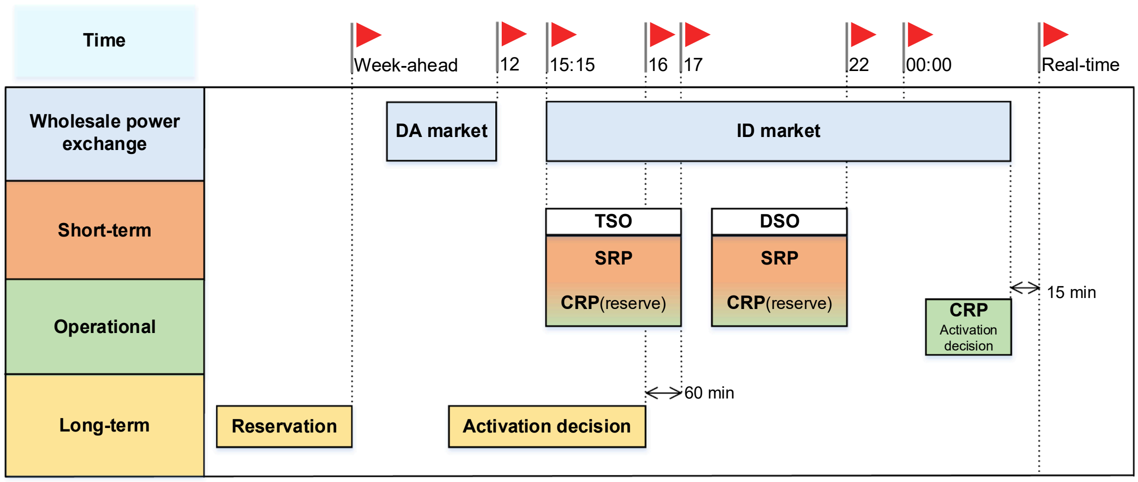

Fig. 7. Market structure of option 1-2.

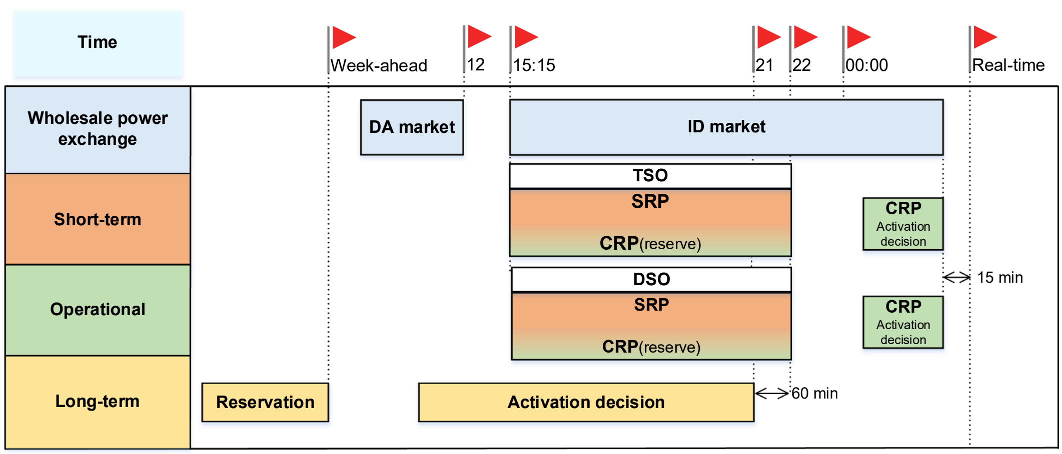

Fig. 8. Market structure of option 1-3.

informs the CMM shortly after GCT (at 17:00). It should be noted that the bid selection process of the DSOs (e.g., criteria, methodology, etc.) should be transparent for all market actors to create a trusted relationship between flexibility buyers and sellers. Therefore, the reason for the bid rejection should be cleared to the FSP by CMM to facilitate market learning. In addition, the neutrality of the market operation is enforced by transparency.

After the DSO CM closure, the TSO CM market is opened. A similar process happens in the TSO CM market. As shown in Fig. 6, it is proposed that the TSO CM's GCT is at 22, when shortly after that, the flexibility providers are informed about the market clearing results by the market operator.

As explained in Sections 3.1 and 3.2, regarding flexibility products, SRP in short-term CMM entails reservation and activation of flexibility, whereas CRP in operational CMM separates reservation and activation. Therefore, in CRP, the responsible FSP should be notified whether the grid operator wants to activate the bought reserve. As shown in Fig. 6, since CRP activation usually cannot happen immediately, a minimum 15 min lead time has been considered between activation decision and real activation of the resource to facilitate technical issues associated with flexibility activation (i.e., flexibility resource selection, aggregation, bid optimization in subsequent markets, etc.). In addition, 15 min lead time enables technically less demanding/costly communication and automation system for flexibility. Also, potentially more flexibility resources meet the requirements because they do not need to be available immediately, and therefore, thermostat-controlled loads may be utilized more efficiently, for example.

Concerning HC & M product, the chosen long-term CMM operation is weekly, so the grid operators, based on their assessment concerning hosting capacity changes of their network and maintenance schedules, are expected to forecast their flexibility needs and share them through long-term CMM. Once the HC & M product is reserved through the market, then the responsible FSP should be informed a day ahead of real-time operation if activation is needed. As proposed in Fig. 6, the long-term CMM's GCT is 60 min earlier than the GCT of operational and short-term CMMs because it allows FSPs to reuse their previously reserved flexibility if the buyer does not make an activation decision. The reason behind not activating long-term flexibility can be at least:

- Congestion is not expected, and flexibility can be utilized in any market (e.g., intraday)
- Congestion is expected; however, the long-term flexibility is not in the desired location; therefore, SRP or CRP is preferred.

5.1.2. Option1-2

CMM based on market option 1-2, as shown in Fig. 7, prioritizes the TSO CM, unlike market option 1-1, where DSO CM was the first CMM. The prioritization may lead to a more liquid TSO CMM compared to DSO CMM. Since there are already some mechanisms for TSOs such as MS in the day-ahead market and utilization of balancing market for CM, DSOs are the stakeholders that are more vulnerable due to the absence of an established mechanism for CM.

5.1.3. Option 1-3

Regarding market option 1-3, as shown in Fig. 8, both DSOs and TSO CM markets operate simultaneously but separately, providing an equal chance for grid operators to access their desired flexibility. In below, the pros and cons of three implementation ways of market option 1 will be presented.

5.2. Features of options 1-1, 1-2, and 1-3

5.2.1. Advantages

Whenever the CM market of DSO and TSO is separated, the product design becomes more flexible, reflecting more accurate DSOs and TSO needs in contrast to the "one size fits all" approach in a fully integrated TSO & DSO CM markets (i.e., option 2) [27]. Since the product design becomes more localized (at the DSO level) when grid operators' markets are segregated, small market parties with limited resources can readily participate due to lower entry barriers. Otherwise, they might not fully utilize their flexibility. Minimum bid size could be one example. TSOs' needs in terms of flexibility volume are higher than the DSOs. If the min bid size is small enough to fit the needs of DSOs, the TSO is required to buy several flexibilities from the market to satisfy its need.

On the other hand, if the min bid size is large enough to meet the needs of TSO, it might be useless for DSOs. The solution could be a compromised volume that can reasonably satisfy both sides. Another solution is to have a CMM without a standardized product with a design philosophy different from the standardized product, like NODES market products. It should be mentioned that a CMM with non-standardized products is more flexible to buyers' needs; however, aggregators bidding seems more complex because each bid could have unique constraints. Further discussion and analysis about differences between standardized and non-standardized flexibility products are recommended for future studies.

As another advantage of separated CMMs, adjustments to the flexibility product can be made without mutual interactions of TSO and DSOs because of separated governance over the CM markets. Minor and major modifications are required over the years to keep the flexibility product useful for the buyer and attractive for the seller. In other words, since the stakeholders' needs are dynamic, the flexibility products must be evolved.

5.2.2. Disadvantages

One of the downsides of separating DSO and TSO CM markets is that a grid operator's flexibility trade can cause congestion for an involved grid operator if proper coordination is not in place. When two markets are in series, such a scenario could happen for a grid operator whose CMM operates first (e.g., DSO in market option 1-1). Although coordination between flexibility buyers is required irrespective of the market structure, it seems easier to coordinate within the market process than outside it.

Another noticeable point is that the grid operator with an earlier CMM may feel uncertain about the upcoming CMM trades' adverse effects on its network. Therefore, the grid operator may procure extra flexibilities to have a more extensive operation margin leading to unused flexibility. For instance, DSOs in market option 1-1 may procure extra flexibilities for the sake of compensating for possible adverse impacts of TSO's actions in its CM market. On the other hand, TSO may allocate less transmission capacity to spot markets to avoid congestion by DSOs actions in CMMs. In this condition, TSO and DSOs actions result in higher CM costs. The mentioned problem is less probable in market option 1-2 as the traded volumes for DSO CM are often less than the amount that can cause a TSO problem. Nevertheless, in option 1-2, TSO's CMM most likely receives the most flexibilities and endangers the DSO's CM in terms of liquidity and CM costs.

Another disadvantage of separated CM markets is that different market platforms are needed due to different bidding systems, which is not favorable from an IT and communication perspective. Besides, having several market processes leads to market fragmentation and makes the bidding harder for FSPs than having one integrated market process for DSOs and TSO.

5.2.3. Special features of each implementation

Apart from the general advantages and disadvantages expected from the market structures where DSO and TSO CM are separated, some aspects specialized to each implementation of market option 1, which will be discussed in the following two paragraphs.

In market option 1-1, since the DSO CM is served first, it is likely that FSPs allocate their flexibilities firstly at DSO CMM because its GOT is earlier. In other words, it is expected that market option 1-1 provides higher liquidity to DSOs compared to market option 1-2.

Market option 1-3 receives the mentioned benefits of separating CM markets for DSOs and TSOs. In addition, as both markets are open simultaneously, it could facilitate synergies between buyers, leading to more efficient use of flexibility. About downsides, adverse impacts of the flexibility trade of one CM market on the previous CM market (option 1-1 and 1-2) still exists similarly in option 1-3 because CM markets of DSOs and TSO function at the same time and the grid operators are not fully aware of the ongoing flexibility trades in a parallel CM market especially if proper coordination is not in place. In this situation, grid operators may compete for flexibility procurement leading to high CM costs. Also, competition in CM markets in its negative sense (without coordination between buyers) may lead flexibility buyers to only use long-term CM services, meaning that flexibility is locked and not used where it creates the most benefit.

5.3. CMM model- option 2

A market design based on market option 2, as shown in Fig. 9, includes one MOL for both DSOs and TSO CM. Flexibility procurement is dependent on how the coordination and agreement between buyers are made. As there is one market process for each service, grid operators' concerns regarding adverse impacts of trades in an upcoming CMM are eliminated because of TSO-DSO coordination in the market. Another positive aspect is that one gate is introduced for CM (single-entry gate), facilitating the market participants and probably increasing liquidity. Also, from information technology (IT) and communication viewpoints, it is more efficient to have one IT platform for each service than market option 1-1, where each service requires two separate IT systems.

One downside of market structure 2 is product design. If the products are standardized, flexibility product attributes should be agreed upon between DSOs and TSO, which can be challenging because their needs often are not on the same scale (i.e., MW, kW, etc.). Product design is a compromise that can consider grid operators' most critical needs and skip the insignificant ones. Besides, as grid operators' needs change over time, the market must evolve accordingly from a general viewpoint. Therefore, the agreement on market structure, operation, product design, etc., should be repeated periodically, which is time and energy-consuming because agreeing can be difficult when the needs are not necessarily in the same direction.

It is worth mentioning that flexibility product design in market option 2 is more challenging than option 1; however, even in market option 1, a very different level of the needs among DSOs might cause a problem in flexibility product design. Therefore, from grid operators' perspective, the difficulty in flexibility product design is proportional to the gap among grid operators' needs, such as flexibility need volume, minimum bid size, aggregation level, and location.

Table 4 summarizes the features comparison between market designs based on options 1 and 2.

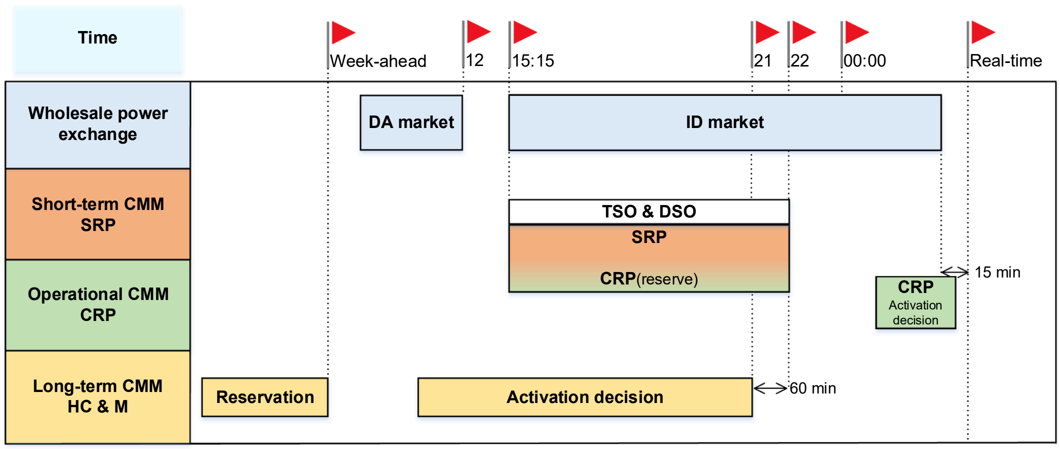

Fig. 9. Market structure of option 2.

Table 4
Features' comparison of market options 1 and 2.

Feature	More flexible product design	Lower entry barrier for small scale flexibilities	Separate governance of DSOs and TSO	Higher liquidity
Option 1	√	√	√	–
Option 2	–	–	–	√
Feature	TSO and DSO coordination integrated into the market process	Easier bidding for FSPs due to dealing with single-entry gate (i.e., one IT interface)	One IT platform for TSO and DSOs	Clear CM and balancing cost separation
Option 1	–	–	–	√
Option 2	√	√	√	√

6. Conclusion

Various market models could be thought of when designing a CMM from scratch. Therefore, the article attempts to clarify some of the essential aspects related to CMMs, such as understanding the congestion problem, requirements for using CMMs, the market's role in CM, current ways to tackle congestion at the distribution and transmission level and then analyzing possible CMM structures. In addition, in this article, CMM aspects are seen from different stakeholders' perspectives to have practical discussions because a thriving market results from synergy and shared understanding between stakeholders. Besides, to enhance the article's practicality, the approach of pioneering flexibility markets in Europe, including Enera, GOPACS, NODES, and Piclo Flex, is considered in the discussions. Except for GOPACS that procures flexibility from ETPA, non of the flexibility markets in Europe are yet fully commercial, which makes the need for the current article with a holistic approach necessary.

The real-world congestion management of a DSO showed that grid operators tend to choose traditional CM alternatives like reinforcement for their congestion problems, perhaps without thinking about a second solution. Investment in the network as a passive solution is understandable from a reliability perspective because grid operators have to supply the end customers with no interruptions. This responsibility makes them more conservative in their decision-making. Nevertheless, with solutions based on flexibility as a complementary alternative to traditional options, cost-effectiveness can be increased. In the raised example of Section 2.4, around 548 k€ could have been saved using a flexibility-based solution to postpone the reinforcement. Reinforcement deferral provides an opportunity to make full use of grid components' lifetime. In addition, it gives the grid operators precious time to plan for the future when more data (e.g., data of city planning, renewable penetration, etc.) are available.

It was proposed that quality attributes such as cost-effectivity, reliability, durability, feasibility, and environmental protection are considered when evaluating various CM solutions. For instance, a solution like reinforcement could have acceptable reliability, durability, and feasibility; nevertheless, it might harm the environment (e.g., clearing forest). In contrast, CMM utilization may less harm the environment, but it might not be as reliable as reinforcement for a grid operator. The mentioned quality attributes help to compare different CM solutions considering that evaluating different CM solutions is case-dependent.

It was proposed that at least four preconditions should be met before considering CMM as a CM solution. CM needs from grid operators, grid operator's readiness in network monitoring and control, flexibility providers' readiness in bidding and flexibility delivery, and finally, proper regulations supporting the market in its all stages (e.g., from a contract between aggregator and customer to settlement) are four conditions for a fully functioning market. Once those four conditions are met, CMM could be considered a CM solution.

In this article, a discussion concerning the CMM role in CM was provided. The CMM role in CM could vary depending on the network's state at the time of market utilization. Avoidance of renewable energy curtailment (e.g., wind power in Germany) and reinforcement deferral could be two common cases where CMM can play an active role. LFM as an extension of CMM could be utilized for portfolio optimization of aggregators and retailers, peer-to-peer (P2P) trading between prosumers, and trading between energy communities and microgrids. In addition, LFM availability impacts investment made in relevant services and technologies, such as expanding or introducing flexibility contracts with customers, improving automation systems, building new flexibility systems (e.g., stationary battery), etc.

Transparency, neutrality, reliability, and liquidity as desired market properties that should be reinforced while designing a CMM. Four market designs were proposed in the article, including options 1-1, 1-2, 1-3, and 2. The influential market design factors are GOT, GCT, product design (i.e., lead time, flexibility product attributes), coordination between grid operators, CM services (e.g., short-term, operational, long-term), IT-related issues, flexibility in product design (i.e., separated CM and BAL), market entry barrier, bidding difficulty (i.e., single-entry gate), governance separation between DSOs and TSO over market design, etc.

CRediT authorship contribution statement

Mehdi Attar: Conceptualization, Methodology, Investigation, Writing – original draft. **Sami Repo:** Supervision, Project administration, Funding acquisition, Writing – review & editing. **Pierre Mann:** Writing – review & editing.

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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