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Congestion management in electricity distribution networks: Smart tariffs, local markets and direct control

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ABSTRACT

Increasing peaks from high-power loads such as EVs and heat pumps lead to congestion of electric distribution grids. The inherent flexibility of these loads could be used to resolve congestion events. Possible options for this are smart network tariffs, market-based approaches, and direct control of flexible loads by the network operator. In most instances, these approaches are looked at in isolation, without considering potential connections and trade-offs between them. In this contribution, we aim to bridge this gap by presenting an overarching design framework for congestion management mechanisms. We classify proposals based on design choices and qualitatively discuss their benefits and risks based on an extensive literature analysis. As there is no one-size-fits-all solution, we map possible risks and discuss the pros and cons of different mechanisms for various problem types. We caution against using market-based mechanisms for local congestion, as they can be susceptible to undesired strategic behavior of market actors.

1. Introduction

Background

More Distributed Energy Resources (DERs) like PV cells, EVs, batteries, and heat pumps are connected to the electric grid daily. These resources help to decarbonize the energy system. Still, they also bring new challenges for electric distribution networks: high power usage or feed-in from these sources can lead to overloading or voltage problems, also called network congestion.

Upgrading the network to the point where it could accommodate all these new loads and generators is not an option: it would be very costly and likely not be possible at the required pace. However, it is also unnecessary: In many cases, these new DERs are highly flexible: EVs, batteries, and heat pumps do not need to run at a specific time, but instead, they need to fulfill an energy requirement over a time interval. PV feed-in can be curtailed or absorbed by batteries and other uses. Therefore, it is possible to flatten the peaks created by these energy resources and ensure that the total load stays within safe network limits. Thus, a much more efficient solution is to resolve grid congestion more smartly by using this flexibility to flatten network peaks (Spiliotis et al., 2016).

The main options for doing this are: making network tariffs smarter, using local markets for redispatch, or directly controlling loads that sign up for demand response programs. In the latter two cases, the congestion management method is added to the existing network tariff, which can create confusion around the relationship between congestion management and network tariffs. In general, the primary function of tariffs is to allocate the costs of building and maintaining the network to its users (Reneses and Ortega, 2014; Hennig et al., 2022a). As a secondary function, these tariffs can incentivize more intelligent network use. In this case, they are also called "smart" tariffs. For congestion management, the problem is how to make the best use of flexible loads to remove congestion. This relation is shown in Fig. 1. These methods are mainly discussed in isolation, and how they relate is often unclear. The lack of clarity may lead to uncertainty and delays in preparing appropriate congestion management strategies. These delays can be costly: failing to anticipate what is needed to manage congestion may lead to forceful curtailment of loads, overload of grid equipment, or inefficient solutions. Network operators, regulators, and other stakeholders need to understand the possible solutions to decide on their strategies to be prepared for a future where congestion is becoming much more common.

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Acronyms

BRP	Balance Responsible Party
CEER	Council of European Energy Regulators
CLS	Capacity Limitation Services
CM	Congestion Management
CPP	Critical Peak Pricing
DER	Distributed Energy Resources
DG	Distributed Generation
DLC	Direct Load Control
DLMP	Distribution Locational Marginal Prices
DSO	Distribution System Operator
EV	Electric Vehicle
LFM	Local Flexibility Market
LV/MV/HV	Low/Medium/High Voltage
NCPC	Network Coincident Peak Charges
PV	Photo Voltaic
QoS	Quality of Service
ToU	Time of Use
TSO	Transmission System Operator
VCG	Vickrey–Clarke–Groves auction

Contribution of this article

In light of these challenges, the contributions of this article are:

1. To structure the literature by investigating the design choices of congestion management (CM) approaches. Based on the design choices, we divide CM methods into four families: static and dynamic access prices, Local Flexibility Markets (LFMs), and direct control methods.[1]
2. To qualitatively discuss the benefits and drawbacks of these types of methods.
3. To consider the influence of design choices on performance and risk.

The leading search terms to identify relevant literature were "congestion management", "network tariffs", "dynamic tariffs", "flexibility markets", "demand response", and "load curtailment". We also used snowballing from these articles and web searches to identify further relevant literature and industry reports of related stakeholders. These articles were synthesized to identify the possible design choices at a higher level and reflect on the impact of these design choices on performance and risks.

The questions addressed in each section are as follows. Section 2: What types of congestion problems occur in electric distribution networks? Section 3: What are the required objectives of a successful congestion management (CM) mechanism? Section 4: What are the crucial design choices for CM mechanisms? Section 5: Which are the main proposals for CM mechanisms, and how can they be classified based on their design choices? Section 6: What are the benefits and drawbacks of each method concerning the objectives, what risks exist, and how do design choices influence performance and risks? Section 7 concludes the article.

2. Congestion problem specification

There is a wide variety of congestion problems regarding their spatial localization, timing and predictability, type of network limitation, and external circumstances. These parameters strongly influence the types of solutions that apply to the problem. We give a brief overview of the different options.

In terms of the spatial location of network problems, the options range from highly localized to spread out over larger areas:

- LV feeders or transformer stations for up to about a hundred households,
- MV feeders or transformer stations for hundreds to thousands of households,
- HV transmission cables or transformer stations for 10,000 or more households,

For timing and predictability of the problem, the main question is: Does the congestion problem occur at a relatively regular and, on average, predictable time or at random times? In the former case, it is likely related to a corresponding increase in firm loads during peak hours in the network, e.g., the evening hours when many people come home from work. In the latter case, it is likely related to external factors such as outages and maintenance events, low wholesale energy prices, or extreme weather events. The Council of European Energy Regulators (CEER) (2020) distinguishes these two types as: "structural" congestion which is regular and predictable long in advance, and "sporadic" congestion which is irregular and predictable only in the near term or near real-time.

In general, the predictability of the problem may be better for larger spatial areas, as random fluctuations tend to average out over larger samples. Thus, larger MV substations may be associated with a higher degree of structural congestion and a lower degree of sporadic congestion relative to smaller LV-network feeders, where overload can occur due to relatively few EVs charging at full power. Nevertheless, this general tendency does not rule out predictable congestion of highly loaded LV feeders, e.g., in the case of industrial sites with well-known schedules or residential areas with excessive solar PV generation.

Regarding the type of network limitation, we focus here on mechanisms that deal with the thermal load limits of network equipment. This limitation is often the most pressing one, and the one for which most proposals have been made, according to Anaya and Pollitt (2021). Other types include voltage and reactive power limits (Anaya and Pollitt, 2021; Tabors et al., 2017). A further distinction for thermal load limits can be made by the "direction" of congestion: Is it caused by too much load on the feeder or too much feed-in?

Dronne et al. (2020) review several external circumstances and how they may impact the design of new CM solutions. In addition to the type and depth of congestion, they consider the existence of and need for new flexibility resources, the organizational structure of network operation (e.g., number of customers per DSO and interactions between DSOs with each other and the TSO), the regulatory landscape and pre-existing approaches for CM. All of these may influence the choice of the solution.

Unfortunately, data on the specifics of congestion problems is hard to find. At the European level, the JRC (Prettico et al., 2021) and the European Commission (European Commission - General Directorate for Energy, 2015) have undertaken and published data-gathering exercises from DSOs across Europe. These reports include aggregate service quality measures like SAIDI and SAIFI. Unfortunately, they do not include detailed information on existing and anticipated congestion problems: their type and depth, localization, and timing. This information would benefit academic and regulatory purposes to develop fit-for-purpose solutions.

3. Objectives for congestion management

The main objective of CM is to flatten network peaks such that all network constraints are respected. However, there are also several related objectives. These include reliability, social costs, non-discrimination, complexity, and allowing the use of flexibility for other purposes.

[1] Standard network tariffs belong to the static access price category, while smart tariffs can integrate aspects of dynamic aspect prices and direct control.

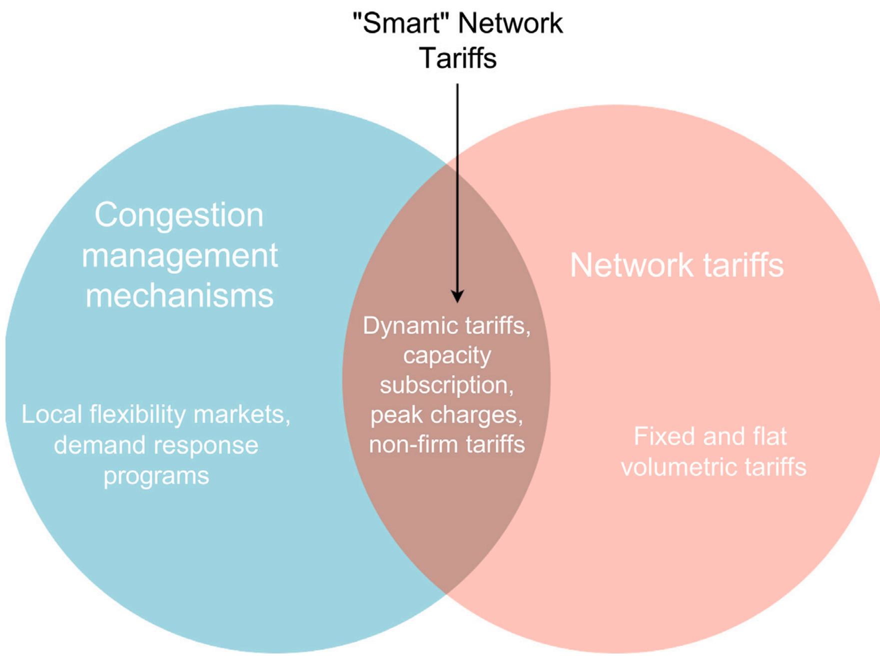

Fig. 1. The relation of congestion management and network tariffs.

Reliability. Thermal load limits and voltage constraints of all network nodes should not be exceeded. Ideally, this should always hold, though, in practice, minor violations of thermal load limits and power quality can be acceptable (Haque et al., 2016).

For this objective, it is necessary to take a holistic perspective of congestion in space and time. A mechanism that merely moves congestion from one point in space and time to another (also called *displacement* or *spillover*) or does not fully resolve it would not be reliable.

Social Costs. This objective concerns the costs of complete congestion removal. In some mechanisms, the network operator has to bear these costs, while in others, it obtains "congestion rents" (e.g., in dynamic network pricing). A societally cost-efficient mechanism will remove congestion by shifting or curtailing those loads with the lowest willingness to pay at a given moment. These are typically EVs or heat pumps with much slack in their constraints. Furthermore, the mechanism should only lead to network costs around the marginal cost of shifting these loads to another time. This marginal cost can often be related to the wholesale price difference between the congested times and the next-lower price time steps.

If prices are significantly higher than that, the network operator overpays flexibility providers or charges excessive congestion rents (depending on the mechanism, see Section 4). The first case is problematic because these expenses must be recovered from the general user base. In contrast, the second case is problematic as it means that network capacity would not be used to the extent possible when it is highly desired. Ideally, congestion should be removed by shifting only those necessary loads with the lowest cost of moving and setting prices close to their marginal cost of shifting.

Non-discrimination. On average, the congestion management mechanism should not treat network users differently. However, since different network areas are congested to different degrees, some form of discrimination is inherent to the problem. Discrimination can be mainly due to price differences, where consumers in congested areas pay higher prices on average, or quality-of-service (QoS) differences. This situation occurs because some CM approaches are based on limited curtailments of flexible loads signed up for contracts with interruptible connections. Users with such agreements in congested areas will be curtailed more often than in non-congested areas.

One possibility to resolve the dilemma could be to tie the price discrimination to the QoS discrimination: users of flexible loads that are curtailed more often could receive compensation through the CM mechanism accordingly.

Complexity. A common practical problem is that elaborate solutions are often difficult to implement and understand for users, which can hamper their effectiveness in real-world conditions, even when they are theoretically highly efficient. Therefore, CM mechanisms should be easy to implement and understand for all participants. The rules and parameters of the mechanism should be transparent and be communicated to users. It should also build on existing network codes and ensure that new functions are thoroughly tested and verified to work under real-world conditions at the required scale.

Flexibility for other purposes. If possible, the congestion management mechanism should not prevent flexibility providers from making it available for other purposes as well, such as services for the Transmission System Operator (TSO) and Balance Responsible Parties (BRPs) portfolio management (Ramos et al., 2016; Stawska et al., 2021).[2]

Significant in this regard is the further enhancement of TSO-DSO coordination. As analyzed in Martín-Utrilla et al. (2022), TSOs and DSOs often have overlapping needs for flexibility products. Some of these may be satisfied by common market mechanisms, while others may have to be satisfied by non-market-based mechanisms, e.g., due to low liquidity. Either way, it is essential to ensure that mechanisms activated by the TSO or DSOs do not adversely affect the operation of the other party (DSOs or TSOs, respectively). Many projects are currently studying this issue in the European context.[3] For further literature on the topic, we refer to Martín-Utrilla et al. (2022).

[2] One option to fulfill this objective, is to leave some headroom between the scheduled flexible loads and the binding network constraint. For EVs, charging can be scheduled to up to 80%–90% of the rated transformer capacity. This practice allows flexibility in up and down directions for additional purposes at the TSO level or real-time portfolio balancing. It also has the added benefit of reducing operational uncertainty and costs of losses and transformer aging (Haque et al., 2016) for the DSO, as these are higher when the transformer is loaded near 100%.

[3] See CoordiNet, SmartNet, INTERRFACE and OneNet, among others.

4. Design choices of congestion management mechanisms

There is a large variety of different proposals for CM mechanisms. However, many studies or reports only present one proposal without discussing how choices in its design would influence the outcomes. Thus, in the following, we want to answer the question: What are the fundamental decisions for CM mechanisms?

Note that our primary focus is on the situation in Europe. In the EU and the UK, electricity systems have been subject to "unbundling" since the late 1990s. The formerly integrated utility companies for electricity delivery have been split up during this process. Transmission and distribution system management is now handled by independent system operators (TSOs and DSOs), while power generation has been liberalized and opened up to market competition (Meeus, 2020). For reference, we also include considerations for the vertically integrated utilities, operating in North America and other parts of the world. Not all design choices discussed here apply in all contexts, depending on the market design and the regulatory environment.[4]

4.1. Load/feed-in controlling party

Ultimately, the DSO ensures stable electricity delivery through the network which avoids dangerous network overload that could cause equipment failure. However, there is a question of how this control is achieved. The DSO has three options. The first is to directly control loads or curtail generator/battery feed-in of end-users. The second is to let end-users control their loads and generators. In this case, the DSO needs to give contractual specifications and financial incentives for users to maintain control to stay within network bounds. This practice particularly applies to large, industrial, or commercial consumers (Richstein and Hosseinioun, 2020). The third is to have contracts with aggregators to control end-user loads or generators. The contractual specifications and financial incentives are then agreed upon with an aggregator that handles many individual end-user loads rather than directly with the end-users.

4.2. DSO position: offer or buy-back of network access

This design choice concerns whether the required control is included directly in the network access conditions or whether network access is offered without tight limitations (i.e., in a way that may lead to network overload) and then effectively "bought back" by the DSO. We call this the "DSO position" and distinguish between:

- Offer: In unbundled electricity systems, the DSO already has contractual agreements that specify network access conditions and tariffs (Hennig et al., 2022a).[5] Thus, incentives to reduce network stress can be included in the access conditions offered by the network operator. These incentives can be part of the standard network tariff or separate agreements for flexible loads (Fuller et al., 2011) and generators (Anaya and Pollitt, 2015). These incentives may not always be sufficient to remove congestion, especially in static tariffs. A remedy like buy-back approaches or curtailment may be necessary in these cases.
- Buy-back: The DSO asks end-users for a "buy-back" of network access rights. There is a two-stage process to determine the final network access conditions. The DSO offers network access under its general access rules in the first stage. In the second stage, it estimates what is needed to resolve network congestion and pays users or aggregators to deliver load (or feed-in) shedding services to resolve the congestion.

[4] Furthermore, we consider only contractual forms of CM, not technical network reconfiguration, as discussed by Huang et al. (2015).

[5] Note: Similar contractual agreements exist for vertically integrated utilities. However, in this case, they are not just for distribution network access, but for all parts of the power provision chain: generation, transmission, and distribution.

The Universal Smart Energy Framework (USEF), proposed by the USEF foundation (de Heer et al., 2021), distinguishes similar perspectives from the point of view of the flexibility provider: flexibility that is steered through the access conditions of the DSO (in conjunction with other charges) is called "implicit flexibility", whereas a buy-back of network access is an example of "explicit flexibility" trading. The latter can also be traded for purposes such as TSO network management or portfolio optimization (de Heer et al., 2021; Ramos et al., 2016).

4.3. End-user position: applied loads, relation to tariff and consent

Similar to the DSO position, we can also look at contractual options from the end-user's perspective. CM mechanisms may be distinguished by the devices to which they apply. Options are:

- Applies equally to all loads and distributed generation.
- Targets flexible loads like EVs and heat pumps specifically. In practice, this requires the installation of a separate meter for these loads to be able to make a distinction in the tariff.[6]
- Distinguishes between feed-in and take-off (i.e., "up" and "down" regulation in analogy to balancing at the transmission level).

Secondly, they can be distinguished by the relation between the CM mechanism and the default network tariff.[7] The CM mechanism can replace the default tariff for these loads or apply in addition to the default tariff.

Thirdly, an essential choice for coverage of the mechanism is whether users can opt into the mechanism or not. We call these options for participation "by consent" and "by default".

4.4. Price formation

There are two possible options by which prices for network access or buy-back can be set. The first one is regulated, where the DSO sets prices for network access and congestion-related buy-back of network access in agreement with the regulator. The regulated prices can be static and fixed in advance or dynamic and responsive to network condition forecasts (see Section 4.5). This approach is the most common for "Offer"-based CM approaches.

The second option for price formation is "auction-based". Auctions are used mainly in "Buy-back" market-based proposals but can also occur in some "offer" based proposals where the DSO auctions off network capacity (Fuller et al., 2011; Verzijlbergh et al., 2014). There are different formats by which the price in an auction can be set. The most commonly used ones are:

- Pay-as-bid (Anaya and Pollitt, 2021; Ding et al., 2013; Radecke et al., 2019; Esmat et al., 2018b; USEF Foundation, 2020; Valarezo et al., 2021): market participants bid for flexibility requests from the DSO. The DSO selects sufficient bids to remove the congestion problem and pays each accepted bid exactly at its bid size. Note that this may create an incentive to bid above marginal costs for the flexibility provider, as long as they anticipate their bid is still accepted (Kahn et al., 2001; Heinrich et al., 2021).
- Pay-as-cleared (Anaya and Pollitt, 2021; Valarezo et al., 2021): Each market participant is paid the price of the marginal bid the DSO accepted.

[6] This is envisioned in a current proposal by the Bundesnetzagentur, the German regulator for the network. It foresees the installation of remotely controllable load-limiting devices, through which the network operator can curtail flexible loads to a maximum of 3.7 kW.

[7] In the North American context, the network price is typically integrated with the energy price itself. Thus, these considerations apply similarly to the complete energy price, not just the network tariff.

- Dutch reverse auction (Anaya and Pollitt, 2021): Market participants do not submit bids in this type of auction. Instead, the DSO starts with a small offer price for flexibility, which gradually increases until market participants accept the bid.
- Vickrey–Clarke–Groves (VCG) auctions and modifications thereof Heinrich et al. (2021): In VCG auctions, participants submit sealed bids, meaning that the bids of other participants are not known. The market is cleared to minimize costs for the DSO, and each participant is reimbursed proportional to the benefit they bring to the system (see Heinrich et al. 2021 for further details).

4.5. Time frame

CM methods differ regarding the time frame for determining network prices and access conditions. The options are:

- Long-term: e.g., monthly, seasonal, or yearly.
- Day-ahead or near-term (several hours ahead).
- Near-real time.

An important aspect here is the timing of determining the network access conditions relative to the wholesale energy market, especially the day-ahead market. This issue is particularly relevant for aggregators and other energy service companies active in the wholesale market on behalf of their customers. It may be easier for them to optimize their portfolio by knowing the network access conditions before trading on the wholesale market, as they can include the network constraints in their trading decisions. When network access conditions change after these entities have traded on the wholesale market, they may require intraday and balancing markets.

4.6. Spatial variation

In addition to temporal variation, there can also be spatial variation in network access conditions. The main advantage of using localized CM options is that network congestion can be targeted efficiently. On the other hand, introducing changes based on location introduces some degree of discrimination in network access (see Hennig et al. 2022a) and may adversely affect users in congested areas.

The spatial variation can also have varying degrees of granularity. In analogy to the congestion problems themselves (Section 2), the main options are:

- Whole network, transmission level
- Larger sub-zones of the network, e.g., behind the same HV/MV transformer station
- Neighborhood level (several LV feeders)
- Single LV feeder level

4.7. Further product specifications

There are many implementation details at a lower level of differentiation between different methods. We use the summary term "product specifications" for these.

Some of these specifications apply to all kinds of CM methods, while others are particular to the type of CM method. For the common ones, we identified:

Commodity: Network access conditions can be specified in terms of either the maximum capacity of network access in kW, energy transported through the network in kWh, or the cost of the connection itself.[8] In the case of capacity, there can be different bases for how it is determined. It can be the measured peak power at a user connection in a given billing period (Schittekatte et al., 2017; Ansarin et al., 2020b), a contracted specific amount of network capacity (with a penalty for exceeding this amount) (Bjarghov and Doorman, 2018; Hennig et al., 2020), or the utilized capacity of a user at the times of highest coincident network peaks (Passey et al., 2017). It is also essential to define the time over which power usage is averaged to determine network capacity usage, e.g., 5, 15, or 60 min. For example, a kettle or a microwave may have a relatively high power consumption of 1 kW over 3 min. This results in a total energy usage of 0.05 kWh. Over a 5 min interval, this would be an average power usage of 0.6 kW, over 60 min, it would only be an average use of 0.05 kW.

Tiered pricing: This method refers to a price variation per unit of commodity based on *quantity* used, which can be implemented for energy and capacity. E.g., the price per kWh may increase (or decrease) when total yearly consumption exceeds 2000 kWh and then again at 4000 kWh, and so on (Borenstein, 2016; Ansarin et al., 2020a). Similarly, the cost per kW of network capacity access may increase at 2 kW, 4 kW and so on (DNV GL, 2020; Bjarghov et al., 2022).

Firmness: Connection agreements and flexibility products can be firm or non-firm. Firm means a guaranteed fixed network capacity is available for the end-user. In non-firm agreements, the network access capacity is dynamically dependent on the network state and may be reduced during network congestion. In this latter case, specifications may also include the maximal allowable number and duration of load reductions. Examples of non-firm products include option trades in buy-back-based proposals (see, e.g., Esmat et al. 2018a, Ding et al. 2013) and activation of direct-control measures in Clean Energy Group (2021).

In addition to these common ones, some specifications apply only to certain classes of CM mechanisms. These are discussed in the next section, where we review the different classes.

5. Review and classification of congestion management mechanisms from the literature

In this section, we review CM proposals from the literature. We use a classification based on two high-level design variables discussed in the previous section to structure the review. Firstly, the load-controlling party: DSO or aggregator/end-user (the interaction and contracts between aggregators and end-users are not considered here). Secondly, the DSO position is "offer" or "buy-back" for schemes not based on DSO control. Sorting CM mechanisms by these choices leads to 3 distinct categories: Network access prices, Local Flexibility Markets (LFMs), and Direct Load Control (DLC) schemes (Fig. 2).

This classification was chosen because these categories are also commonly discussed in the literature as separate strands. A different distinction would also be possible, e.g., by time frame or commodity. However, different time frames and commodities are often discussed together in the reviewed literature, while mechanisms from different categories in the proposed classification are not. The following subsections discuss the lower-level design choices of different variations in each category.

5.1. Network access price-based methods

This category includes all CM proposals based on charges for network access by the DSO to users. There is no buy-back within these mechanisms; by default, the DSO does not directly control user loads (except for emergency curtailment). The main distinction within this category is based on the time frame: network access prices fixed over the long term are also called "static tariffs", while those not fixed are called "dynamic tariffs".

[8] The connection cost may vary by location to incentivize investments in less congested areas and recover costs for network upgrades in more congested areas (Brandstätt et al., 2011). However, this is outside the scope of this review as we are concerned more with operational congestion management, not investments.

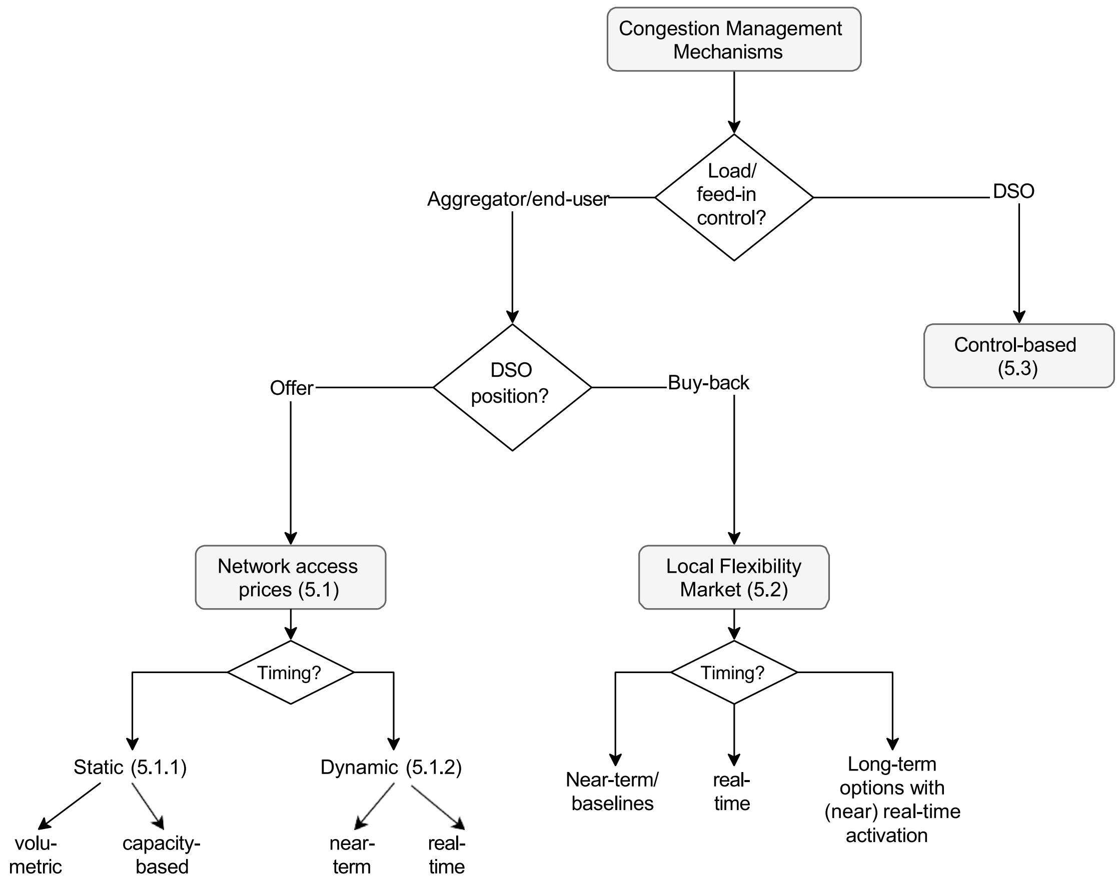

Fig. 2. Classification of mechanisms.

5.1.1. *Static network tariffs*

Standard tariffs are periodically recurring payments the network operator charges for network use. Their primary purpose is cost-recovery for network-related activities (CEER, 2020; Alba Rios and O'Brian, 2021; Hennig et al., 2022a). However, these tariffs can also perform implicit congestion management. They are usually fixed over a billing period. All of the commonly proposed variations have the following additional design variables in common: they use regulated prices, apply over a long-term time frame, provide firm access to the network (except for emergency curtailment), and do not distinguish between flexible and non-flexible loads. However, they can distinguish between load and feed-in of distributed generation (Schittekatte et al., 2017).

Being static does not mean that the charges do not vary: in Time-of-Use (ToU) tariffs, charges can vary according to a fixed schedule by time of day or season. However, this time dependence is known in advance and does not change over the billing period.

The primary distinguishing design variable for static tariffs is the commodity on which the tariff is based (CEER, 2020; Hennig et al., 2022a; Ansarin et al., 2020b; Reneses and Ortega, 2014):

- Energy for volumetric tariffs: a fee per kWh of energy delivered through the network.
- Measured peak capacity: a fee per kW for personal peak usage.
- Contracted capacity for capacity subscription tariffs: the end-user can choose different power levels (kW). Energy consumption up to the selected level is free or at a low price, while consumption above the chosen level is penalized (DNV GL, 2020; Tuunanen et al., 2016; Hennig et al., 2020).

EUniversal (2020) and Morell et al. (2021) give an overview of the current static tariffs in European countries.

5.1.2. *Dynamic tariffs*

Dynamic tariffs are network access prices adjusted dynamically based on expected or observed network conditions. In contrast to static tariffs, we find much more variation in other design variables.

Critical Peak Pricing (CPP) (CEER, 2020; Alba Rios and O'Brian, 2021; Fridgen et al., 2018): In CPP, Network prices are increased for an expected significant peak in network load, e.g., on particularly hot, cold, or sunny days. The network operator sends an advance notice a few hours to a day before the price spike occurs. The price spike is added to the default network tariff and applies to all loads equally.

Network Coincident Peak Charges (NCPC) (Passey et al., 2017; Abdelmotteleb et al., 2018): In this approach, charges are based on the network-coincident peak, not the personal peak of the end-user. Instead of a single network peak, it might also consider multiple network peaks. Furthermore, the network operator may send an advance notice before expected peaks, making this approach similar to CPP.[9]

Distribution Locational Marginal Prices (DLMP) (MIT Energy Initiative and IIT Comillas, 2016; Ansarin et al., 2020b; Tabors et al., 2017): This approach is an extension of locational marginal pricing (LMP) for wholesale power markets to the distribution level. LMP refers to price differentiation of electricity at different high-voltage transmission grid nodes. It has been applied in North American Regional

[9] To list this as a dynamic tariff may seem strange: the network access conditions and price per kW of peak contribution are actually fixed over the long term, so this approach could also be seen as a static tariff. However, the final payments under this scheme depend on when the highest network peak(s) occurs, which is only truly known at the end of the billing period and could theoretically change in real-time at any moment until then. Therefore, we favor the categorization as dynamic.

Table 1
Design space variables of dynamic access price variations.

	Commodity	Price formation	Time-frame	Loads applied to
CPP	Energy	Regulated	Near-term	All
NCPC	Capacity	Regulated	Network peak	All
DLMP	Energy	Regulated	Day-ahead or Real-time	Flexible or All
Capacity auction	Capacity	Auction, pay-as-cleared	Day-ahead or Real-time	Flexible

Transmission Operators (RTOs) grids.[10] In North America, integrated utilities deliver electricity by owning assets across the electricity supply chain: generation, transmission, and distribution. Thus, the LMP refers to the complete delivery price of electricity, including generation, transmission, and distribution charges. In the European context, DLMP is sometimes meant to include only the locational network costs (Abdelmotteleb et al., 2018), and sometimes the sum of locational network costs plus the wholesale price of energy (Huang et al., 2015; Li et al., 2014; O'Connell et al., 2012). The term "dynamic network tariff" sometimes refers to only the network-specific part, without the wholesale price component (O'Connell et al., 2012; Verzijlbergh et al., 2014).

DLMP can be set near real-time (MIT Energy Initiative and IIT Comillas, 2016; Ansarin et al., 2020b), a day ahead (Huang et al., 2015; Li et al., 2014; O'Connell et al., 2012; Verzijlbergh et al., 2014), or at intermediate steps, e.g. a few hours ahead (MIT Energy Initiative and IIT Comillas, 2016). As can be seen from the cited publications, near real-time DLMPs are more commonly discussed in the North American context with integrated utilities. There, they apply to all loads equally and include the energy cost. The day-ahead proposals typically apply to the context of unbundled electricity systems with wholesale day-ahead markets. Here, they replace only the network tariff component and presumably only apply to flexible loads, which can be inferred from the mechanism in these publications, where the day-ahead network prices are agreed between network operators and aggregators.

Capacity or "Double" Auctions (Fuller et al., 2011; Kok and Widergren, 2016): In this approach, end-users or aggregators of flexible loads submit a bid curve with their willingness to pay for energy. The network operator can aggregate all these bid curves and clear them on the wholesale market, considering the network limits.

If the network limit is not binding, all bids are accepted, and the loads pay the market price plus a standard fee for network access. In case the limit is binding, all loads up to the free capacity in the network are accepted based on their bids, and they pay the price at which this market is cleared (pay-as-cleared), which is then higher than the wholesale price. The network operator collects the price difference as a congestion income.

The network capacity auction can be held a day ahead (Verzijlbergh et al., 2014; Huang et al., 2015) or near real-time. Network capacity auctions integrated with a wholesale energy market in real-time are also known as "transactive energy" approaches (Kok and Widergren, 2016; Abrishambaf et al., 2019). Typically, capacity auctions replace the default network tariff and apply only to flexible loads.

An overview of the different variations and their design variables is given in Table 1. Note that all the proposals described above offer firm network access.

5.2. Local flexibility markets for CM

This category includes all CM proposals based on the DSO's buy-back of network access and end-user load control. Most CM proposals in this category also use auction-based pricing, which justifies the term "market". However, the literature also has some ambiguity around the term "flexibility market". For example, Radecke et al. (2019) review 12 current European proposals. They observe that not every project called a "flexibility market" is a market in the traditional sense where prices are determined based on free bids of participants. Instead, some of the projects they investigated use regulated prices. Furthermore, local CM for the distribution grid is not always the only purpose of schemes labeled "Local Flexibility Market" (LFM) or similar. Ramos et al. (2016) state that an LFM's purpose can be to help resolve localized network constraints and help with non-localized problems such as system balancing or portfolio optimization.

Nevertheless, even though the purpose of the trade and the details of the implementation can vary widely, the basic idea of the "flexibility market" concept is mostly the same: providers of flexibility in the distribution grid (e.g., aggregators of flexible residential loads) are paid to change their power profile. We found several additional design variables specific to this category:

- The choice of reference load relative to which the load profile change is realized. Choices are a baseline (agreed upon by both parties), the current consumption of the trading party (individual end-user or sum of connections managed by an aggregator), and a capacity limit to power usage in kW (see Heinrich et al. 2021, Ding et al. 2013). The power limit may be either fixed contractually or variable, depending on the state of the network.
- Minimum bid size in kW or kWh of flexible load over particular time intervals.
- Matching mechanism of requests and bids for flexibility (see, e.g., Radecke et al. 2019).
- Penalties: Since these proposals are based on end-user control, whether the contracted load reduction occurred should be verified. If the reduction did not occur, there may be penalties specified in the contractual agreements.
- Activation fees: (only for option trades) There may be an additional fee for activating an option.
- Activation lead time for option trades: the interval between the announcement of activation of an option and its activation. For example, the DSO may predict congestion in a specific time interval of the next day and inform the flexibility provider who sold the option that it will be activated at this time. Lead times would generally be one day but could also be a few hours or minutes ahead. The possible values must be defined in the contract agreement between the parties (Ding et al., 2013).

Additional design questions around the implementation and specifics of these markets are investigated in the reviews (Jin et al., 2020; Radecke et al., 2019; Ramos et al., 2016; Schittekatte and Meeus, 2020; Villar et al., 2018; Valarezo et al., 2021; Anaya and Pollitt, 2021; Dronne et al., 2020).

As we can see, many different kinds of proposals for flexibility markets exist in the literature. Most of them have in common that they are based on auction-based price formation, capacity-based commodity (typically as deviation from baseline or current consumption or maximum network capacity) and that they operate in addition to the default network tariff. The most important distinguishing features are reference load, firmness, and trade time frame.

The terminology in the literature can sometimes be confusing: different names are applied to seemingly similar concepts in various proposals and vice versa. In the following, we attempt to give a standardized list of the types of proposed LFM products based on their design variables (see Table 2):

[10] See, e.g., PJM locational marginal pricing fact sheet.

Table 2
Design space variables of LFM products.

	Firmness of network access	Reference load	Time-frame
Flexibility to current cons.	Firm	Current	Near-real-time
Flexibility to baseline	Firm	Baseline	Near-term
Flexibility options	Non-firm	Current, baseline, capacity limitation	Long-term to near-term.
Long term capacity limitation	Firm	Capacity limitation	Long-term

- Real-time flexibility, Flexibility to current consumption (Esmat et al., 2018a), or "PowerCut Urgent" in Ding et al. (2013): reduction of power consumption below current consumption in near-real-time. This approach is typically only a last resort for unexpected congestion problems, as it creates unexpected portfolio imbalances for flexibility providers and would, therefore, likely be an expensive option.
- Flexibility-to-baseline (Esmat et al., 2018a) or "drop-by" in de Heer et al. (2021): Flexibility providers submit a baseline schedule. The DSO gathers these baselines and makes its forecasts to determine whether congestion will happen. When the DSO anticipates congestion, it contracts power reductions relative to the submitted baselines. As this might lead to a re-appearance of congestion at a different time step, some proposals require additionally the specification of a "pay-back" period during which the reduced power consumption is caught up on (Esmat et al., 2018a), or an iteration of adjusted schedules and additional trades until all expected congestion problems are resolved.[11] Because the baseline needs to reflect the actual anticipated power profile of the provider, this variant can only work in the near term, e.g., a day ahead.
- Flexibility option contracts: a contracted power reduction that may be activated during network stress, i.e., the network access is non-firm. There may be an additional activation fee and a penalty for inability to deliver. The contract specifies the time frame and reference load. The time frame can be day-ahead (Esmat et al., 2018a), long-term for a fixed recurring time interval with expected high loads,[12] or a long-term reserve with no specific time ("PowerReserve" in Ding et al. 2013). The reference load can be relative to current consumption at the time of activation (Ding et al., 2013), relative to baseline (Esmat et al., 2018a), fixed capacity limitation (Heinrich et al., 2021) ("PowerMax" in Ding et al. 2013, "drop-to" services in de Heer et al. 2021), or variable capacity limitation ("PowerCap" in Ding et al. (2013)).[13]
- Long-term capacity limitation: a flexibility provider agrees to always stay below a specific contracted network capacity (at all times or within specified times). The Dutch regulator has identified this as one of two market-based flexibility procurement options in the Netherlands.[14]

[11] The Dutch GOPACS platform addresses this issue by matching only orders on existing electricity market platforms if they help resolve a local congestion problem.

[12] For example, between 16:30 and 18:30 on weekdays in a given year, as in the Piclo-Flex platform in the UK (Johnston and Sioshansi, 2020) or the "PowerCut Planned" product in Ding et al. (2013).

[13] This proposal's capacity limitation is based on the available capacity at the congestion point. There is real-time feedback between load at the congested asset and capacity limits for flexibility providers, offering a higher degree of control for the DSO. This product is functionally almost equivalent to the direct load control mechanisms introduced in Section 5.3. The main difference is that the DSO buys the product on the market, whereas the DSO offers it for regulated prices in the proposals in Section 5.3.

[14] Alongside redispatch, see https://www.acm.nl/nl/publicaties/codebesluit-congestiemanagement (in Dutch).

Moreover, the auction format plays a vital role in flexibility markets and can have a strong influence on how efficient the resulting mechanism is. The above product types can be sold with the auction formats listed in Section 4.

5.3. Control-based mechanisms

Direct-load-control (DLC) approaches are those where the DSO can directly control the power consumption of high-power end-user devices, like EVs, or of the maximal power capacity of the connection in times of network congestion. Thus, by definition, these approaches provide non-firm network access. In addition to loads, these mechanisms can also be applied to distributed generation. In addition, their common design variables are typically regulated prices, long-term contracts, and a commodity framed in terms of connection capacity.

Perhaps the most important distinguishing feature is the type of devices to which the scheme is applied. Clean Energy Group (2021) discusses the "Connected Solutions" program in the US, where end-users can enroll their flexible devices and batteries. For a regulated fee, typically a few hundred USD per kW of device capacity, the utility purchases the ability to control these devices directly. As this is in the context of an integrated utility, this ability can help manage network bottlenecks and generation shortages. In the context of unbundled electricity systems, Bundesnetzagentur (2017) also discusses how grid operators may take over a limited control over flexible devices in exchange for reduced grid tariffs but mentions the lack of clear regulations and control technology as obstacles.

There are proposals for a limited grid connection of larger users, where the network operator has the right to curtail or reduce the connection capacity in exchange for a lower grid fee.[15] Bjarghov et al. (2022) discuss a new tariff proposal that would apply to all loads: dynamic capacity subscriptions. These are a variation of the static subscription concept introduced in Section 5.1.1: here, there is no penalty for exceeding the capacity limit in times with no network stress, but when there is congestion, the grid operator can curtail the load at the connection down to the subscribed amount to resolve congestion. Control-based mechanisms have also been applied to distributed generation (Anaya and Pollitt, 2017; Dronne et al., 2020; EUniversal, 2020)

These mechanisms can also vary in whether they are applied based on user consent or by default. EUniversal (2020) gives an overview of use cases, design choices, and the status of current direct control agreements in European countries.

6. Discussion

This section addresses the following questions: How are the different CM mechanisms (Section 5) performing concerning the objectives (Section 3) for the different congestion problem types (Section 2)? What

[15] For example, the Dutch regulator has recently introduced two such agreements: capacity limitation contracts ("Capaciteitsbeperkingscontract) for existing users who opt into a capacity reduction service in exchange for payments, and non-firm connection agreements ("flexibele aansluit-en transportovereenkomst") where mandatory capacity reductions are part of the connection agreement, in exchange for lower fees and sometimes a prioritization of the connection procedure.

Table 3
Summary of performance of CM approaches.

	Suited for	Not suited for	Pros	Cons
Static tariffs	Rough signals for structural congestion	Sporadic congestion	Simple, not discriminating	Not adaptable to sporadic congestion
Dynamic tariffs	All types of congestion problems	Risk-averse or inflexible consumers	Adaptable, no price risk for DSO	Price discrimination, user price risk
Local flexibility markets	Large scale aggregation	Small scale	Theoretically efficient, use of flexibility for other purposes	Gaming of markets, price risk for DSO
Direct load control	All types of congestion problems	Must-run or tight constraint loads	High reliability and decent efficiency	QoS discrimination, curtailment risk

risks may occur? How do the design variables (Section 4) influence performance and risks?

Table 3 gives a summary of our findings. We first introduce the possible risks of CM approaches in Section 6.1 and discuss the influence of design choices on performance in Section 6.2. Finally, we give a detailed qualitative assessment of all the listed CM approaches in the remainder of this section.

6.1. Types and allocation of risks

Every CM approach comes with different kinds of risks that can jeopardize the fulfillment of the objectives:

- Residual risk of network overload: There is the potential that the mechanism does not entirely remove congestion. Static tariffs may be the most likely for this, as they are not adaptable to network conditions. However, it can also occur in other mechanisms: the inflexible load may have been underestimated in day-ahead tariffs, and the tariff set too low. In LFMs, the DSO may not have purchased sufficient flexibility. In DLC methods, there may not be enough load signed up for the load control scheme. Generally, this risk can be reduced as the mechanism moves closer to real-time, making it more adaptable to network conditions. In DLC methods, this risk is also reduced by requiring all high-power flexible loads to sign up by default rather than by consent. In practice, there is always the fallback option of indiscriminate curtailment to avoid overloads leading to damage or safety concerns.
- User network price risk: In CM approaches where the price of network usage is not fixed in advance (i.e., dynamic tariffs), network users have a risk associated with this variability. They may be committed to using the network at this time, e.g., due to external constraints such as industrial schedules, heating, or EV charging requirements, or they may have purchased power on electricity wholesale markets for which they would have to pay additional imbalance fees. The risk is higher the closer the mechanism operates to real-time, as this reduces the chance to plan for alternatives.
- Network operator price risk: In analogy to network user price risk, there are approaches where the network operator carries the price risk. This situation applies to market-based methods where the DSO must buy back network access from users at prices based on user bids. Again, the price risk increases closer to real-time operation, and can also be exacerbated by market failures (Hennig et al., 2022b).
- User curtailment risk: The end-user or aggregator risks being curtailed, which may be due to a feature of the mechanism, as in DLC, or as an emergency in case other CM mechanisms fail. The advantage of the targeted curtailment in DLC approaches is that it can specifically select high-power flexible loads. In contrast, indiscriminate curtailment typically comes with a high customer interruption cost, often represented by an assumed Value of Lost Load.

We visualize the risk allocation of different CM approaches qualitatively in Fig. 3. In addition to the pure risk cases already discussed above, there are also possible mechanisms that can share risks: LFM option types, for example, come with a price risk for the DSO (like other market types) and a curtailment risk for the aggregator in case the option is activated. In this case, network overload is also a residual risk if the network operator does not procure sufficient options or limitation services.

In current practice, there is usually a combination of several mechanisms operating on different time horizons. E.g., LFMs are typically applied in addition to static tariffs. Emergency curtailment can always supplement static tariffs if nothing else is done for CM. Haque et al. (2019) investigate a combining market-based mechanism and "graceful degradation" based on direct control methods. A novel mechanism could also combine near-term dynamic prices with a real-time LFM for emergency buy-back in case the DSO anticipated congestion wrongly. This approach would resemble an "airline" model of slightly overbooking flights.[16] This mechanism leads to sharing the network price risk between the end-user and DSO. However, there are also combinations of mechanisms that might not work well—for example, operating an LFM simultaneously as dynamic tariffs would introduce unnecessary complexity (CEER, 2020).

Fig. 3 can also identify novel CM mechanisms in the "risk space" by identifying a desired risk allocation and constructing a mechanism that leads to this allocation. For example, for a mechanism with both a moderate price risk and curtailment risk for the end-user, this could be in the form of near-term LMP/NCAs for non-firm network access. The DSO may sell near-term network access based on a relatively loose estimate of load. In case congestion does occur, some of the load that purchased non-firm access will be curtailed, and the network price will be returned to them. We have added this option in Fig. 3 in the lower left.

6.2. The influence of design choices

The design variables of congestion management mechanisms impact their performance. We visualize this relation in Fig. 4 and give a few concrete examples in the following:

- The choice of load-controlling party influences who carries the "volume" risk associated with energy delivery: if the DSO controls loads, the end-user or aggregator has a risk of curtailment. If the end-user or aggregator controls loads, the DSO has a risk of network overload, meaning the mechanism may be less reliable.
- DSO position influences who shoulders price risk: in access price-based methods, the end-user may have a price risk; in buy-back-based methods, the DSO has it. Furthermore, buy-back-based approaches are susceptible to misrepresentation of information by private actors: they give an incentive to inflate baselines, maximal capacity or current consumption (based on the specific mechanism), and to employ strategic bidding, which leads to a decrease in efficiency.

[16] This is typically done because some passengers are expected to miss their flight. If there are still too many passengers for the flight (the equivalent of "congestion" in that problem), airlines often auction off the overfilled seats by offering money in increasing steps until the congestion has been removed.

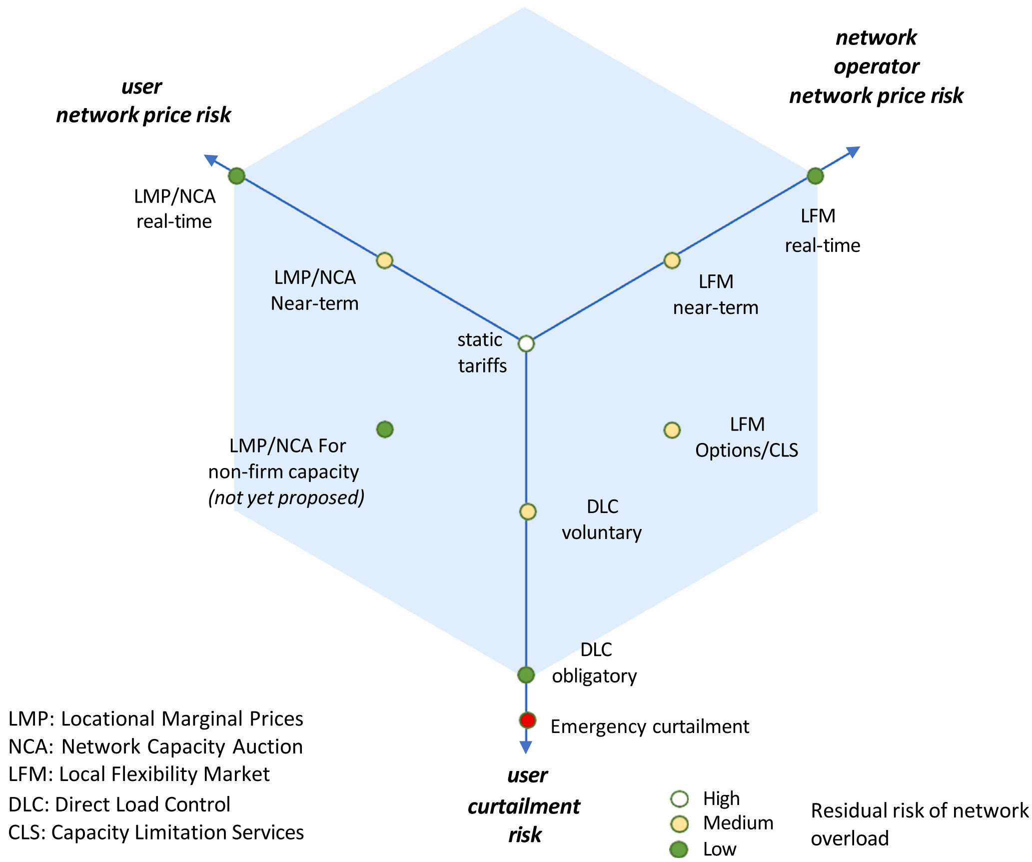

Fig. 3. Risk mapping of CM mechanisms.

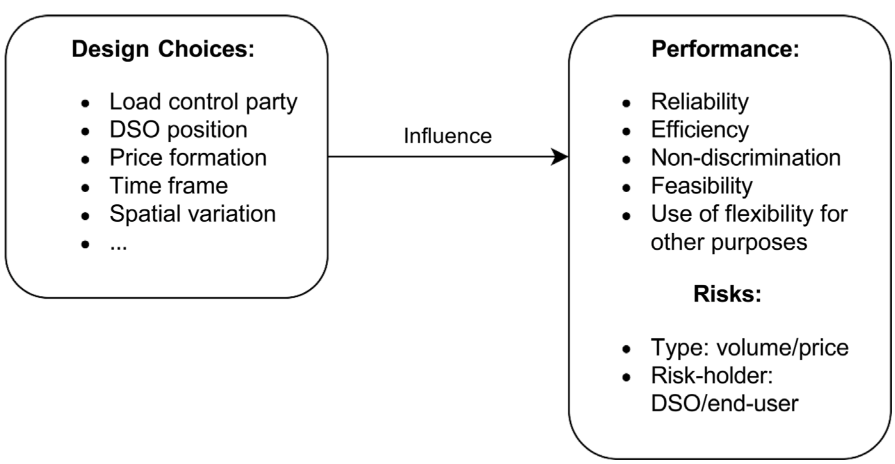

Fig. 4. Design choices influence performance and risks.

- Price formation influences the degree of price risk: with regulated prices, there is no (network) price risk; with auction-based methods, there are varying degrees of risk, depending on the time frame and competitiveness of the market. Auction-based methods may increase efficiency in well-functioning competitive markets or decrease it in case of market failures. Further, they have a higher degree of complexity.
- Varying the time frame from static through near-term to real-time has multiple consequences: price risk increases, reliability increases, complexity increases, the usability of flexibility for other purposes decreases, and efficiency generally increases, though it may be compromised in near real-time as this only allows a shifting of loads to later times, not earlier ones.
- Spatial variation: Each of the CM mechanisms listed could be applied at different spatial granularity, tailored to the congestion situation in the network. Higher granularity could increase the reliability and overall efficiency of the mechanism (as MIT Energy Initiative and IIT Comillas, 2016 shows for LMP), as congestion areas can be targeted deliberately. However, it comes at the cost of introducing discrimination: users in congested areas pay more than those in non-congested areas.[17] This result may be

[17] This is different with flexibility markets, where users in congested areas may even benefit more from congestion by charging inflated prices.

considered unfair, as it depends on the state of the network, on which users have no influence.[18]

6.3. Static tariffs

Static tariffs give rough incentives to reduce congestion but are not adaptable to network conditions. Thus, there is no guarantee that they will resolve it entirely. For example, the peak times in ToU tariffs can be tailored to expected structural congestion times but are not adaptable to deal with sporadic congestion. Capacity-based tariffs give further incentives to limit peaks, which can also be differentiated by time. However, a static price signal sometimes disincentivizes network access when there is spare capacity, limiting efficiency as the network is not used to the extent that would be economically desirable. The positive aspects are that static tariffs are simple and not discriminatory.

Note that we only considered the performance of tariffs concerning congestion management here. As this is not the primary purpose of network tariffs, other considerations are relevant when evaluating their performance (Reneses and Ortega, 2014; Hennig et al., 2022a).

6.4. Dynamic tariffs

The peak-based approaches CPP and NCPC can increase reliability, especially for expected structural peak events, e.g., during heat waves or cold spells (CEER, 2020). As they specifically target these times and do not needlessly restrict network access at other times, this would also increase efficiency. On the other hand, since they typically apply to all loads equally, they may not be a good solution for situations with many sporadic congestion events driven by flexible loads.

More dynamic proposals like DLMP and NCA can react better to network conditions and thus may potentially improve reliability and efficiency even further. On the other hand, they come with their own set of problems. Firstly, their effectiveness increases with spatial granularity (MIT Energy Initiative and IIT Comillas, 2016), allowing them to be tailored more to the specific congestion problem. However, this also introduces price discrimination. It could be interesting to investigate tariffs with the same price on average but higher variations in congested areas to yield a stronger control signal. Secondly, they require sophisticated communication interfaces to transmit the price signal, which means they have a higher implementation burden. Thirdly, vulnerable consumers may be unable to react to them and be hit with unexpectedly high charges.[19]

Network Capacity Auctions can resolve the network price-risk problem by simultaneously clearing the energy market, as in the transactive energy proposal by Kok and Widergren (2016). Theoretically, this setup may have the potential for the highest reliability and efficiency. However, this comes at a high system implementation burden where every device must communicate its bid function continually.

An alternative could be a dynamic tariff where it is not the price that varies in response to network conditions but the available network capacity of users, i.e., a tariff with non-firm access conditions. This approach would remove the price discrimination problem for network access and protect vulnerable customers against price spikes. We will investigate this type of tariff in more depth in future work.

An additional important consideration with dynamic prices is what happens with the generated revenue. As their prime purpose is not cost recovery but congestion avoidance, they might not be counted towards the normal operating income of the DSO. Otherwise, this may create a perverse incentive for the DSO not to upgrade the network to collect more congestion rent. Therefore, these revenues should be collected as a separate budget item and could, e.g., be used for network upgrades.

6.5. Local flexibility markets

LFMs for CM have been proposed to deal with structural congestion problems in extended period option markets (Ding et al., 2013; Johnston and Sioshansi, 2020) and sporadic congestion events (Ding et al., 2013; Esmat et al., 2018a). Theoretically, the advantage of a market is that it could remove congestion in an economically efficient way by paying flexibility providers at their marginal cost of shifting loads. This approach would also remove the price discrimination in dynamic price schemes. However, the theoretical optimum could only be reached if flexibility providers submit truthful information about their available flexibility and costs. Unfortunately, the basic premise of these kinds of markets, paying providers for adjustment of their energy consumption, is prone to manipulation by withholding private information and misrepresenting costs and flexibility (Crampes and Léautier, 2015). This situation might even lead to a form of "reverse" price discrimination: flexibility providers in congested areas may be able to collect greater rents on congestion by behaving strategically. Furthermore, this discrimination is also socially regressive in terms of wealth. As Ribó-Pérez et al. (2021) showed, the wealthier members of the population can invest in flexible devices and obtain rents from these kinds of markets. In the following, we discuss a few potential problems that can occur.

The auction format and strategic bidding. As mentioned before, the choice of auction format significantly impacts the outcomes: In a pay-as-bid market, congestion could theoretically be removed at the lowest cost if all participants bid truthfully. However, there are well-known problems in pay-as-bid markets (Kahn et al., 2001; Heinrich et al., 2021; Anaya and Pollitt, 2021), as it incentivizes participants to bid higher than their actual costs.

In uniform (pay-as-cleared) price markets, flexibility is traded at the marginal supplier's price. All bidders below this price collect additional rents equal to the difference between their bids and the clearing price, meaning congestion is no longer removed at the lowest possible cost for the DSO. The incentives to over-represent costs are not as strong as in pay-as-bid because bids above the clearing price would not be accepted. In contrast, below the clearing price, it does not matter whether the provider bids at its marginal cost or not, as it will always be accepted. However, flexibility providers that control many flexible loads may be able to manipulate the clearing price by bidding their whole fleet above marginal costs. In highly localized markets, an aggregator might easily acquire market power at a single LV feeder by controlling only a few dozen EVs. A further illustration of this problem can be found in Hennig et al. (2022b).

Heinrich et al. (2021) propose a modified VCG auction as an alternative that pays each flexibility provider according to the benefit they bring to the system. However, this would still be more than the marginal cost of shifting loads, which implies that flexibility providers still collect rents on congestion. Additionally, it is still possible for individual actors or cartels of actors with a large share of flexible loads to inflate the price artificially.

Strategic bidding may be mitigated by having a large pool of potential providers, so acquiring market power becomes more difficult. Thus, LFMs might be a better solution for larger-scale congestion problems, such as MV substations, rather than individual LV feeders.

Manipulation of baselines and real-time consumption. In addition to the problem of strategically bidding above marginal costs, there is another problem in LFMs: the strategic adjustment of consumption, either in supposed baselines or in real-time, to collect higher rents from LFM payments. These strategic adjustments typically even worsen the original congestion problem. For profit-maximizing actors in the market, it is rational to adjust their consumption so that they consume *more* when there is a congestion problem. In this way, they also get paid more.

Ziras et al. (2021) have comprehensively discussed this problem concerning baselines and showed that it exists irrespective of the

[18] See also Hennig et al. (2022a), National Grid ESO (2022) for similar discussions on network tariffs and nodal pricing respectively.

[19] This problem was demonstrated in Texas, where marginal pricing is already applied to many households. When, in February 2021, a major winter storm caused very high electricity prices, some consumers faced extremely high bills as they were unaware of the costs (Gruber et al., 2022).

method used to construct baselines. A possible exception to this is large industrial consumers where the baselines pertain to specific processes and can be easily verified.

In real-time LFMs, a similar problem exists when market participants realize that there is a congestion problem and that they can benefit from artificially increasing their load to be paid to reduce it.[20] This problem is similar to the problem of "inc/dec" gaming in redispatch markets identified by Hirth et al. (2019).

In capacity-limitation LFMs like (Heinrich et al., 2021), the payments increase in line with the maximum potential power consumption of flexible loads, as the limitations have to be computed relative to this theoretical maximum power consumption. Thus, this practice incentivizes them to over-represent this number, akin to the issue of inflated baselines.

There are also specific problems in option-type LFMs. Proposals based on long-term contracts for load reductions at particular times can lead to a commitment problem: the provider is committed to being able to supply the load reduction given in the agreement. Thus, it has to schedule loads at these times. Otherwise, it would not be able to fulfill the contract, even when it would be disadvantageous to do this based on wholesale prices and network conditions, as otherwise, the aggregator would be faced with a penalty. Eliminating the penalty is also not an option, as it would allow the aggregator to sell an indefinite amount of products it does not have to supply.

Feasibility. Setting up an LFM requires sophisticated communication and control infrastructure, which might be why there are only small pilots and demonstration projects (Jin et al., 2020). As Dronne et al. (2020) observe, the size and capabilities of DSOs can differ widely, and for smaller DSOs, setting up the required technology can pose a significant resource challenge. Even for larger DSOs, it is questionable whether setting up an LFM for every potentially congested LV feeder is possible, further suggesting that LFMs might be more applicable to larger-scale congestion problems, not to highly localized congestion.

Use of flexibility for other purposes. Perhaps the most significant advantage of LFMs is that they are not limited to resolving congestion problems; flexibility may also be offered for other purposes. Coninx et al. (2018) investigate a setup where it is offered to multiple potential buyers: DSOs, TSOs, and BRPs. Ramos et al. (2016) discuss how flexibility products could be traded on a larger, location-agnostic market and localized sub-markets. They stress that for flexible products offered on the larger market, it is essential that they do not violate any localized constraints. Hence, the market mechanism needs to take this into account. An example is the Dutch platform GOPACS,[21] where the LFM operates in addition to the existing intraday market with a location tag.

6.6. Direct load control

DLC schemes tend to have high reliability, as the DSO controls the load and can steer as many devices as necessary to resolve congestion. This observation holds for both small and large-scale problems and structural and sporadic congestion. A potential reliability problem may occur in consent-based schemes when not enough loads have signed up for the program. Default sign-up-based schemes are more reliable as they give greater control to the DSO but may also be seen as unfavorable and heavy-handed by consumers.

Since prices for the scheme are set by the DSO long-term, they may not remove congestion strictly at the marginal cost of shifting flexible loads. On the other hand, they are also not likely to considerably overpay flexibility providers, as may happen in LFMs that are susceptible to strategic behavior by flexibility providers. Moreover, the DSO can adjust prices over several billing periods to move closer to an efficient solution.

Discrimination comes in the form of Quality-of-Service: A flexible provider in a congested area would be curtailed more often than a provider in an area with little congestion. Potential remedies to this could be to adjust prices based on the anticipated number of congestion events, to give ex-post rebates based on the number of events, or to set fixed acceptable limits on the maximal number and duration of curtailments, as done in Clean Energy Group (2021). This solution might be fairer than dynamic prices because, with those, users with lower willingness-to-pay would be priced out, while others would be charged high prices.

Regarding feasibility, DLC schemes are relatively straightforward: they only require the installation of a load-limiting device that the DSO can control. It may also require the installation of a separate meter for flexible loads. Considering the slow roll-out of smart meters in many European countries, this could still be seen as a significant obstacle. However, it would only affect consumers who own EVs, electric heat pumps, or PV cells, so the required installations could be part of the permitting process for these devices.

One potential problem in these schemes is the interference of the load control mechanism with the portfolio of Balance Responsible Parties (BRPs) in unbundled electricity systems. If the congestion removal requires a significant amount of curtailment of flexible devices, it may create a problem for the energy provider of these devices in fulfilling their energy program. This challenge may explain why these schemes seem to have only been applied by North American utilities that are vertically integrated and control both energy supply and distribution. In the European context with unbundled energy systems, it is necessary to have close coordination between the operation of the CM mechanism and the energy provider.

7. Conclusion

Electric distribution networks have various congestion problems and potential mechanisms to resolve them. The main categories of CM mechanisms are static and dynamic access prices, Local Flexibility Markets, and direct control methods. Some of these mechanisms are variations of network tariffs, while others are specialized mechanisms on top of a default tariff.

The design choices of these mechanisms influence their performance and risks. For example, market participants' potential for undesirable strategic behavior should be carefully considered. It may turn out that this may point towards abandoning market-based approaches in favor of methods with lower price risk for the DSO. In general, mechanisms should be fitted to the problem they are intended to solve by carefully considering all possible design choices.

Academic studies and proposals of new CM solutions should include a precise problem analysis as a starting point. What kind of congestion are they attempting to solve regarding localization, timing, predictability, and network limitation? There is no one-size-fits-all, so it is essential to know the specifics of the problem to judge the merits of the proposed solution.

Network operators should collect data on existing and anticipated congestion problems: at what local scale do they appear? Is the timing at regular hours, or does it fluctuate due to external factors like weather and wholesale prices? Are they related to thermal overloading or power quality due to load or feed-in? This information and a clear regulatory framework could help significantly to find applicable solutions.

[20] A particularly striking real-world example has been given by the case of a baseball stadium in Baltimore and a demand response program by the regional grid operator PJM: When PJM sent out a declaration of an emergency event as part of the demand response program, the baseball stadium switched *on* the stadium lights, even though there were no games or practice scheduled, to collect payment for reducing the demand by switching off the lights again.

[21] GOPACS

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.

Data availability

No data was used for the research described in the article.

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