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Council of European  
Energy Regulators



**REPORT**

# **NRAs' Approach to DSO Flexibility Procurement, Justifications for Derogations from Article 32**

**07.11.2025**



# NRAs' Approach to DSO Flexibility Procurement, Justifications for Derogations from Article 32

Distribution System Working Group

## INFORMATION PAGE

### Abstract

This paper provides an overview of how National Regulatory Authorities (NRAs) across EU Member States approach the procurement of flexibility services by Distribution System Operators (DSOs). Based on a CEER survey of 21 NRAs, it examines the national processes for derogations from Article 32 of the Electricity Directive, which mandates market-based procurement unless specific conditions are met.

The paper conceptualizes an iterative process that links strategic planning and flexibility quantification tools—namely Distribution Network Development Plans (DNDPs) and the new Flexibility Needs Assessments (FNAs)—with the possible derogation process and the operational action (flexibility procurement) of the DSO. The paper identifies key drivers, prerequisites and barriers for local flexibility markets and analyzes the status of national derogation processes, finding that most surveyed countries have not yet defined a formal procedure.

Furthermore, the paper explores how network flexibility could be valued in different cases, such as by calculating avoided or postponed grid reinforcement costs. It also examines the integration of flexibility costs into tariff methodologies, underscoring the importance of technology neutral regulatory frameworks. The findings and recommendations aim to enhance regulatory practices, improve transparency, and support the development of local flexibility markets that serve local network needs.

### Target audience

European Commission, NRAs, energy suppliers, DSOs, other network operators, traders, electricity customers, electricity industry, consumer representative groups, Member States, academics and other interested parties.

### Keywords

Flexibility, flexibility procurement, distribution networks, electricity, regulation, market-based flexibility, non-market-based flexibility, derogation process.

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## Related documents

### CEER Documents

- ACER-CEER (2025) Guidance on Electricity Distribution Planning
- CEER (2025) Paper on Incentives in Regulatory Frameworks with a Focus on OPEX/CAPEX Neutrality.
- CEER (2020) Paper on Alternative Connection Agreements.
- CEER (2019) Paper on DSO Procedures of Procurement of Flexibility.

### External Documents

- [ACER \(2025\) Type and format of data and the methodology for TSOs' and DSOs' flexibility needs analysis \(FNAM\).](#)
- ACER (2023) [Barriers to demand response \(2023\).](#)
- ACER (2025) Unlocking flexibility: No-regret actions to remove barriers to demand response - 2025 Monitoring Report.
- [JRC \(2025\) DSO Observatory 2024.](#)
- [JRC \(2022\) Local electricity flexibility markets in Europe.](#)
- [Michaelis et al. \(2025\) Designing local flexibility markets: A toolbox for policymakers and market operators, Energy, Volume 329](#)
- [Rebenaque et al \(2023\) Success of local flexibility market implementation: A review of current projects, Utilities Policy, Volume 80](#)
- [SmartEn \(2024\) Implementing EU laws: A guide to activate demand-side flexibility in the EU 27 Member States.](#)

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## EXECUTIVE SUMMARY

### Background

The Electricity Directive (EU 2019/944) encourages DSOs to procure flexibility services through market-based mechanisms. However, NRAs may grant derogations under Article 32 if market-based procurement is economically inefficient, causes market distortions, or increases congestion. With the upcoming Network Code on Demand Response and with the Electricity Market Design reforms, understanding national approaches to flexibility procurement and the possible derogation from Article 32 is valuable.

### Objectives of the document

This paper aims to:

1. Provide NRAs with an overview of national practices in DSO flexibility procurement and derogation processes concerning Electricity Directive's Article 32.
2. Examine how network flexibility is valued within regulatory frameworks, especially in non-market-based contexts.
3. Offer recommendations to support the development of local flexibility markets.

### Conclusions

Even where it is deemed the most efficient solution, the development of market-based flexibility procurement by distribution system operators is inhibited by several information and technology related barriers. The regulatory framework in place can also impact whether DSOs develop their grids in a technology neutral way and take advantage of network flexibility when it is deemed appropriate.

The various planning and procurement processes relating to DSO flexibility (like network development plans, flexibility needs assessment and possible derogations under Article 13 Regulation or Article 32 Directive) can be thought of as interconnected steps. While EU rules prioritize market-based solutions, they allow for derogations (exemptions). Market-based flexibility procurement is not a goal in itself, but a starting point for the investigation to identify the most efficient solution for the DSOs to operate and develop their network.

Less than half of the surveyed countries have a formal process in place for derogations under Article 32, and there is no clear consensus on the specific indicators to assess economic inefficiency, market distortion, or increased congestion. So far, no derogation request has been denied. Of those, 3 MSs have granted derogations for all the DSOs, the rest are still in the process. No country has yet denied a derogation application. Around 50% of the respondents grant the derogation for a period between 1-2 years and in around 50% of the cases, the DSO does propose an action towards reaching market-based procurement.

There is no standard method for valuing flexibility. Current approaches include benchmarking it against the cost of grid upgrades or calculating the costs of regulation.

# 1 Introduction and purpose of the paper

## 1.1 Background

With this paper, CEER aims to have an overview of how flexibility procurement of distribution system operators (DSOs) is approached in different member states (MSs). As the Directive (EU) 2019/944 on the internal market for electricity ('Electricity Directive') sets forth in its article 32, MSs shall provide incentives to distribution system operators to procure flexibility services (including congestion management) and 'distribution system operators shall procure such services in accordance with transparent, non-discriminatory and market-based procedures unless the regulatory authorities have established that the procurement of such services is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion.' That is, DSOs should be encouraged to consider flexibility alternatives compared to network build-out and to do that – by default – in a market-based manner. From the aforementioned Art. 32, only the NRA can grant derogations based on the three above listed reasons (economic inefficiency, market distortion, higher congestion). Article 13 of Regulation (EU) 2019/943 on the internal market for electricity ('Electricity Regulation') mirrors a similar spirit stating in its paragraph 2 that 'resources that are redispatched shall be selected (...) using market-based mechanisms' and paragraph 3 laying down that 'non-market-based redispatching of generation, energy storage and demand response may only be used' under certain predefined circumstances. A key difference between the two provisions is that while the subject of the directly applicable regulation's Article 13 is redispatch done either by the TSO or the DSO, but the process for determining a derogation according to paragraph 3 is not further defined, the subject of Article 32 of the Directive are DSO flexibility services in general (redispatch included) and it's clearly stated that the NRA is the entity who may grant the derogation. However, the relationship between the two set of rules is not further clarified. This paper examines the national application approaches to the implementation of Article 32 of the Directive, as it covers DSO flexibility services in general, and NRAs are competent in granting the derogation. Article 13 of the Regulation is only covered to the extent where the topic and/or survey answers imply the relevance or necessity thereof.

## 1.2 Purpose, scope and approach

Now that the draft network code on demand response is expected to strengthen this market-based approach for the procurement of local flexibility, and it aims at prescribing more detailed rules for the derogation process, it is vital for NRAs to have a good grasp of current national approaches to distribution-level flexibility procurement (or local flexibility markets) and the derogation therefrom. The main purpose of this document is to grant NRAs this overview of national practices based on a member survey.

The second aim of the document – also mirrored in the survey described below – was to have an overview of approaches for the valuation of flexibility in the context of regulatory frameworks for DSOs (as reflected in tariff methodologies) and discover, whether jurisdictions with more advanced local flexibility approaches have certain common characteristics.

Thus, for this paper CEER conducted a “Survey on NRAs’ approach to DSO flexibility procurement”. The survey was conducted in the fall of 2024, and it received 21 answers from NRAs. The survey included six main topics to gather necessary information. These topics were:

1. National Process for derogation under Article 32 of the Electricity Directive
2. Recognition of flexibility costs in DSO tariff and remuneration methodology (including incentives)
3. Valuation of non-market-based flexibility specifically
4. Assessment of flexibility options in network development plans
5. DSO capabilities and barriers to identify network needs
6. Procurement of market-based and non-market-based flexibility

## 2 Local flexibility markets and non-market-based flexibility procurement

### 2.1 What is flexibility?

Flexibility has found its way into both public and professional focus. However, some clarification might still be needed to properly introduce the aim of the paper. As per the new definition introduced by the EMD (see section 2.3), under section (79) of Article of the Electricity Regulation, (network or system) flexibility – the type of flexibility that is relevant for this paper – ‘means the ability of an electricity system to adjust to the variability of generation and consumption patterns and to grid availability, across relevant market timeframes’. ACER’s flexibility needs assessment methodology (linked to the national flexibility needs assessments under Article 19e of the Electricity Regulation) provides further clarification by differentiating between system and network flexibility needs<sup>1</sup>.

In the context of this paper, only (network) flexibility services that are relevant for the DSO are covered and usually, these are collectively called ‘local flexibility services’<sup>2</sup> (procured by the DSO in contrast to balancing, which is a nationwide or even European-wide balancing-zone-wide market operated by the TSO). This also entails that balancing and TSO-level redispatch are generally out of scope for this paper, but it should be kept in mind that the TSO-level redispatch can have significant impact on the DSO-level.

When deciding on the national/regulatory approach towards distributed flexibility, the Member State and/or the NRA should always consider the costs and benefits of a given solution for the whole of the system. Uncoordinated use of flexibility by system operators can entail adverse

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<sup>1</sup> [https://www.acer.europa.eu/sites/default/files/documents/Individual%20Decisions\\_annex/ACER-Decision-05-2025-FNAM-Annex-I.pdf](https://www.acer.europa.eu/sites/default/files/documents/Individual%20Decisions_annex/ACER-Decision-05-2025-FNAM-Annex-I.pdf) Article 2 point 2 v and hh: ‘network flexibility needs means the flexibility needed to adjust for grid availability, by means of preventing or solving congestion or voltage issues, across relevant timeframe’ and ‘system flexibility needs’ means the flexibility needed by the electricity system to adjust to the variability of generation and consumption patterns, across relevant market timeframe’.

<sup>2</sup> In ACER’s Recommendation on the Demand Response Network Code (‘DRNC’), (19) of the Preamble states that ‘Local services can be used to alleviate or postpone the need to reinforce or expand the grid in order to solve congestion or voltage issues, or to provide a solution until a decided grid reinforcement project is completed, enabling a more efficient use of the system as well as the connection of additional generation and/or demand capacity.’ In Article 2 (6) of the draft DRNC, ‘local service’ means energy or capacity provided by a service provider to a TSO or DSO to solve intra-zonal physical congestion or voltage issues they have identified in their systems’.

effects at the overall system balancing level (local vs. system needs). Conversely, market signals at the system level can also exacerbate congestion issues at a local level (market signals vs. physical network constraints). This is the reason for the Directive to mention possible distortive effects of market-based procurement of local services. Therefore data-sharing and coordination across DSOs, TSOs and market platforms is critical in ensuring that electricity system participants at different voltage levels are aligned. Furthermore, solutions that are seemingly free for the procuring DSO (such as concluding/activating a flexible connection agreement) might have hidden or very explicit impacts for other actors in terms for e.g. costs, which then have system level implications for a given design. Hence, the coordination of the various processes using different instruments (grid connection and, e.g., certain types of FCAs<sup>3</sup> or redispatch measures) is crucial. The NRA or (if it belongs in its competence) the Member State should ensure that a given solution does give incentives for the desired and disincentives for the undesired (market and network) outcomes (including the prevention of market abuse and distortive behaviour such as e.g. increase-decrease-gaming).

## 2.2 How can the DSO access flexibility?

Beyond the DSO's technical solutions using their own assets, local flexibility can take many forms, most prominently flexibility services<sup>4</sup> such as congestion management (for example redispatch, which also includes curtailment) and voltage control<sup>5</sup> all of which can be procured either on a market-based manner (i) or through a rules-based approach (ii). As previous CEER work<sup>6</sup> identified, beyond these two options, there are network tariffs (iii) and connection agreements<sup>7</sup> (iv) by way of which DSOs can acquire network flexibility. These tools grant access to different forms of flexibility with different levels of certainty and control and the choice of measures is the result of several factors. One of them is the regulatory framework, defining OPEX/CAPEX treatment, efficiency requirements and potential incentives on R&D. Some of these tools can naturally coexist (see also NRA expectations on a purely market-based flexibility procurement in Section 3.2.2), most prominently tariffs, with market-based procurement, but market-based and rules-based procurement for the same group of grid users are mutually exclusive. The tools can also interact with each other: flexible connection agreements may grant the DSO access to flexibility without any compensations, but may be limiting the grid users' options to offer market-based services. Tariffs, depending on their design may increase or decrease the need for market-based flexibility and congestion management.

Based on JRC's most recent DSO Observatory's (2024) findings, most (48%) of the DSOs participating in their study rely on flexibility resources through market-based approaches (tenders/markets), followed by interruptible load tariffs<sup>8</sup> and flexible connection agreements.

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<sup>3</sup> Throughout the document, the attention is drawn mostly to the possible interaction between congestion management and FCAs that are designed to have the same effect (such as „fully dynamic FCAs“).

<sup>4</sup> JRC DSO Observatory: DSOs in their study use flexibility mainly for congestion management (90%) and voltage control alone or in combination with congestion management (32%). Grid islanding & restoration were marked by 10% of the DSOs and 6% reported other uses. (p 59).

<sup>5</sup> It should be noted that the regulatory approach to voltage control seems to have shifted somewhat, since while the Directive addresses non-frequency ancillary services separately from DSO flexibility services [Article 31 (7)], the draft DRNC groups congestion management and voltage control together under the umbrella of local services.

<sup>6</sup> [CEER Paper on DSO Procedures of Procurement of Flexibility](#)

<sup>7</sup> See [CEER Paper on Alternative Connection Agreements](#)

<sup>8</sup> JRC: “interruptible tariffs grant a network customer a reduced tariff in return for allowing the DSO to interrupt or reduce the power consumption”

Figure 51. Type of mechanisms for DSO access to flexibility

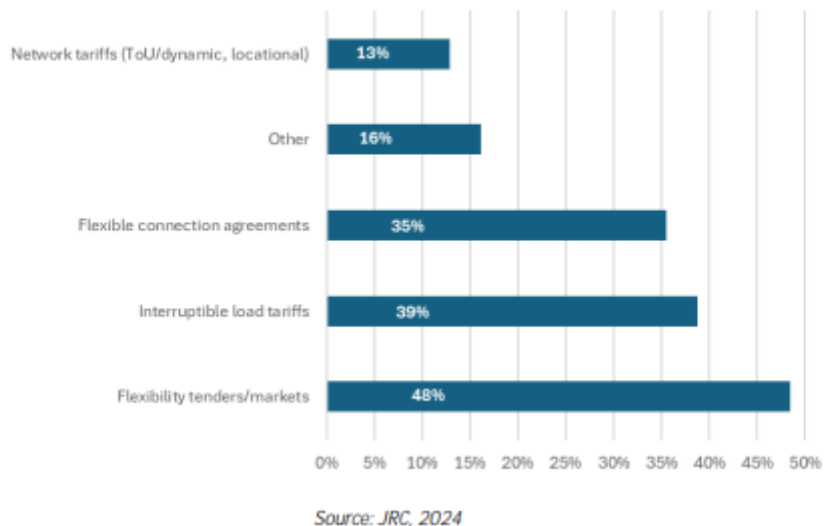


Figure 1 Type of mechanisms for DSO access to flexibility from JRC (2024)

According to CEER’s Paper on Alternative Connection Agreements, ‘NRAs need to carefully assess the interaction between alternative connection agreements and other, especially market-based, mechanisms for DSOs to access flexibility when considering their implementation. (...) If DSOs are already able to access flexibility of system users via market-based mechanisms, alternative connection agreements might negatively affect the market for flexibility by reducing liquidity and aggravating or creating market distortions. Although the impact of either entering alternative connection agreements or market-based procurement of flexibility on the network is similar, the distribution of costs and benefits is very much different and could lead to a loss in social welfare and sub-optimal network investments as a result.’ There is a similar concern relating to alternative connection agreements and developing flexibility markets<sup>9</sup>.

### 2.3 Relevant legal framework

The core provision discussed in the paper, as mentioned in the Introduction, is **article 32 of the Electricity Directive and not Article 13 of the Electricity Regulation**, laying down an obligation to provide incentives for the DSOs to consider flexibility procurement as a non-wire alternative unless certain circumstances give reason for derogation. The most important development in this context is, on one hand, the adoption of the so-called Electricity Market Design (EMD) package, which comprises amendments to the Electricity Regulation and Directive and the Renewable Energy Directive and the ACER Regulation aiming primarily at mitigating the effects of the energy price crisis in 2021-2022. Among the amendments, several

<sup>9</sup> This coordination effort can be reduced by separating flexible connection agreements from redispatch and designing them as a preceding mechanism: In this design, the FCA specifications apply regardless of the current network load, which means that the DSO can take this into account when planning redispatch.

touch upon some aspect of flexibility, the most prominent being the new **Article 19e of the Electricity Regulation** on the assessment of flexibility needs (FNA<sup>10</sup>). This will be an obligatory national report due July 2026 'on the estimated flexibility needs for a period of at least the next 5 to 10 years that shall evaluate different types of flexibility needs, at least on a seasonal, daily and hourly basis, to integrate electricity generated from renewable sources in the electricity system, inter alia, different assumptions in respect to electricity market prices, generation and demand and consider the potential of non-fossil flexibility resources such as demand response and energy storage, including aggregation and interconnection, to fulfil the flexibility needs, **both at transmission and distribution levels**'.

On 11 March 2025, ACER published its **Recommendation on the Network Code on Demand Response**<sup>11</sup> that goes into detail on local flexibility markets in its Title IV, 'Market based procurement of local services', also specifying further rules on the derogation from market-based procurement (Article 30) and adding specific provisions for distribution network development plans (Articles 43-44).

It should also be noted that according to Art. 33 and Art. 36 of the Electricity Directive, by default, DSOs shall not own, develop, manage or operate neither energy storage facilities nor recharging points for electric vehicles, except when they are explicitly granted such derogation.

## 2.4 Local flexibility markets: drivers, prerequisites, barriers, key success factors for implementation

### 2.4.1 Drivers or why (or when) do we need local flexibility markets?

What do DSOs (or what could DSOs) typically use distribution level flexibility for? Based on a survey that was initiated by one of the regulators within CEER, the answers include the following: 'efficient use of the electricity grid', 'congestion management (for investment deferral)', 'increase hosting capacity', 'flexible connection agreements to connect more consumers sooner', 'to answer flexibility needs in a particular area', 'operating support, maintenance and in the event of a threat to the safe and reliable operation of the system', 'to reach emission and renewable targets'. It should be noted that the question referred to distribution level flexibility (not market-based flexibility or flexibility markets for example) generally, and this is also reflected in the broad range of answers, implying that flexibility may be used for various purposes. JRC (2022) offers a more structured categorisation of these services, finding that DSOs procured the following types of flexibility: "congestion management, voltage control, reliability enhancement, network deferral". In the draft DRNC, local services only include 'energy or capacity provided by a service provider to a TSO or DSO to solve **intra-zonal physical congestion or voltage issues** they have identified in their systems', meaning that the draft DRNC does not cover all use cases of distribution level flexibility.

JRC (2022) also identified three main drivers behind the need to develop local flexibility markets:

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<sup>10</sup> FNA for flexibility needs assessment and [FNAM for the methodology \(published by ACER\) on the 'Type and format of data and the methodology for TSOs' and DSOs' flexibility needs analysis'](#).

<sup>11</sup> This means that the network code is a draft version and will foreseeable be subject to changes during the final part of the legislative procedure before the European Commission. The Recommendation may be found here: <https://acer.europa.eu/news/new-network-code-demand-response-will-further-advance-energy-transition>

- '1. short- and long-term 'freeing' of distribution capacity for accommodating the electrification process (e.g. in the two Nordic projects)<sup>12</sup>;
2. unlocking the flexibility potential in the distribution system for congestion management services mainly in the transmission system (e.g. GOPACS);
3. the management of the distribution grid under increased penetration of distributed vRES facilities (e.g. the enera project and the ENEDIS tenders).'

However, in the same publication, JRC (2022) found that '**management of the distribution network under increased distributed vRES penetration is the least pressing driver** for the development of local flexibility markets. Under such conditions, the **utilisation of local flexibility focuses instead on economic efficiency** rather than on maintaining operational security: the network operators usually have other options for the latter, such as flexible connections'.

In some jurisdictions and on some occasions, DSOs seem to be reluctant to procure flexibility from grid users and tend to rely on their own assets<sup>13</sup> technical capabilities or other grid enhancing technologies to acquire flexibility, even when tightness of connection capacities is otherwise apparent.

It seems that in most cases, a driver has to be very imminent or pressing for a DSO to start considering market-based flexibility procurement to increase its efficiency or address a challenge. Potential reasons for this might include OPEX/CAPEX bias and the difficulty of setting up a whole new activity within the organisation<sup>14</sup>.

However, DSOs have to operate in a cost-effective manner; they need to apply the solution that tackles a given problem in the most efficient manner (also considering implementation costs), be that tariffs, flexible connection agreements, flexibility procurement (either market- or rules-based) or network development. Using market-based flexibility procurement by DSOs is not an aim in itself, rather a starting point (prescribed by both the Electricity Regulation and Directive) for the investigation on how a DSO can fulfil its obligation to effectively operate and develop its network to satisfy the customers' and generators' needs.

## 2.4.2 Prerequisites and success factors of market-based flexibility procurement

At the moment, when a DSO concludes that it needs flexibility, it has several options to choose from, only one of which can be market-based procurement (although the one preferred by EU legislation, over rules-based and other types of non-market-based procurement). What prerequisites need to be met (or are realistic to be met in due time) for flexibility markets to be considered by DSO governance or to break out of the pilot project status and reach advanced maturity?

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<sup>12</sup> Where the lead time of a connection request is not a quality of supply criterion, 'congestion' does not necessarily appear as network congestion but as a connection queue bottleneck. Still, if there is no incentive linked to connection lead times, the timing of the occurrence of a flexibility need might be pushed further away in time.

<sup>13</sup> Although in general, DSOs are prohibited to own, develop, use or operate storage facilities (pursuant to Article 36 of the Electricity Directive), there are two notable exceptions, one for the fully integrated network components (assets included in the RAB of the DSO) and the other for when the DSO issues an unsuccessful tender for services it needs to fulfil its legal obligations.

<sup>14</sup> Market-based flexibility procurement usually requires new procedures, new communication and cooperation structures, new responsibilities, building new expertise and experience, maybe even restructuring within the DSO's organisation.

Not all flexibility markets are all alike: there are some, that are very simple tenders published on the DSO's webpage (so there's no dedicated platform or user interface) in contrast to continuous markets; there are long-term and short-term tenders and products with high or low granularity, too; there are markets with high levels of integration with other markets (balancing or wholesale) and there are those that aren't, and there are many services and many attributes to a single product, too, that might vary from DSO to DSO, or even from one flexibility need to the other.

The first thing needed is that the DSO can identify the flexibility need, then translate the potential solution(s) into a product that might be offered by potential flexibility service providers, that is: (i) visibility of the problem (that is, grid observability and ability to identify the problem), (ii) appropriate product design for the solution (efficiency, fitness for purpose), (iii) sufficient number of available service providers, and finally (iv) the resulting market is not susceptible of or can be protected against gaming. Furthermore, the third prerequisite unfortunately comprises several painfully hard to achieve subsets of requirements, too: assets deployed technically able to perform the task (standardisation and technology neutral product parametering might help), clear and easy prequalification, controllability and some level of data interoperability.

If these factors cannot be brought together, the consideration of other necessary prerequisites (technical, economic, market-related, or legislative, such as measurement (baselines), settlement and pricing) will not even arise.

A similar logic is reflected in a paper by Michaelis et al<sup>15</sup> suggesting that the design process of local flexibility markets should be based on the following steps (i) define objectives, (ii) characterise market participants and roles, (iii) select core market design options. In their paper, they also built a taxonomy for the description and comparison of local flexibility markets (attached as Annex II). Another paper from Rebenaque et al. identifies four key challenges that need to be addressed for local flexibility markets to be implemented successfully: governance, TSO-DSO coordination, increase-decrease gaming and market entry barriers<sup>16</sup>. The paper also offers solutions for each of the challenge areas and lists the pros and cons of said solutions.

### 2.4.3 Barriers for (the existence and functioning of) local flexibility markets

Based on the responses provided in the 2 previously mentioned surveys, the following set of barriers have been identified:

- **Lack of awareness of current and future network flexibility needs**
- **Technical barriers:** missing smart meter rollout, low observability or no remote-control capable infrastructure
- **The role of the regulatory framework:** TOTEX/CAPEX bias, insufficient network charge incentive for grid users to consider flexible behaviour
- **Insufficient participation or low liquidity in local markets:**

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<sup>15</sup> [Anne Michaelis, Michael Schneider, Martin Weibelzahl: Designing local flexibility markets: A toolbox for policymakers and market operators, Energy, Volume 329, 2025](#)

<sup>16</sup> [Olivier Rebenaque, Carlo Schmitt, Klemens Schumann, Théo Dronne, Fabien Roques, Success of local flexibility market implementation: A review of current projects, Utilities Policy, Volume 80, 2023](#)

- Unclear, missing, or discriminative market (access) rules and roles (prequalification, product design, settlement rules)
- Specific barriers for certain types of potential service providers (independent aggregators, storage, demand response, DER, residential grid users, EVs etc.)
- Lack of interoperability—, both at a technical level and as interoperability between markets

In addition to these more operational barriers, it should be noted as a kind of strategic barrier that at least one Member State has a non-market-based mechanism in place, because it considers that the necessary prerequisites for an efficient market procurement cannot be met. Their main concern is that market power issues, increase-decrease gaming and abuse of market power are such a risk that may lead to an increase in redispatch volumes (although not necessarily on the DSO level). Therefore, MSs and NRAs should also carefully assess whether and to what extent this problem arises in their jurisdiction. A list of existing local flexibility markets and pilots thereof can be found in the Table in Chapter 3.3.

## 3 NRA's perspective on DSO's flexibility procurement

### 3.1 Processes relating to flexibility

The process of DSO flexibility procurement can be summarised through a process flow. This flow begins with a long-term strategic forecast and culminates in an operational action, the results of which then loop back to refine the initial strategy. This iterative loop ensures that network planning becomes an adaptive process, continuously informed by standardized data and real-world operational experience.

The D-NDP initiates the cycle by identifying potential future needs, the FNA then provides a standardized quantification and assessment of DSO network flexibility needs (some of which should also be included in the D-NDP pursuant to the draft DRNC), and finally, the procurement assessment determines the appropriate solution pathway (with or without derogations), and operational actions deliver the required service. The outcomes of these actions - in terms of cost, reliability, and market impact - provide the crucial data that informs and improves the next round of strategic planning, creating a reiteration of continuous improvement towards the identification of flexibility needs and the procurement of flexibility. The default option to examine is market-based flexibility procurement as per Article 13 of the Electricity Regulation and Article 32 of the Electricity Directive. However, this set of procedures also helps to identify on an ongoing basis the cases where market-based procurement continues to be inefficient or is not feasible. Should the operational assessment indicate that market-based procurement is not the best solution to move forward, the DSOs might use a derogation to be exempted from the default rule.

All these steps are discussed in turns below. It should also be noted that this is a rather theoretical approach. There are already established national processes in which certain key dates are specified in the planning process. Combining all these requirements can be challenging in practice.

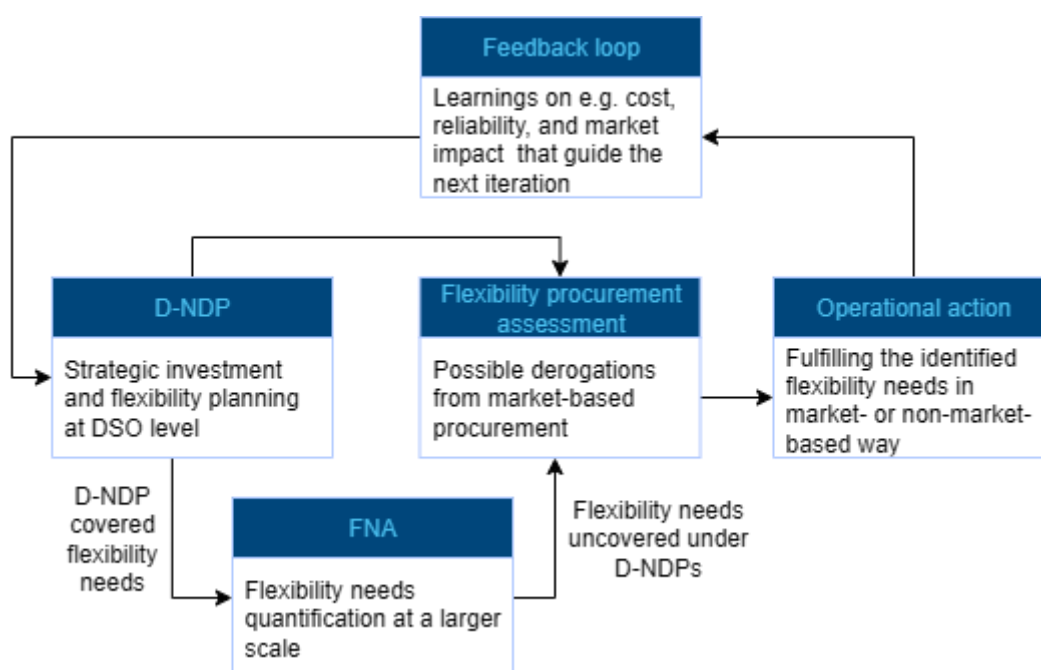


Figure 2 Illustration of the possible DSO flexibility procurement process flow

### 3.1.1 Distribution network development plans

The distribution network development plans (D-NDPs) are required EU-wide due to Directive (EU) 2019/944<sup>17</sup>. All DSOs are obliged to prepare D-NDPs unless the MS has decided to use the Directive's possibility to make exceptions for DSOs that serve less than 100 000 connected customers. The DSOs have to prepare the D-NDPs at least every two years. Regarding implementation of flexibility to the network there are a few requirements about what DSOs should present in their D-NDPs. The D-NDPs **have to be transparent on medium- and long-term flexibility services, as an alternative to system expansion**, including demand response, energy efficiency, energy storage or other resources. Also, DSOs have to emphasize their investments to the main distribution infrastructure required to connect new generation and new loads, including recharging points for electric vehicles.

Based on paragraph (22) of the preamble of the FNA methodology (FNAM), "the D-NDP is expected to be the main data source for the distribution level under the FNAM, as it provides transparency on the medium and long-term flexibility needs and outlines planned investments for the next 5 to 10 years" (except for DSOs with fewer than 100.000 customers, where the data may be based on other relevant sources<sup>18</sup>).

As regards flexibility resources, pursuant to paragraph (9) of the preamble of the FNAM, "according to Article 32(3) of the Electricity Directive, the DSOs' D-NDPs shall include the flexibility resources that the DSOs are to use as an alternative to system expansion. Therefore, this flexibility is, in principle, expected to be available to the DSOs. In the context of the

<sup>17</sup> European Parliament and Council of the European Union. (2019). Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity. Retrieved from: <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32019L0944>.

<sup>18</sup> In countries where the majority of DSOs have fewer than 100,000 customers and are therefore not required to provide DNDPs, the DNDPs are generally unsuitable as a data source for the FNA as they are not available. This presents a practical challenge.

nomenclature adopted by the FNAM, the flexibility identified in the DNDPs should be considered covered, i.e. expected to be available to DSOs for the target years considered”.

The new draft DRNC will also feature certain provisions relating to the D-NDPs, namely, on their content and how they should reflect the use of local services. Based on the draft, that might still be subject to change, the D-NDPs shall contain a description of the distribution system planning framework (which shall ensure amongst others effective and cost-efficient measures and transparency on the planning criteria and be based on scenarios), the scenarios used to identify network development needs (which shall also consider the National Energy and Climate Plans (NECPs)), information on relevant planned and ongoing investments (next 5-10 years) and information on local services. Regarding local services, the draft aims to oblige the DSOs to consider the use of local services to either alleviate or postpone network development or to address physical congestion or voltage issues until a reinforcement project is completed, where deemed relevant and cost-effective. Where the use of local services is considered relevant and cost-effective, D-NDPs shall include at least an assessment of the forecasted needs, a description of cost-effectiveness and information on the local services the DSO estimates to need in the medium and long-term. The new draft provisions also prescribe requirements towards the D-NDP's public consultation and publication.

CEER has published a paper about D-NDPs in 2021<sup>19</sup>. The paper provides CEER's views on what the DSOs should do and what the NRAs can do to implement the article 32 requirements for the D-NDPs in a transparent way. The paper brings forward that the DSOs should explain the planning methodology used to identify network development projects in the D-NDPs. Also, it is seen useful to assess and explain the interaction between the planning methodology and procurement of flexibility options in the D-NDPs.

### 3.1.2 Flexibility needs assessments

In June 2024, the Electricity Regulation was amended by EU regulation (EU) 2024/1747<sup>20</sup> to include a new Article 19e on the “Assessment of flexibility needs”. The article requires that every two years a regulatory authority or another authority or entity designated by a Member State shall adopt a report on the estimated flexibility needs for a period of at least the next 5 to 10 years at national level. This report should be based on the data and analyses provided by the TSOs and DSOs using common methodology. This common methodology for the flexibility needs assessment (FNAM) was prepared by ENTSO-E and EU DSO entity, where they

- defined the type and format of data that the TSOs and DSOs provide for the designated authority or entity
- developed a methodology for the analysis of the flexibility needs, taking into account all available sources of flexibility in cost-efficient manner in the different timeframes, planned investments in interconnection and flexibility and the need to decarbonize the electricity system in order to meet the Union's 2030 targets for energy and climate.

ACER approved the methodology in July 2025 and thus, the designated entities have 12 months to adopt the FNA report. In the report, the designated entity has to consider DSO

<sup>19</sup> CEER. (2021). CEER Views on Electricity Distribution Network Development Plans. Retrieved from: <https://www.ceer.eu/publication/ceer-views-on-electricity-distribution-network-development-plans/>

<sup>20</sup> European Parliament and Council of the European Union. (2024). Regulation (EU) 2024/1747 of the European Parliament and of the Council of 13 June 2024 amending Regulations (EU) 2019/942 and (EU) 2019/943 as regards improving the Union's electricity market design. Retrieved from: [https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=OJ:L\\_202401747](https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=OJ:L_202401747).

network flexibility needs as well (article 11). In doing so, the DSOs, considering the nationally coordinated spatial and voltage granularity, shall detail their network flexibility needs per direction (upward and downward), and, if applicable, per scenario as a summation of local maximum values of power (MW) and total energy (MWh) either during time blocks and/or during representative days for each target year, or as a minimum, for each target year.

In addition, each DSO shall provide the following: a. the source of data and the studies used to determine/assess its network flexibility needs; b. the scenario(s) used to define future generation, loads and energy storages in its network; c. the methods used to assess their network flexibility needs and to select representative days and time blocks.

As previously mentioned, certain flexibility needs have to be covered in the D-NDP, but based on paragraph (9) of the preamble of FNAM, these should be considered covered. Therefore, the FNA report has to identify covered and uncovered flexibility needs as well. For this, DSOs (and TSOs) need to provide indicators and analyses. DSOs shall provide the following indicators for the relevant target years: the location of the flexibility need in terms of geographical and voltage level; b. the direction of the flexibility need (upwards or downwards); c. the timeframe in which the resource shall be available to solve the flexibility need, including, if available, data such as the duration of a continuous need, the cumulated duration of discontinuous need per time block, a measure of the frequency of activation (level of recurrence or sporadicity), the cumulated energy per time block and the applicable economic criteria; d. the local maximum power required during the activation; e. other available relevant criteria agreed upon with the respective designated authority or entity and, in the latter case, also the regulatory authority. DSOs shall clearly indicate which part of the flexibility need is not expected to be covered and provide a reasoning for it.

Currently, needs for flexibility are assessed in different ways in different Member States. The CEER survey asked NRAs how the DSOs evaluate future connection capacity and flexibility needs. From the 21 surveyed NRAs, most of them answered that they do not know how DSOs are evaluating these flexibility needs. In MSs where at least some of the DSOs did evaluations, the mostly used methods were scenario building, simulations and modelling.

### 3.1.3 Derogation process according to Article 32

Article 32 of the Electricity Directive sets forth that MSs shall provide incentives to DSOs to procure flexibility services and to do so 'in accordance with transparent, non-discriminatory and **market-based procedures**' unless the regulatory authorities have established that some of the derogations mentioned in the directive applies: (i) the procurement of such services is not economically efficient or (ii) such procurement would lead to severe market distortions or (iii) to higher congestion. It is crucial that DSOs are in fact incentivised to consider flexibility procurement to increase their efficiency, and EU legislation prescribes to consider market-based procurement first. The overview of the national practices relating to these derogations is the one of the main purposes of this paper.

The derogation, based on Article 13 of Regulation is not addressed in this sub-chapter.

The new draft DRNC will also have relevant provisions on how to grant these derogations. Its relevant article proposes principles and requirements for the procurement of local services (congestion management and voltage control), further detailed rules to the derogation process from market-based procurement of local services: at least every 2 years, each system operator shall perform an assessment on the need and procurement of services from demand response, energy storage or other resources as alternatives to system expansion. By default, system

operators shall procure (or at least consider procuring) local services in accordance with a market-based mechanism, unless a derogation is applicable.

Based on the proposed Article 30 (3) of the draft DRNC, the derogation process shall be transparent, non-discriminatory, non-biased, well documented and based on reasoned grounds, and the derogation issued shall at least (a) take into account the latest D-NDPs including estimated needs for local services and available resources, DSOs observability areas, and the national assessment on flexible connection agreements, where applicable; (b) specify, where relevant, the parts of the system, the voltage levels, the time periods, and the products, especially short-term and long-term products that it applies; (c) take into account the size of the DSO(s); (d) specify its duration, which shall not be longer than two years, unless it is a derogation for the procurement of voltage control services with reactive power, which can be longer; and (e) be published on its website.

### 3.1.4 Interlinkages between D-NDPs, FNAs and the derogation processes

The processes governing DSO flexibility procurement—strategic planning via D-NDPs, additional quantitative analysis through the FNA, and the operational choice between market-based and non-market mechanisms (in the end potentially resulting in a derogation request based on article 32 of the Electricity Directive unless an exemption is already in place under Art. 13 of Regulation)—are not separate, siloed activities. They can be thought to form a cyclical and interdependent process designed to integrate flexibility into every stage of grid management, from long-term investment decisions to real-time operations.

The following table visualizes the interconnected stages of the DSO flexibility procurement 'planning' process, highlighting the inputs, outputs, and governing regulations at each step. It illustrates how the output of one stage serves as the primary input for the next, demonstrating the cyclical nature of the framework. It should be noted that this is an interpretation of how the legislative building blocks could work in tandem with each other. Colour coding is used to help with interpretation of what is **legislatively in effect** and **what is not yet**<sup>21</sup>, and which parts **do not come from any legislation**<sup>22</sup>.

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<sup>21</sup> Legislatively provided for, but not yet fully implemented (e.g., in draft status, deadlines are in the future, methodologies are being applied for the first time).

<sup>22</sup> Does not come from any specific legislation; it's a logical process step, best practice, or interpretation.

Table 1 Activities of DSOs in the context of D-NDPs and FNA relating to flexibility procurement

Process Stage	Key Activity	Primary Input(s)	Key Output(s)	Governing Regulation(s)
1. Strategic Planning via D-NDPs	DSO develops and publishes its network development plan, (Art. 32)	The National Energy and Climate Plans (NECPs), historical load/generation data, technology uptake scenarios, previous FNA report findings.	Published D-NDP identifying medium/long-term flexibility needs (location, volume, duration).	Art. 32, Directive (EU) 2019/944, NC DR draft
	forecasting needs and comparing "wires" vs. "flexibility" solutions. (NC DR)			
2. Further Flexibility Needs Quantification via the FNA	National-level, standardized assessment of flexibility needs (FNA) based on a common methodology.	D-NDP data from DSOs, European and National Resource Adequacy Assessments (ERAA/NRAA) data from TSOs.	National FNA Report quantifying system and network needs (especially those uncovered in D-NDPs); informs national targets.	Art. 19e, Regulation (EU) 2019/943 (as amended by EMDR), FNAM
3. Flexibility Procurement Assessment	Unless already exempted from market-based procurement by the MS (Art 13), or by the NRA (Art 32),	D-NDP, FNA Report, assessment of local market liquidity and competition.	Decision to: <b>A:</b> Proceed with market-based procurement. <b>B</b> Seek derogation (Art. 32 Directive, Art. 13 Regulation) <b>C:</b> A combination of A and B depending on the location.	Art. 32, Directive (EU) 2019/944; Art. 13, Regulation (EU) 2019/943
	the DSO assesses the feasibility of market-based procurement for needs identified and quantified in the D-NDP and the FNA			

4. Operational Action for Flexibility Procurement	<p><b>Path 0:</b> No flexibility needs identified</p> <p><b>Path A (Market):</b> DSO procures services via tenders/platforms.</p> <p><b>Path B (Non-Market):</b> DSO uses e.g. redispatch (rules-based) i) after NRA derogation (Art. 32 Directive) or ii) as an MS option based on Art. 13 Regulation.</p> <p><b>Path C (coexistence of MB and non-MB):</b> Tariff- and connection agreement-based solutions, and in some cases rules-based<sup>23</sup> used alongside market-based.</p>	<p><b>0:</b> No assessment needed.</p> <p><b>A:</b> Bids from market participants.</p> <p><b>B:</b> i) Derogation from NRA, ii) MS/NRA details on the rules-based approach.</p> <p><b>C:</b> Combination of A and B i) depending on the setup.</p>	<p><b>0:</b> Network investment needed.</p> <p><b>A:</b> Activated flexibility service.</p> <p><b>B:</b> i) Use of non-MB instrument ii) E.g. Redispatch instruction (e.g., curtailment).</p> <p><b>C:</b> A combination of the two which depends on the specific location in the network</p>	Market rules, Network Codes, National implementation of compensation
5. Feedback Loop	Results of procurement (costs, reliability) and redispatch (volumes, costs) inform future planning.	Operational data, market outcomes, redispatch reports, action plans to resolve congestion.	Inputs for the next D-NDP cycle and FNA process, potential refinement of regulatory incentives.	N/A

<sup>23</sup> Rules-based and market-based are mutually exclusive for the same user group within the same geographical location

## 3.2 Derogation process from market-based procurement under Article 32 of the Electricity Directive

This section outlines the NRAs' role regarding the derogation process under article 32, current NRA expectations about flexibility needs and viability of market-based solutions and the status of derogations under the article 32. It is to be noted, that according to one NRA, this derogation correlates with the Member State's execution of the non-market-based option in accordance with Article 13 of the Regulation.

### 3.2.1 Role of the NRA

The NRA is the central actor in the derogation process according to Article 32 of the Electricity Directive, it is the assessor, gatekeeper, and ongoing supervisor of the entire flexibility procurement framework at the national level.

First, the Member State and the NRA are in accordance with their legal empowerment responsible for designing the broader regulatory framework that governs DSO flexibility procurement. This includes creating incentive schemes that encourage DSOs to explore flexibility options and for the NRA, designing tariff/revenue methodologies that consider both capital and operational expenditure and network tariffs that send efficient price signals to grid users, incentivising them to increase behavioural flexibility and act as potential flexibility service providers. A well-designed framework can foster the development of a flexibility market, increase liquidity and otherwise support functioning of the market.

Second, the responsibility for conducting the due diligence to assess whether the conditions for a derogation are met lies squarely with the NRA, not the DSO. The DSO can provide data and analysis, but the final determination must be made independently by the regulator. This ensures an objective assessment of the market's viability.

Third, in cases where the NRAs have established that the market-based procurement of such services is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion, the NRA's role shifts to supervision. It must approve the specific non-market mechanism to be used and, crucially, the methodology for compensating the affected parties (if applicable). Also, the NRA might prescribe actions to be taken in order to further the development of a market-based solution.

### 3.2.2 Current understanding and future expectations of flexibility needs at a national level

In 62 % of the surveyed countries, DSOs have not yet assessed how much flexibility service is needed to cover the local needs. Therefore, it is difficult to estimate how long it will take to satisfy the local needs. TSOs obviously have a better understanding of their flexibility needs than DSOs do, because TSOs are typically responsible for the overall balancing of the electricity system and there are decades of experience with congestion management at the transmission level. It seems that in most of the surveyed European countries, it is not realistic to assume that local flexibility needs can be satisfied exclusively by market-based procurement within the next 5 to 10 years. 19 % of NRAs see market-based procurement to meet local flexibility needs as a more realistic expectation within a 10+ year horizon, not earlier.

However, some NRAs see that, at least at the distribution level and for example in scarcely populated areas or due to high market concentration, there will always be situations where the market does not function efficiently. Furthermore, there are fundamental issues that remain unclear with market-based flexibility procurement, such as market power, aggravation effects concerning congestions with market-based procurement, increase-decrease gaming, abuse of market power and discrimination issues. Therefore market-based procurement cannot be expected to efficiently resolve every local congestion situation, and exemptions will be justified for the foreseeable future.

### 3.2.3 Status of national derogation processes from Article 32

The specific practices concerning the derogation process under Article 32 vary somewhat between countries. Based on the survey, the application for an exemption is initiated by the DSO or the NRA, depending on the country. In 62 % of surveyed countries, the process has not yet been defined and only two NRAs have a specified form to be filled. Some NRAs use a formal request with the necessary legal/regulatory framing and justification for the request.

The survey also inquired on whether the MS or the NRA applies the same process for derogation under Article 13 of Electricity Regulation as Article 32 of Electricity Directive<sup>24</sup>. Unfortunately, the responses seem to be inconclusive, because, on the one hand, there were four respondents who replied with 'no', four respondents who did not answer to this particular question, and 13 who answered 'yes', on the other hand, cross-checked with other answers it became clear that some Member States who have not yet applied/defined any of the derogations either answered 'no' or 'yes'.

In Estonia, a DSO shall provide sufficient data (market analysis, procurement results) to prove that the market-based procurement of flexibility is economically inefficient. The DSO must report on its respective pilots and endeavours to develop flexibility markets and they also must report on potential market players (if any).

In Finland, the DSOs must recognize the types of future flexibility needs in the application for derogation from market-based procurement of flexibility. Any further quantification of these flexibility needs is not currently required but may become part of the application process in the next five years. However, already currently, DSOs must describe in the D-NDPs how much they are planning to invest and are they going to use flexibility as an alternative solution.

In most of the countries that responded, the DSO must propose measures (e.g. establish procurement conditions) to achieve market-based procurement. In countries where the process is defined, the process is based on or enables dialogue between the NRA and the DSO.

50 % of countries where the derogation process is defined, answered that exemptions are granted for 1-2 years at a time and others that it is granted for an indefinite period. For all the

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<sup>24</sup> It became clear that Article 13 of Electricity Regulation and Article 32 of the Electricity Directive (and their relationship) have overlapping legislative subjects, which leaves room for several interpretations.

cases where there was a fixed term, the conditions for renewing the derogation were the same as for the first application.

Derogations may be accompanied by some obligations. In Finland, DSOs need to monitor market developments and BRUGEL in the Brussels region of Belgium is planning to impose some obligations to the DSO to implement a monitoring of the improvement of their capabilities and identify their needs for flexibility procurement services.

In Finland and Hungary, all DSOs have applied for the exemption, whereas in other countries there have only been individual applications, if at all. In Finland, almost all applicants have already been granted an exemption, while in Hungary the applications are in process. According to the responses, no country has yet rejected a request.

In Germany the MS's option of the non-market-based redispatch procurement based on Article 13 of the Electricity Regulation applies. According to this interpretation, non-market-based redispatch procurement therefore replaces the market-based procurement.

### 3.2.4 Currently used justifications and criteria for a derogation

As was mentioned earlier, the EU Directive allows for derogations from Article 32 on three specific grounds: if market-based procurement leads to 1) economic inefficiency, 2) market distortions or 3) higher congestion. As some NRAs have already granted derogations, they have also justified the derogations based on one or several of these reasons. However, given that derogations are quite new, NRAs **do not seem to yet have robustly established criteria for each of them.**

Currently, the main grounds for granting a derogation are that market-based procurement is not economically viable or leads to market inefficiencies, or there are no available market-based options.

Based on the survey responses, some potential indicators to assess market distortions, economic inefficiency and higher congestion are summarised in the list below.

Table 2 Potential indicators that different NRAs see plausible to assess market distortions, economic inefficiency and higher congestion

Dimension	Metric
<i>Market Conditions &amp; Participation (maturity, distortions, inefficiencies)</i>	
Demand for Flexibility	<ul style="list-style-type: none"> <li>- DSO readiness/capabilities to procure flexibility (SI, BE<sup>25</sup>)</li> <li>- Scale of DSO needs (via the D-NDP) (LV; BE)</li> <li>- Load rate &amp; capacity (BE)</li> </ul>
Supply of Flexibility	<ul style="list-style-type: none"> <li>- Flexible load capacities (BE)</li> <li>- Number of participants or offers (HU; EE)</li> </ul>
Market Functioning	<ul style="list-style-type: none"> <li>- Market availability (FI)</li> <li>- Gaming issues (DE)</li> <li>- Complaints and market monitoring report (MMR) (LV)</li> <li>- Electricity losses (LV)</li> </ul>

<sup>25</sup> Belgium's (BE) responses only refer to BRUGEL's Brussels region.

	- Flexibility utilisation rate by DSO (SI) - DSO's performance on establishing flexibility markets (IE)
<i>Congestion Status</i>	
	- Redispatch volumes & costs (DE)

This collection of answers also invites to reflect on the barriers listed Chapter 2.4.3: it suggests that the removal of barriers is not only crucial for the development, but also of the proper functioning of a local flexibility market. It is important to be reminded that the national FNA report to be prepared by July 2026 shall, amongst other things, 'evaluate the barriers for flexibility in the market and propose relevant mitigation measures and incentives, including the removal of regulatory barriers and possible improvements to markets and system operation services or products' (Article 19e (2) c) of the Electricity Regulation).

### 3.3 Flexibility in regulatory cost recognition/tariff methodology

The topic of DSO flexibility procurement ties into the subject of how flexibility related costs are recognised by the current DSO tariff or remuneration methodology. This is also recognised in the Article 32 of the EU electricity directive as it states that DSOs should be incentivised to use flexibility.

Recent work by CEER<sup>26</sup> identified potential CAPEX biases that may arise within DSO regulatory frameworks for remuneration and tariffs, and how some of these biases could be addressed and alleviated with specific regulatory framework design choices. This is important also in the sense that the incentives for DSOs should be aligned so that DSOs develop their networks in the most cost-efficient, technology neutral way and consider all possible solutions. This alignment therefore also ties into the before discussed D-NPD processes and possible derogations from Article 32.

If the regulatory framework in place disincentives the use of flexibility, this can hinder DSOs' use of flexibility and therefore also slow down the development of flexibility markets. This can also impact how DSOs set their D-NPDs and the propensity to apply for a derogation from Article 32, although there is no evidence of such behaviour taking place.

JRC (2022) also found that 'national regulatory frameworks play a major role in empowering DSOs to take a more active role both as buyers of distributed flexibility and in facilitating others' use of flexibility resources in their own networks' and that in all of the countries analysed in their report (FR, DE, NL, NO, SE, UK), DSOs' revenues models are based on incentive regulation using a TOTEX approach and uses benchmark against comparable DSOs. Beyond that, R&D represents a major part of the innovation incentives provided to the DSOs and R&D costs are in many cases 'partially recovered by increasing the revenue allowance upon compliance with a set of eligibility requirements and directly passed through tariffs (and therefore is not subject to efficiency benchmarking)'.

The CEER survey for NRAs also covered questions concerning how flexibility related costs are currently recognised in the tariff/revenue remuneration methodology. Below is a summary table based on the survey responses.

<sup>26</sup> CEER (2025) [CEER Paper on Incentives in Regulatory Frameworks with a Focus on OPEX/CAPEX Neutrality - CEER](#)

Table 3 Current status of incentives and cost recognition concerning flexibility across Europe

Country	Existing local flexibility services	Flexibility costs recognised/evaluated by the tariff/remuneration methodology	Market-based (MB), non-MB, both	Overall tariff methodology approach <sup>27</sup>	Dedicated incentives for flexibility via regulatory framework (e.g. explicit or implicit via output-based regulation)	Dedicated incentives for flexibility via government scheme or obligation
Austria		Not yet defined		TOTEX		
Belgium		Not yet defined	Non-MB (Walloon)	Non TOTEX	In planning (Brussels)	
Czech Republic		Not yet defined		Non TOTEX		
Germany		Recognised by the methodology	Non-MB	TOTEX		
Estonia		Not yet defined		Non TOTEX		
Finland	NODES (FinFlex)	Recognised by the methodology	Both	Non TOTEX	Yes	
France	Enedis' Local Flexibility market	Recognised by the methodology	Both	Non TOTEX	Yes, but not explicit (output-based), explicit in planning	
Great Britain	Piclo Flex	Recognised by the methodology	Both	TOTEX	Yes, but not explicit (output-based)	
Croatia		Not yet defined		Non TOTEX		
Hungary	Flex.ON	Not yet defined		Non TOTEX		Yes
Ireland	Piclo (ESB Networks)	Recognised by the methodology		Non TOTEX	Yes	
Italy	Pilots <sup>28</sup> :	Recognised by the methodology	MB	TOTEX	Yes, but not explicit (output-based)	

<sup>27</sup> Based on the assessment done in CEER (2025) Incentives in Regulatory Frameworks with a Focus on OPEX/CAPEX Neutrality

<sup>28</sup> Fully market-based initiatives for congestion management (ancillary services for active power regulation to manage distribution congestion). Managed by DSOs with the support of GME (Italy's Market Operator) in two cases. More details are presented in Annex III.

	EDGE (E-distribuzione), RomeFlex (Areti/GME) and MiNDFlex (Unareti/GME)					
Lithuania		Recognised by the methodology, remunerated through the tariffs	Both	Non TOTEX		
Latvia		Recognised by the methodology		Non TOTEX		
Malta		Not yet defined		Non TOTEX		
Netherlands	GOPACS	Recognised by the methodology	Both	TOTEX	Yes	
Poland		Not yet defined		Non TOTEX		
Portugal	Piclo (E-Redes)	Not yet defined		TOTEX		
Romania		Recognised by the methodology	MB	Non TOTEX		
Sweden	NODES (Sthlmflex)	Recognised by the methodology	Both	Non TOTEX	Yes, but not explicit	
Slovenia	Prožnost <sup>29</sup> (Elektro Ljubljana)	Recognised by the methodology	MB	Non TOTEX	Yes <sup>30</sup>	No <sup>31</sup>

<sup>29</sup> Flexibility procurement is facilitated through the national data hub Moj elektro. Info pages: <https://www.elektro-ljubljana.si/proznost>

<sup>30</sup> Explicit, an efficiency KPI that depends on DSO's flexibility utilisation (output-based regulation). This KPI is included with other KPIs in calculation of the "umbrella KPI" for efficient investments in new (smart grid) solutions. A deviation from the baseline is calculated and it is directly linked to the financial incentive which may be positive or negative.

<sup>31</sup> The latest amendment of the Law for supply of electric energy in its Article 23 (<https://pisrs.si/pregledPredpisa?id=ZAKO9115>) introduces provisions for a "Non-fossil flexibility support scheme" in line with Article 19g of the REGULATION (EU) 2019/943.

Based on the responses, the current practices regarding how countries evaluate flexibility procurement related costs in tariff or remuneration methodology vary quite significantly. In many of the surveyed countries, the process is not yet defined given that there are no flexibility procurement related costs for DSOs at least for the time being, some noting also that flexibility procurement is currently mainly the role of the TSO. A few of these countries do however envisage that the explicit treatment of these costs will be considered for the next tariff methodology period for the DSOs.

Within those that do currently recognise these costs, practices also vary. Most countries recognise both market-based and non-market-based costs (both categorized as operational costs) and do not, at least for the time being, differentiate between these cost categories<sup>32</sup>. There are also a few examples where only market-based related costs or only non-market based related costs are recognised. These edge cases seem to stem directly from the different regulatory approaches to flexibility procurement that we have witnessed across Europe. In cases where DSOs do incur costs for congestion management, these costs can be remunerated through network tariffs. In one country, flexibility procurement was at a pilot level and those costs were covered by the tariff methodology.

Furthermore, in some countries, flexibility procurement related costs are part of the efficiency criteria, whereas in others, only non-market-based costs have an efficiency requirement while market-based costs are allowed to be passed through.

In two of the analysed countries (Ireland and Finland<sup>33</sup>), there were direct incentives in place specifically for flexibility. In many other countries, there were output based incentives in place that can be argued to also indirectly incentivise the use of flexibility related measures.

### 3.4 Economic valuation of flexibility

Both non-market based and market-based flexibility can have economic value, but only the value of market-based flexibility is observable via the market forces of supply and demand and even in that case it is not necessarily an efficient price. Since non-market-based flexibility has to be somehow quantified in order to determine any economic value for flexibility from these sources, we asked MS/NRAs to describe, if possible, their methodology for quantifying costs and/or benefits for applying non-market-based flexibility procurement.

Very few NRAs applied a specific valuation methodology for non-market based flexibility, but based on the survey responses, there are also country practices concerning the valuation and cost recognition of flexibility procurement more generally that can be drawn learnings from. These tools can also be used to contrast a clearing price for market-based flexibility. For example, in Great Britain, DSOs utilise a common evaluation tool<sup>34</sup> to decide which intervention is economically justified, whether that be a flexibility service, an asset reinforcement or an alternative innovative solution. It is a CBA tool that assesses the counterfactual option (grid reinforcement) against any number of alternatives. A wide range of costs are inputted into the model, direct costs stemming from the alternative options and wider network and societal costs

<sup>32</sup> Although one NRA noted that only market-based related costs were recognised due to the fact that non-market based procurement of flexibility was not remunerated and did not incur any additional direct costs for the DSO.

<sup>33</sup> See DSO Observatory (2024) p. 72 for further

<sup>34</sup> ENA (2024) Common evaluation methodology and tool: <https://www.enwl.co.uk/globalassets/future-energy/flexibility-hub/document-library/cem-tool/ena-common-evaluation-methodology-v3.0.pdf>

(impact of network losses, potential asset condition driven changes in Customer Interruptions and Customer Minutes Lost, carbon emissions, and a range of other impacts measured in the original Ofgem CBA tool). A typical scenario is where the alternative options allow the grid reinforcement to be deferred further into future.

The outputs of the model produce a ceiling price for alternative options, i.e. the maximum balance responsible party cost of the flexibility solution before it becomes less economic than the traditional asset solution. This ceiling price can be used as reference for valuing flexibility, which can be especially useful in cases where there is no market clearing price for a flexibility solution, which is the case for non-market-based solutions, or the market outcome is inefficient due to the possible abuse of market power. Other NRAs noted similar approaches to link the value of flexibility to the calculated avoided or postponed grid reinforcement costs, albeit in a simpler, "non-CBA" way.

On the other hand, Germany utilises a non-market-based approach to procure flexibility for congestion management. The value of flexibility in the framework is determined by the incurred costs of upward and downward regulation/redischpatching. In case of upward regulation, it is the variable cost (mainly fuel cost). In the case of downward regulation, it is the compensated loss of foregone profits from the spot market minus the avoided variable cost. Downward regulation often results in a payment from the generator to the DSO.

Based on some Member States' experience, NRAs should be aware that in some **specific cases** of FCAs, where flexibility can be activated without operational costs for the DSO (within the limitations of the specific agreement) without any further payment obligations **and that can be used with the same effect as congestion management**, special regard should be given to the fact that these use-cases do not reflect the value of the flexibility for the system and the lost value for the grid user and requires complex coordination. Therefore, in these cases, NRAs should give special attention to the incentives and cost implications that these use-cases carries. On the other hand, **generally, flexible connection agreements** as a solution to better meet the quickly increasing demand of network connection capacity and for shortening of the connection queue **can grant earlier access to the grid for the user, which has its benefits** that are not necessarily explicitly priced in into the agreement either.

## 4 Conclusions, findings and recommendations

Several conclusions, observations and recommendations can be drawn from the analysis relating to how flexibility procurement of distribution system operators is carried out across Europe:

The development of market-based flexibility procurement by distribution system operators is inhibited by several information, technology and market-related barriers. One of these is lack of knowledge of current and future network flexibility needs, which the FNA methodology could help to address. In terms of technical barriers, incomplete smart meter rollout, low observability or lack of interoperability also seem to act as barriers for market-based flexibility procurement by the DSOs. Market-related barriers include unclear, missing, or discriminative market (access) rules and specific barriers for certain types of potential service providers.

The prevalence and the pace of flexibility market developments seem to be partly dependent on the severity of the current congestion and connection challenges faced (the drivers). Currently, it seems that the network congestion related pressure to develop a market-based solution for these issues has to be strong enough for system operators to start considering to develop solutions for the many barriers at hand. Also, NRAs should be mindful that long connection queues can hide or postpone flexibility needs: if there is no sufficient incentive for the DSO to connect the grid users in a timely manner, this can push the manifestation of flexibility needs further into the future.

As regards the different European processes governing DSO flexibility procurement, it is useful to view these (D-NDPs, FNAs and the derogation process) as interdependent steps that provide feedback between each other as flexibility is integrated into every stage of grid management. It is important to pinpoint, that even under European legislation, market-based flexibility procurement is not a goal in itself, but a starting point for the investigation to identify the most efficient solution for the DSOs to operate and develop their network. Should market-based procurement prove inefficient or otherwise unfavourable, both the Electricity Regulation and Directive offer possibilities for derogation.

As regards the derogation from the default market-based flexibility procurement by DSOs, there is an established derogation process in place in less than half of the surveyed European countries. Of those, 3 MSs have granted derogations for all the DSOs, the rest are still in the process. No country has yet denied a derogation application. Around 50% of the respondents grant the derogation for a period between 1-2 years and in around 50% of the cases, the DSO does propose an action towards reaching market-based procurement.

The analysis concerning the current derogation processes did however identify gaps in more detailed assessment due to lack of robust and well-established indicators for the three specific grounds that derogations can be based on (economic inefficiency, market distortions or higher congestion). It is possible that the FNA reporting can fill in some of these missing indicators for flexibility procurement once the process gets underway. The currently applied and suggested indicators mainly focus on market conditions and participation.

The regulatory framework in place for network remuneration can also impact the lengths at which DSOs are interested to explore alternative solutions to grid congestion issues and incorporate network flexibility in strategic planning. TOTEX-based regulation and other design choices can help bring different solutions to equal grounding in the decision-making process. Flexibility inducing or at least reflective network tariff designs can also lay the groundwork for market-based solutions to develop.

In terms of the valuation of flexibility, there are a few examples that can be drawn learnings from, however, it is not an exhaustive analysis. These include for example using the cost of grid reinforcement or network buildout as the baseline cost for valuing the alternative approach of flexibility, or alternatively valuing this flexibility indirectly via the direct costs involved in upward (variable fuel costs) or downward regulation (foregone profits minus the avoided variable fuel costs).

NRAs should also be mindful of the potential side effects of allowing DSOs to take advantage of "free flexibility" via for example flexible connection agreements without any payment obligations that are designed to mimic congestion management, as it can distort the development of market-based solutions. On the other hand, flexible connection agreements, which can take many forms, can also lay the groundwork for market-based solutions to develop if these connection agreements are temporary in nature as they typically are.

## Annex 1 – List of abbreviations

Term	Definition
CAPEX	Capital Expenditure
CEER	Council of European Energy Regulators
D-NDP	Distribution Network Development Plan
DSO	Distribution System Operator
ERAA	European Resource Adequacy Assessments
FNA	Flexibility Needs Assessment
MMR	Market Monitoring Report
MS	Member State
NECPs	National Energy and Climate Plans
NRAA	National Resource Adequacy Assessments
NRA	National Regulatory Authority
TSO	Transmission System Operator

## Annex 2 – Taxonomy of LFM

Anne Michaelis, Michael Schneider, Martin Weibelzahl: Designing local flexibility markets: A toolbox for policymakers and market operators, Energy, Volume 329, 2025

A. Michaelis et al.

Energy 329 (2025) 136051

**Table 3**  
Taxonomy of LFMs.

Category	Dimension	Characteristic				Ex			
Objective	Energy security	Voltage control	Frequency control	Congestion management	Grid resilience and restoration	NEx			
	Energy equity	Revenue stream		Cost reduction	Investment signal	NEx			
	Environmental sustainability	CO <sub>2</sub> -emission reduction	Certification of local and green electricity	Resource conservation	Biodiversity preservation	NEx			
Participant	Flexibility Service Provider	Controllable unit owner	Aggregator	BRP	DSO	NEx			
	Flexibility buyer	Controllable unit owner	Aggregator	BRP	DSO	TSO	Supplier	End consumer	NEx
	Market operator	Aggregator	DSO	TSO	Regulator	Independent third-party	Ex		
Platform	Owner	Aggregator	DSO	TSO	Regulator	Independent third-party	NEx		
	Entry requirement	Technical	Geographical	Economic	Ecological	Policy	NEx		
	IT infrastructure	Centralised				Decentralised	Ex		
	Control of controllable unit	Market operator	Flexibility service provider	Flexibility buyer	Independent third-party	Ex			
	Metering	Metering point		Metering technology	Time granularity	NEx			
	Settlement	Balance responsibility		Imbalance settlement	Billing frequency	NEx			
	Platform integration	Island mode		Coordination with other electricity markets			Ex		
	Product	Flexibility source	Demand-side flexibility		Supply-side flexibility	Storage flexibility	NEx		
Baselining method		Committed schedule	Historical data	Metering data	Technology	Control group	NEx		
Differentiation		Different flexibility products			Only one flexibility product		Ex		
Level of commitment		Reservation			Activation		NEx		
Direction		Up-regulation			Down-regulation		NEx		
Start time		Configurable			Fixed		NEx		
Duration		Configurable			Fixed		NEx		
Volume		Configurable			Fixed		NEx		
Power modulation		Configurable			Fixed		NEx		
Activation frequency		One-time			Multiple times		NEx		
Quality requirement		Deviation time availability	Deviation duration	Deviation volume	Deviation power modulation	Deviation activation frequency	NEx		
Price components		Reservation price		Activation price	Penalty price		NEx		
Grid level		High voltage-level		Medium voltage-level	Low voltage-level		NEx		
Trade		Trade trigger	Use of traffic light concept	Request by market participant	Active in certain time windows	Always active	NEx		
		Start of trading	Several days/weeks/months before delivery		Day before delivery	Day of delivery	NEx		
	Gate closure	Several days/ weeks/months before delivery	Day before delivery	Hours before delivery	Minutes before delivery	NEx			
	Market clearing frequency	Pre-defined time interval			Continuously		NEx		
	Bid prioritisation	Prioritisation of specific participants			No prioritisation		NEx		
	Allocation mechanism	Auction	Continuous order book	Bilateral negotiation	Supermarket		NEx		
	Pricing rule	Pay-as-bid	Pay-as-cleared	Vickrey-Clarke-Groves-Price	Linked to other prices		NEx		

BRP = Balance responsible party, DSO = Distribution system operator, TSO = Transmission system operator, Ex = Exclusive, NEx = Non-exclusive

## Annex 3 – A summary of Italian local DSO flexibility market pilots

Pilot Project	DSO Manager /	Market Type	Type of Flexibility	Market Mechanism	Services Procured	Geographic Scope	Status / Notes	Provider	Cost Coverage Mechanism (ARERA decisions)
RomeFlex	Areti / GME	Market-based	Congestion management (active power)	Forward auctions and spot auctions (second phase)	Ancillary services for active power regulation to manage distribution congestion	Rome distribution network	Operational since 2023	GME (market operator): manages bidding, clearing, settlement, reporting, ensures compliance	Covered by Fund for Exceptional Events, Resilience, and Other Special Projects (ARERA 372/2023/R/eel)
EDGE	E-Distribuzione	Market-based	Congestion management (active power)	Forward auctions	Ancillary services for active power regulation to manage distribution congestion	Variou locations (4 provinces)	Pilot launched 2024, first auctions May 2024	DSO-managed with external IT support; GME not directly involved	Covered by Fund for Exceptional Events, Resilience, and Other Special Projects (ARERA 365/2023/R/eel)
MiNDFlex	Unareti / GME	Market-based	Congestion management (active power)	Forward auctions	Ancillary services for active power regulation to manage distribution congestion	Milano distribution network	Pilot started 2024	GME (market operator): manages auctions, settlement, reporting, transparency & compliance	Covered by Fund for Exceptional Events, Resilience, and Other Special Projects (ARERA 117/2024/R/eel)

## Annex 4 – About CEER

The Council of European Energy Regulators (CEER) is the voice of Europe's national energy regulators. CEER's members and observers comprise 39 national energy regulatory authorities (NRAs) from across Europe.

CEER is legally established as a not-for-profit association under Belgian law, with a small Secretariat based in Brussels to assist the organisation.

CEER supports its NRA members/observers in their responsibilities, sharing experience and developing regulatory capacity and best practices. It does so by facilitating expert working group meetings, hosting workshops and events, supporting the development and publication of regulatory papers, and through an in-house Training Academy. Through CEER, European NRAs cooperate and develop common position papers, advice and forward-thinking recommendations to improve the electricity and gas markets for the benefit of consumers and businesses.

In terms of policy, CEER actively promotes an investment friendly, harmonised regulatory environment and the consistent application of existing EU legislation. A key objective of CEER is to facilitate the creation of a single, competitive, efficient and sustainable Internal Energy Market in Europe that works in the consumer interest.

Specifically, CEER deals with a range of energy regulatory issues including wholesale and retail markets; consumer issues; distribution networks; smart grids; flexibility; sustainability; and international cooperation.

CEER wishes to thank in particular the following regulatory experts for their work in preparing this report: Farid Fodil-Pacha, Jaakko Kennilä, Sari Kolu, Judit Krajcs, Maija Laine and Emmi Puputti, with invaluable input from Gerald Kalt.

More information is available at [www.ceer.eu](http://www.ceer.eu).

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